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ONTARIO ENERGY BOARD

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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. Need to Reset and Refine Existing Return on Equity Formula: 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.

[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 not 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

[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.
>
> [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

[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

[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

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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

[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

[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.

[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 2nd 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.

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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

[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:

$ROE_t = 9.35\% = 0.75 \times (LCBF_t – 5.50\%)$

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.

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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.

TAB 2

EGI Recent Issuances Compared to OEB Deemed Long-term Debt Rate

Line	Year	Tenor (years)	Actual EGI Coupon Rate	Deemed OEB rate	Delta	Principle($ million)	Annual Interest variance ($ Million)	
1	2022	10	4.15%	3.49%	-0.66%	325	-2.15	
2	2022	30	4.55%	3.49%	-1.06%	325	-3.45	
3	2023	5	5.46%	4.88%	-0.58%	250	-1.45	
4	2023	10	5.70%	4.88%	-0.82%	400	-3.28	
5	2023	30	5.67%	4.88%	-0.79%	350	-2.77	
Sources:		*Exhibit N-M2-8-SEC-40, c)*		*Exhibit M2, Figure 37*			-13.09	<--- Interest expense not recovered in rates (would need to be converted to revenue requirement for full impact)

OPG Recent Issuances Compared to OEB Deemed Long-term Debt Rate

Last 5 debt issuances impacting OPG's Regulated Operations as of June 30, 2024

Line	Year	Tenor (years)	Actual OPG Coupon Rate	Actual OPG Effective Rate	Deemed OEB rate	Delta vs Coupon Rate	Principle ($ million)	Annual Interest variance ($ Million)
1	2024	10	4.83%	5.08%	4.58%	-0.25%	496.7	-1.24
2	2024	30	4.99%	5.17%	4.58%	-0.41%	496.2	-2.03
3	2022	10	4.92%	4.98%	3.49%	-1.43%	297.9	-4.26
4	2018	30	3.84%	3.92%	4.16%	0.32%	417.1	1.33
5	2019	30	4.25%	4.34%	4.13%	-0.12%	0.4	0.00
Sources:			*Exhibit N-M2-8-SEC-40*		*Exhibit M2, Figure 37*			-6.20

<--- Interest expense not recovered in rates (would need to be converted to revenue requirement for full impact)

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

- 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 2nd 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

TAB 3

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.39]

Question(s):

In SEC's experience, debt issuance/transaction costs on debt may or may not be material cost (e.g. bond issuance for large utility vs. bank loan for a small distributor, even proportionately can have very different costs). Furthermore, utilities who include a transaction cost as part of the interest rate often apply a 5-basis point adder regardless of the actual costs.

a) Please provide Concentric's views on when it is and is not appropriate to include transaction cost as part of the long-term debt rate.

b) For each CLD+ utility, please confirm that it recovers its debt issuance/transaction costs entirely through the amortizing costs over the life of a debt instrument. If not confirmed, how are those costs recovered.

c) For each CLD+ utility, for each of its last 5 debt issuances, please provide the, i) actual transaction issuance/costs (that would otherwise not be funded out of base rates), ii) based on the debt amount and term, the effective interest rate of the actual transaction costs when amortized over the life of the debt instrument, the iii) actual incremental amount that was added to the issuance debt rate for transaction/issuance.

Response:

a) Please see Concentric's report, Exhibit M2, at 39-40, where Concentric proposes to maintain the status quo with regard to the treatment of debt issuance/transaction costs and provides support for that recommendation.

b) Toronto Hydro – Confirmed.
Alectra – Confirmed.
Enbridge Gas Inc. – Confirmed.

OPG – Confirmed.

Hydro Ottawa - Any issuance costs are amortized over a five-year period which is consistent with the write-off for tax purposes.

UCT 2 - Actual debt issuance costs were not requested to be included in the revenue requirement in the company’s current IR term. The unamortized debt issuance costs will be included in the calculation for the next IR term and amortized over the remaining life of the debt instrument.

Hydro One: Confirmed. As discussed in paragraph 3.6 of Exhibit F, Tab 1, Schedule 3 of EB-2021-0110 (page 11), debt issuance costs specific to each debt issue are included in the Premium Discount and Expenses column of the debt schedules and reflected in the Effective Cost Rate.

c) Concentric understands part (ii) as asking for the effective interest rate inclusive of the actual transaction costs.

Toronto Hydro:

Debenture Series	Date of Issuance	Terms (yrs)	Maturity Date	Prinicipal	Interest Rate	Issuance Costs	Effective Interest Rate	Incremental Rate
Series 17	18-Oct-2021	10	20-Oct-2031	$ 150,000,000	2.52%	$ 887,422	2.60%	0.08%
Series 18	18-Oct-2021	30	18-Oct-2051	$ 200,000,000	3.32%	$ 1,383,230	3.38%	0.06%
Series 19	13-Oct-2022	30	13-Oct-2052	$ 300,000,000	5.00%	$ 2,127,135	5.11%	0.11%
Series 20	14-Jun-2023	10	14-Jun-2033	$ 250,000,000	4.66%	$ 1,591,529	4.79%	0.13%
Series 21	12-Oct-2023	5	12-Oct-2028	$ 200,000,000	5.18%	$ 1,171,731	5.38%	0.20%

UCT 2:

Debt Issuance Cost	$5,462,938
Effective Interest Rate	NA
Incremental Rate	NA

Alectra:

Description	Lender	Start Date	Term (years)	Maturity date	Principal ($)	Issue cost	Effective Rate (%)	Coupon rate (%)	Incremental (%)
Promissory Note Payable	Alectra Inc.	4/11/2019	30	4/12/2049	$200,000,000	$1,437,541	3.50%	3.46%	0.04%
Promissory Note Payable	Alectra Inc.	2/11/2021	10	2/11/2031	$300,000,000	$1,754,325	1.82%	1.75%	0.06%
Promissory Note Payable	Alectra Inc.	11/14/2022	30	11/14/2052	$250,000,000	$1,755,955	5.27%	5.23%	0.05%
Promissory Note Payable	Alectra Inc.	6/13/2024	10	6/13/2034	$200,000,000	$1,423,855	4.72%	4.63%	0.09%

Hydro Ottawa:

Type of Debt Instrument	Date of Issuance	Term (Years)	Maturity Date	Principal ($)	Issuance Cost	Coupon Rate (%)	Effective interest rate*	Incremental amount
Promissory Note	9/Feb/15	30	2/Feb/45	$121,333,000	$786,032.67	3.639%	3.661%	0.022% Note 1
Promissory Note	25/Jun/15	10	25/Jun/25	$15,999,000	$88,067.61	2.614%	2.669%	0.055% Note 2
Promissory Note	25/Jun/15	30	25/Jun/45	$14,001,000	$91,082.12	3.639%	3.661%	0.022% Note 3
Promissory Note	16/Oct/19	10	16/Oct/29	$87,500,000	$0	2.660%	2.660%	0%
Promissory Note	16/Oct/19	30	16/Oct/49	$162,500,000	$0	3.210%	3.210%	0%

* Effective Interest rate of the actual transaction costs when amortized over the life of the debt instrument
** Actual incremental amount that was added to the issuance debt rate for transaction/issuance

1. The rate of interest payable on the principal amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.769% per annum from February 9, 2015 to February 8, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.639% per annum from February 9, 2020 to February 8, 2045.
2. The rate of interest payable on the principal amount or the amount remaining unpaid from time to time on this Promissory Note shall be 2.724% per annum from June 25, 2015 to June 25, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 2.614% per annum from June 26, 2020 to June 25, 2025.
3. The rate of interest payable on the principal amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.769% per annum from June 25, 2015 to June 25, 2020 (the first five years). Subsequently, the rate of interest payable on the Principal Amount or the amount remaining unpaid from time to time on this Promissory Note shall be 3.639% per annum from June 26, 2020 to June 25, 2045.

Hydro One:

Last 5 Debt Issuances as at August 20, 2024
Hydro One Inc.

Offering Date	Term (Years)	Maturity Date	Principal Amount ($Millions)	Coupon Rate	Yield	Premium / (Discount)	Debt Issuance Costs[1]	Effective Interest Rate	Incremental Amount
12-Dec-23	31.0	30-Nov-54	100.0	4.85%	4.56%	4.9	(0.50)	4.58%	0.029%
12-Jan-24	5.9	30-Nov-29	250.0	3.93%	4.09%	(2.1)	(0.88)	4.16%	0.068%
12-Jan-24	10.1	1-Mar-34	550.0	4.39%	4.40%	(0.3)	(2.20)	4.45%	0.049%
20-Aug-24	10.4	4-Jan-35	700.0	4.25%	4.25%	(0.3)	(2.80)	4.30%	0.048%
20-Aug-24	30.3	30-Nov-54	500.0	4.85%	4.64%	16.6	(2.50)	4.67%	0.030%

A portion of each debt issue listed above has been allocated to Hydro One Networks Inc. Distribution and Hydro One Networks Inc. Transmission

OPG:

List of last 5 debt issuances Impacting OPG's Regulated Operations as of June 30, 2024 ($M)*

Line No.	Issue	Issue Date	Term (years)	Maturity Date	Principal ($M)	Issuance Costs ($M)	Effective Interest Rate (%)	Interest (Coupon) Rate (%)	Incremental (%)
	List of last 5 debt issuances								
1	Green Bond	6/28/2024	10.0	6/28/2034	496.7	3.3	5.08%	4.83%	0.25%
2	Green Bond	6/28/2024	30.0	6/28/2054	496.2	3.8	5.17%	4.99%	0.18%
3	Green Bond	7/18/2022	10.0	7/19/2032	297.9	2.1	4.98%	4.92%	0.05%
4	Green Bond	6/22/2018	30.0	6/22/2048	417.1	3.0	3.92%	3.84%	0.08%
5	Green Bond	1/18/2019	30.0	1/18/2049	0.4	0.0	4.34%	4.25%	0.09%

*For OPG, shown are the last five public debt issuances as OPG's other debt issuances do not incur a transaction cost.

Enbridge Gas Inc:

Line No.	Issuance Date	Issuance Maturity	Term (years)	Interest Rate	Notional ($ million)	Issuance Costs ($ million)	Impact on Effective Rate	Effective Rate
1	8/17/2022	8/17/2032	10.0	4.15%	$325	$1.3	0.04%	4.19%
2	8/17/2022	8/17/2052	30.0	4.55%	$325	$1.6	0.02%	4.57%
3	10/6/2023	10/6/2028	5.0	5.46%	$250	$1.0	0.08%	5.54%
4	10/6/2023	10/6/2033	10.0	5.70%	$400	$1.7	0.04%	5.74%
5	10/6/2023	10/6/2053	30.0	5.67%	$350	$1.9	0.02%	5.69%

TAB 4

Figure 37: OEB Cost of Capital Parameter Updates

Rates Effective	Return on Equity (ROE)	Deemed Long-Term Debt Rate	Deemed Short-Term Debt Rate	Weighted Average Cost of Capital (WACC)*	Letter (Issuance Date)
Jan 1, 2024	9.21%	4.58%	6.23%	6.50%	Oct 31, 2023
Jan 1, 2023	9.36%	4.88%	4.79%	6.67%	Oct 20, 2022
Jan 1, 2022	8.66%	3.49%	1.17%	5.47%	Oct 28, 2021
Jan 1, 2021	8.34%	2.85%	1.75%	5.00%	Nov 9, 2020
Jan 1, 2020	8.52%	3.21%	2.75%	5.32%	Oct 31, 2019
Jan 1, 2019	8.98%	4.13%	2.82%	6.02%	Nov 22, 2018
Jan 1, 2018	9.00%	4.16%	2.29%	6.02%	Nov 23, 2017
Jan 1, 2017	8.78%	3.72%	1.76%	5.67%	Oct 27, 2016
Jan 1, 2016	9.19%	4.54%	1.65%	6.28%	Oct 15, 2015
Jan 1, 2015	9.30%	4.77%	2.16%	6.48%	Nov 20, 2014
Jan 1, 2014	9.36%	4.88%	2.11%	6.56%	Nov 25, 2013
May 1, 2013	8.98%	4.12%	2.07%	5.98%	Feb 14, 2013
Jan 1, 2013	8.93%	4.03%	2.08%	5.91%	Nov 15, 2012
May 1, 2012	9.12%	4.41%	2.08%	6.20%	Mar 2, 2012
Jan 1, 2012	9.42%	5.01%	2.08%	6.66%	Nov 10, 2011
May 1, 2011	9.58%	5.32%	2.46%	6.91%	Mar 3, 2011
Jan 1, 2011	9.66%	5.48%	2.43%	7.03%	Nov 15, 2010
May 1, 2010	9.85%	5.87%	2.07%	7.31%	Feb 24, 2010

Source: https://www.oeb.ca/fr/node/2122

The current timing for updates, in Concentric's view, represents a reasonable balance between the currency of the market data and sufficient advance notice to the regulated utilities and customers of the pending change to the rate of return.

LEI's Recommendation and Concentric's Response

LEI recommends:

> *Consistent with the OEB's existing policy, the OEB should continue to publish its annual cost of capital parameter updates in October or November, using 12-month trailing data as of the end of September (i.e., from October of the previous year to September of the current year), for rates going into effect in the following January.* (LEI Report, p. 152)

TAB 5

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**9**	
DATE:	**July 26, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

energy-transition risk, and second is the peer-review analysis that we undertook.

MR. YAUCH: Okay. So, as we sit here today, you would agree there is no broad electrification policy in Ontario. Correct?

MR. GOULDING: As we sit here today -- this is Mr. Goulding by the way -- yes, I would agree with that.

MR. YAUCH: So, because there is no broad policy, we don't know what is going to happen particularly in the near-term but even in the median term. There are a lot of question marks. Is there real risk that there is going to be a significant departure from the gas delivery system between now and 2028?

MR. GOULDING: This is Mr. Goulding again. You used the term "real risk," and I think one of the things that we need to be a little bit cautious about is it is not about whether you or I or Mr. Coyne personally think there is a real risk but about what the investor community perceives. I think that, you know, LEI, London Economics, and Concentric may disagree with regards to the magnitude or the degree of change among investor sentiment, but I think that there is no doubt that investors are aware of energy transition, they are aware of local proposals with regards to changes in gas utilization, and, when we look across North America, we would have to say that Ontario in terms of looking at perceived energy transition risk would fall -- and this is admittedly a subjective positioning -- would fall somewhere in the middle, perhaps slightly on the higher side with regards to energy-transition risk, just given the positions of the federal government in particular but also to a certain degree the activities of the provincial government, that we're not -- investors are not going to perceive Ontario in the same way that they perceive Oklahoma with regards to energy -- transition risk. So I do want to distinguish between my personal opinion on energy-transition risk and what I believe the investor community to perceive.

MR. YAUCH: So there Was lot of discussion yesterday -- I don't know if you listened or read the transcript; I'm not expecting you to, but -- about when the Board wants to change the equity thickness of a company, it puts a lot more weight on the near term than it does on the medium term and long term, and one economist to another, I think it is clearly because the long term has a lot more uncertainty about it. If in the near-term the risk of departures from the gas system are very low and there really isn't an energy-transition risk as we sit here looking at this application today, is there really an energy-transition risk that should be incorporated in equity thickness today if that is what the Board focuses on predominantly is the near-term?

MR. GOULDING: Well, I agree with you that this is a challenge given the way in which we think about the time periods over which we establish equity thickness and other return parameters. I think one of the benefits of Ontario is the perception -- another area in which perception perhaps differs from my own view, but -- the perception that Ontario is a relatively stable, supportive regulatory environment, and so you can say: Okay, over the near-term, energy-transition risk may be limited; we will have another kick at the can in, let's say, 5 years in the future, and, if it is increased, we as investors can have reasonable confidence that the Board is going to treat us fairly. And, historically, that has been the case when we look in the energy sector or more broadly. Investors in Ontario have been treated more or less fairly, with a few potential exceptions. That said, when we look at the fair-return standard, I think where the concern arises -- so, you know, we have looked at this and we have said, well, from a financial integrity standard, we think there are few changes. We haven't seen any real evidence today of capital attraction standard not being met. We think that, on a comparable investment standard, moving from 36 to 38 percent helps to address some concerns there. But we want to make sure that the capital attraction standard is met not just at this instant but from the standpoint of regulatory efficiency. Ideally, we don't want sometime in the next 5 years for there to be a dramatic change in the utility's ability to attract capital. When we think about investors and how they think about short-term and long-term risk, their hold periods, what they are trying to do, they are not going to just wish away long-term risk; they are going to take it into account in their investment decisions, and so, from our perspective when we look at the capital attraction standard, it is prudent to at least incorporate some thinking about long-term risk even if we believe that the energy-transition risk may be more in the -- I am just making up numbers here for example -- in the 10-year time frame versus the 5-year time frame.

MR. YAUCH: I just want to reply or ask you two questions in response to that. One is, if the Board were to approve an application for 2 or 3 years, not the full 5 years, would that change your analysis? Would you say, okay, maybe we don't need 38 percent; we need 37 percent or something? Would that reduce some of the risk? And then my second question -- I don't mean to hit you with two at once, but I'll do the second one. Does the Board need to change its sort of its policy on setting equity thickness, that it shouldn't just be near-term thing; if markets focus on long-term aspects, the Board needs to focus on long-term aspects?

MR. GOULDING: Those are both excellent questions. This is Mr. Goulding again. So I think the trade-off in doing a 2- or a 3-year approval is a matter of regulatory efficiency. I personally in terms of broader regulatory design prefer off-ramps to shorter term regulatory periods where, you know, subject to demonstration of meaningful harm, companies have the opportunity to come back for adjustments within the regulatory period.

From my perspective, just looking across the investment universe, thinking about the equity thicknesses that are observed, I think even in the case where you were

standard, the financial integrity standard and the capital attraction standard. And are you aware also that the OEB has taken the position that none of these three should be viewed in priority to the other?

MR. GOULDING: Subject to check, yes.

MR. O'LEARY: Yes. It is in the cost of capital report actually, at page 19.

MR. GOULDING: Yes.

MR. O'LEARY: Thank you. And would you agree that the legal obligation incumbent on the regulator is to consider all three components?

MR. GOULDING: Yes, subject to my previous observation about not being a lawyer.

MR. O'LEARY: Fair enough. And if I could now ask Ms. Monforton to go to Exhibit K8.3? And what we have included at page 26, PDF page 26, is a copy of the OEB's report of the Board on the cost of capital for Ontario's regulated utilities, EB-2009-0084. And if we go to page 26, Ms. Monforton, of the PDF, page 21 of the report? Yes.

You see the heading that the Board has included in the decision is "The role of the comparable investment standard." So I want to ask you a couple questions about that. If you could scroll down to the second paragraph, it states in the second sentence:

> "By establishing a cost of capital that is comparable to the return available from the application of invested capital to other enterprises of like risk..."

And if you go down a little further with the paragraph that states:

"First, 'like' does not mean the same."

So is it fair to say, Mr. Goulding, that what the OEB is saying it is a appropriate to look for the purposes of the comparable investment standard, at like business or like utilities, to understand whether or not they are comparable and therefore to use that in the standard review?

MR. GOULDING: Yes, I agree with that.

MR. O'LEARY: And then, if you go to the very last paragraph, and I won't read it all but, during the proceeding that led to this decision, there was some discussion about the applicability and the comparability of using U.S. utilities as comparators. If you go to the next page, you will see in the second line, this is a response to those parties that were arguing that U.S. utilities were not comparators, the Board said:

"The Board disagrees, and is of the view that they are indeed comparable."

And in fact, if you go to the next page, please, Ms. Monforton, the second paragraph?

"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 U.S. for guidance on regulatory issues in the province of Ontario. So I give

that to you as a bit of context.
I am wondering now if I could ask you, you do refer to it, both decisions, in your report in a number of places, but would you agree with me that, for the purposes of the Board making its decision in respect of the 2011 applications by EGD and Union at which time both sought a change in their equity ratio, that the OEB did not at that time undertake a full, fair FRS standard review?
MR. PINJANI: Are you able to rephrase the question for us?
MR. O'LEARY: Sure. Sorry, I may have mumbled that. My apologies. What I was asking you to confirm is that, if you looked at the two specific cases, EB-2011-0210 and EB-2011-0354, which were the Union Gas and Enbridge Gas Distribution decisions or applications that were made at the time and both of them were seeking a change in their equity thickness -- first of all, let me ask you that. Were you aware that -- you'll confirmed that that is what they were doing?
MR. PINJANI: Yes.
MR. O'LEARY: All right. And would you agree that the OEB looked at the threshold question about the change in business risk and determined that neither company had met the threshold and therefore they did not undertake a full, fair return standard review?
MR. PINJANI: What I'd like there if you -- I think in our review of the previous decision there were comments made by the OEB with regards to why they believed equity

ratio, an increase in equity ratio, was not justified at the time. So I am not sure whether I would say that they did not do an analysis at all or did not comment on the rationale behind why an increase in equity ratio was not justified at the time.

MR. O'LEARY: So the OEB did look at the change in the business risk as it existed back in 2012. I am happy to take you to it. In fact, perhaps I could ask Ms. Monforton to go to the PDF page 53 of Exhibit 8.3. This is the Enbridge Gas Distribution case. If you go down to the bottom where it says, "decision of the Board on equity ratio," it states:

> "The Board concludes that there has been no significant increase in Enbridge's business and our financial risk since 2007. Accordingly, the Board finds that Enbridge's equity ratio shall remain at 36 percent and that a full FRS analysis is not required."

MR. PINJANI: That is fair.

MR. O'LEARY: Sorry. I am just going to ask the question. Does that not tell us that the Board did not undertake a full FRS analysis?

MR. PINJANI: That is correct.

MR. O'LEARY: All right, and you would agree with me that the Board therefore did not undertake a comparable investment standard review back in 2012. Right?

MR. PINJANI: I would say so, yes.

MR. O'LEARY: You --

MR. PINJANI: But this goes back to the point I made earlier, I believe, with regards to what was said yesterday about OEB taking an approach which is a bit different in first trying to assess whether there is an increase in business risk and financial risk or not. If there is, then the second step is going to FRS. That has been the OEB approach as I understand it.

MR. O'LEARY: And you mentioned that earlier today, Mr. Pinjani, but that wasn't where I was going. Can I ask, Ms. Monforton, can you please go to Exhibit M2, at page 44. The heading here -- this is your report, gentlemen, and so section 4 deals with jurisdictional scan and peer-review analysis. In the middle of that, right in the middle of the first paragraph, you say:

> "London Economics has utilized a North American peer group for Enbridge Gas instead of a separate peer group for U.S. and Canadian utilities. Using North America-wide utilities deepens the sample size and provides a more meaningful reflection of the investors' opportunity space."

So let me stop there. I take it what you are saying is that, consistent with what the OEB said in its cost of capital report, you agree that it is appropriate to look at not only Canadian but also U.S. utilities of like risk. Fair?

MR. PINJANI: Yes, that is correct.

MR. O'LEARY: Thank you. And then, in the next section, scroll down, please, Ms. Monforton, under the heading "How does Enbridge Gas risk compare to similar utilities," you state:

"To develop the peer group, London Economics focused on operating companies and short-listed natural gas operating companies with an investment-grade rating."

And then you go on to say the ratings that you required. Can you go to the next page then, please, Ms. Monforton. What we see on this page is in that figure 29, is a depiction of the screening that you applied to weed out those utilities which you didn't consider to be of like risk. Is that fair?

MR. PINJANI: We short-listed the companies which were natural gas regulated, which were natural gas operating companies with an investment-grade credit rating, yes.

MR. O'LEARY: Yes, but you understood that, you know, for the comparable investment standard, the idea is for you to do a review of peer or proxy companies in Canada and the United States of like risk, and that is what your screening was intended to do, was it not?

MR. PINJANI: Yes. The investment-grade credit rating was for that purpose.

MR. O'LEARY: Okay. Great. If you go to the next page then, please, Ms. Monforton, you may need to blow this up a bit because I had trouble even reading it here, live. But let me just see if I understand. So this is your list of all of the U.S. and Canadian, we will call them, like-risk utilities. Is that correct?

taken by regulators, and I am not gathering why you believe that we have not looked at or considered the U.S. equity structures in our recommendation. By looking at the change, I believe we have considered those, and, second, when you say that the OEB did not do a full FRS analysis back in 2011, the OEB did look at change in business risk and financial risks for Enbridge Gas back in 2011, as well.

MR. O'LEARY: Sir, I didn't write your report. I was simply asking where in your report you could point me to which shows that you gave some detailed consideration to the utilities of like risk in the United States for the purposes of your recommendation. I didn't see anything other than the two sentences you have taken me to. Isn't that fair?

MR. PINJANI: I believe that is fair, but I am clarifying what analysis we undertook with regards to the change.

MR. O'LEARY: Just a couple other questions, Sir, because I think I am at the end of my time. Just in terms of energy-transition risk and electric LDCs, would you agree with me that the electric utilities in Ontario do not face the energy-transition risks that are live in this proceeding to Enbridge Gas?

MR. GOULDING: So this is Mr. Goulding. I would agree with you that the magnitude of the risks is higher for natural gas than electric utilities. I would argue that it is probably underestimated with regards to electric utilities, but we are not talking about existential risks

TAB 6

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British Columbia
Utilities Commission

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British Columbia Utilities Commission

Generic Cost of Capital Proceeding

(Stage 1)

Decision
and Order G-236-23

September 5, 2023

Before:
D. M. Morton, Panel Chair
A. K. Fung, KC, Commissioner
K. A. Keilty, Commissioner
T. A. Loski, Commissioner

Table 39: Capital Structure and ROE for FBC[709]

	Recommended Equity Component	Recommended ROE	Recommended Weighted ROE
ICG	38.50%	8.80%	3.39%
BCOAPO	40.00%	9.50%	3.80%
The CEC	40.00%	9.56%	3.82%
RCIA	40.00%	8.00-8.75%	3.20-3.50%

The following summarizes FortisBC's reply as it relates to interveners' submissions on the utilities' recommended capital structure, overall ROEs and/or the interplay between those two concepts.

ICG

With respect to ICG's submission, FortisBC highlights ICG's internal inconsistent reasoning to reach its low result:

i) On the one hand, ICG agrees that the BCUC should give the greatest weight to the North American proxy group when determining the ROE, which is, "no doubt, influenced by the fact that this tends to reduce FBC's ROE significantly relative to using the Canadian proxy group"; and

ii) On the other hand, ICG does the opposite to determine the common equity ratio as it advocates using the simple Canadian utilities median of 38.75 percent equity, rounded down without explanation to 38.5 percent, and giving "no weight" to the same U.S. proxy group companies that ICG advocates using for the ROE calculation. As the North American electric proxy group has an average equity ratio well above FBC's proposed equity ratio, ICG's approach tends to suppress the common equity ratio as well. FortisBC stresses that ICG's differing approaches are internally inconsistent because the common equity ratio and ROE and intertwined; ROE determinations are affected by the common equity ratio, and *vice versa*. FortisBC remarks that all the October 2022 ROE calculations based on the North American proxy group, which ICG wants to use, assume that the BCUC has accepted FBC's proposed common equity ratio of 40 percent. Even then, the U.S. electric proxy companies still have about 10 percent thicker equity on average (49.7 percent), such that the differential with the North American electric proxy group is substantial. FortisBC submits that FBC's ROE would be even more understated if the BCUC were to accept ICG's position of 38.5 percent equity. Applying a Hamada adjustment to the Lesser CAPM Results (30-day average stock prices and interest rates) for the North American proxy group at 38.5 percent equity increases the estimated ROE by 35 bps to 7.95 percent.[710]

Finally, FortisBC points out that ICG has not accounted for any size premium for FBC and offers no explanation for it. FortisBC stresses that both experts agree that the CAPM will understate ROE results for companies like FBC that are smaller than the proxy companies and reiterates that the size premium calculated by Mr. Coyne based on the Duff & Phelps approach is 105 bps.[711]

---

[709] ICG Final Argument, pp. 16,15, BCOAPO Final Argument, pp. 70, 58, The CEC Final Argument, pp. 51, 43, RCIA Final Argument, pp. 31, 35. Recommended weighted ROE calculated by the BCUC.

[710] FortisBC Reply Argument, pp. 55–56.

[711] Ibid., p. 55.

BCOAPO

With respect to BCOAPO's submission, FortisBC notes that BCOAPO endorses an ROE of 9.5 percent for both FEI and FBC, on 40 to 42 percent and 40 percent equity, respectively, inclusive of a 50-bps adjustment for flotation and financial flexibility, an adjustment for FEI and FBC's lower equity thickness, and a size premium for FBC. FortisBC states that BCOAPO's recommendations acknowledge that the cost of capital has increased since the BCUC last set FEI and FBC's respective ROEs but that BCOAPO's calculations still understate the required ROE due to its reliance on an implausibly low Lesser CAPM result and mathematical errors.[712] FortisBC states that the latter error skews BCOAPO's results downward significantly.[713]

Based on BCOAPO's methodology, FortisBC demonstrates how BCOAPO's recommended CAPM ROE should have been calculated as 9.51 percent instead of 9.01 percent, an error which carries forward when BCOAPO averages the CAPM and Multi-Stage DCF model results. The correction of BCOAPO's mathematical error in the overall average of BCOAPO's proposed CAPM and multi-stage DCF model for the BCOAPO-revised North American electric proxy group increases BCOAPO's ROE result from 9.04 percent to 9.29 percent.[714]

Furthermore, as noted in Section 5.2.2, FortisBC submits that the 12-bps upward adjustment for FEI that BCOAPO adds to account for its thinner proposed equity than the 45 percent basis for all the ROE model calculations is clearly insufficient. Applying a Hamada adjustment to Mr. Coyne's CAPM results for the BCOAPO-revised North American proxy group at 42 percent equity increases BCOAPO's estimated ROE by 45 bps. FortisBC submits that the ROE increase would be even larger at 40 percent (i.e. the lower end of the BCOAPO's recommended range for FEI's equity thickness).[715] Finally, FortisBC submits that BCOAPO miscalculates FBC's size premium and correcting that error alone yields an ROE of more than 10 percent. Indeed, FortisBC submits that the proper 105-bps size adjustment alone would increase BCOAPO's calculated ROE for FBC to approximately 10.09 percent, assuming 40 percent equity.[716]

The CEC

With respect to the CEC's submission, FortisBC stresses that the CEC's significant concessions, in terms of increased equity thickness and ROE for FEI and increased ROE for FBC, are indicative of the overwhelming body of evidence demonstrating that the cost of equity has increased since the BCUC last considered FEI and FBC's respective ROEs. However, FortisBC views the CEC's recommended ROEs as being understated in two respects.

The first relates to the 80-bps deduction which accounts for most of the difference between the CEC's and Mr. Coyne's respective recommendations. The second relates to the interplay between equity thickness and ROE. FortisBC points out that the modelling underlying the CEC's recommendations for FEI is premised on a 45 percent common equity ratio, but the CEC is recommending a 40 percent ratio. FortisBC states that both experts confirm that increasing the disparity between FEI's equity ratio and that of the proxy group will increase the required ROE. FortisBC points out that Mr. Coyne chooses not to include a Hamada adjustment to his CAPM results only because he also recommends to increase FEI's equity ratio to 45 percent, thus significantly

[712] FortisBC Reply Argument, p. 44.
[713] Ibid., p. 45.
[714] Ibid., p. 46.
[715] FortisBC Reply Argument, p. 46.
[716] Ibid., p. 47.

narrowing the equity disparity with the gas proxy groups. But FortisBC states that this logic will no longer hold at the CEC's recommended 40 percent equity for FEI and applying a Hamada adjustment to Mr. Coyne's CAPM results for the North American gas proxy group at 40 percent equity would increase the estimated ROE for FEI by 48 bps to 10.78 percent.[717]

RCIA

With respect to RCIA's submission, FortisBC points out that RCIA arrives at its proposed ROEs of 8.00 percent to 8.75 percent for both FEI and FBC by ignoring the Multi-Stage DCF model (and the higher results[718]) altogether, by applying unsupported downward adjustments to Mr. Coyne's CAPM results, by ignoring the most current data, and by failing to account for differentials in financial risk and size premium. FortisBC submits that updating RCIA's own calculations to reflect October 2022 data alone significantly closes the gap with Mr. Coyne's recommendations, and rectifying other shortcomings brings them further into alignment.[719]

As explained in Section 5.2.5, with the first adjustment, RCIA's CAPM-based ROE would increase to 9.43 percent, which is significantly higher than its proposed 8.00 percent to 8.75 percent. Averaging this 9.43 percent with the Multi-Stage DCF model results for the Canadian proxy group of 10.46 percent based on October 2022 data would result in an ROE of 9.94 percent for both FEI and FBC. FortisBC submits that these values support Mr. Coyne's recommendations of 10.1 percent on 45 percent common equity for FEI and 10.0 percent on 40 percent common equity for FBC.[720] Then, applying a Hamada adjustment to RCIA's own CAPM calculations, updated to October 2022 data for the Canadian proxy group at 40 percent equity, would increase the estimated ROE for FEI and FBC by 47 bps to 9.90 percent.[721] And adding a size premium for FBC, which Mr. Coyne calculates at 105 bps based on Duff & Phelps data, would further increase the CAPM ROE for FBC.[722]

Overall Panel Determination on Capital Structure and ROE

Deemed Equity Component

FortisBC proposes an equity thickness of 45.0 percent for FEI and 40.0 percent for FBC, while interveners recommend 40.0 percent to 42.0 percent for FEI and 38.5 percent to 40.0 percent for FBC. Mr. Coyne observes that his recommended 45.0 percent equity ratio for FEI is the approximate midpoint between the average equity ratio of Canadian investor-owned gas distribution companies and US gas distribution companies.

While the Panel views the 37.0 percent to 53.4 percent equity thickness of comparable Canadian and US gas utilities (see Table 36 above) as a possible range of equity thickness for FEI, this does not imply that any point within the range will meet the Fair Return Standard. The Panel is not convinced that determining a deemed equity component can be done in a precise manner such as taking an average between certain numbers. A capital structure that is optimal for FEI or FBC may not be optimal for other utilities. The Panel must assess the business risk, financial risk, and other items such as accounting for differences in leverage in the proxy group

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717 FortisBC Reply Argument, pp. 43–44.

718 The Multi-Stage DCF model results are higher than the CAPM results based on October 2022 data, not December 2021 data.

719 FortisBC Reply Argument, p. 47.

720 FortisBC Reply Argument, pp. 50–51.

721 9.43% + 0.47% = 9.90%.

722 FortisBC Reply Argument, p. 51.

companies used in the modelling (e.g. a Hamada adjustment in the CAPM results) and allowing for financial flexibility, all of which may be difficult to quantify when estimating the required equity component.

Further, Mr. Coyne's "midpoint" observation does not align with his recommendation for FBC's deemed equity ratio of 40.0 percent, where the Canadian electric average is 39.42 percent and the US electric proxy group average is 49.76 percent as shown in Table 37 above.

Throughout this decision, the Panel notes that certain factors should be considered as part of the capital structure determination, namely:

- Compensation to the shareholder for the business and financial risks of FEI and FBC (Sections 4.2 and 4.3).
- The approach to addressing the discrepancy in financial risk through an adjustment to the capital structure (Section 5.2.2).
- Consideration of financial flexibility to the extent that it is required for FEI and FBC to have spare borrowing capacity. However, Mr. Coyne submits that financial flexibility is not necessary if the regulator establishes comparable equity ratios in the 50 percent to 52 percent range and comparable ROEs in the 9.5 percent to 10.0 percent range (Section 6.2.2).
- Benefits of maintaining the current credit ratings of FEI and FBC (Section 4.1).

In Section 4 of this decision, we assess how business risk has changed since 2016 for FEI and 2013 for FBC from the perspective of their shareholder and investors. We discuss that Energy Transition risk for FEI is a real shareholder risk in Section 4.2, while other increased risk categories are largely borne by ratepayers. Overall, an increase in FEI's equity component is warranted to compensate for the increased risks faced by FEI's shareholder and investors.

The Panel recognizes that Dr. Lesser describes business risks to be generally reflected in the determination of the allowed ROE because financial risks are most directly related to a firm's capital structure, credit rating, and cost of debt. However, there is no supporting evidence for his view. In contrast, Mr. Coyne's view is that there is a need to adjust either the capital structure or the ROE. Therefore, it follows that regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met.

For practical reasons, given the inter-relationship of all these factors, the Panel will continue the approach of reflecting changes in business risks as adjustments to the capital structure, recognizing that it will also impact the ROE. This approach is consistent with past BCUC decisions and provides room for the exercise of informed judgment.

In determining the optimal capital structure for FEI, the only expert evidence is Mr. Coyne's recommendation of 45.0 percent and his cost of capital analysis is largely built around this 45.0 percent equity thickness. Further, Mr. Coyne chooses not to make Hamada adjustments to his own CAPM results because his recommended common equity ratio of 45.0 percent for FEI would "significantly narrow the equity disparity with the gas proxy group."[723] The Panel agrees that any deviation from a 45.0 percent equity thickness, for example, setting FEI's equity thickness at the 40.0 percent to 42.0 percent range, may warrant a corresponding impact on the allowed ROE.

In the absence of contrary expert evidence and recognizing that FEI shareholder's real business risks, such as the impacts from the Energy Transition risk have increased since 2016, we accept Mr. Coyne's recommended 45.0 percent equity thickness for FEI. The Panel finds that the 45.0 percent equity thickness meets the comparable investment and capital attraction requirements in the Fair Return Standard because 45.0 percent is premised on FEI's proxy group and supported by our assessment of FEI's business risk. Further, as compared to FEI's current 38.5 percent equity thickness, an increase to 45.0 percent will maintain FEI's financial integrity.

The Panel now turns to financial leverage and financial flexibility. The Hamada adjustment and financial flexibility are partially related. The objective is to harmonize FEI and FBC's financial leverage to be comparable with peer proxy companies. For FEI, we acknowledge that 45.0 percent meets the Fair Return Standard and is supported by business risk assessment, comparable investments, and expert recommendation. In our view, a 45.0 percent equity component forms an optimal capital structure based on the evidence in Stage 1.

Further, since FortisBC's own expert acknowledges that 45.0 percent would "significantly narrow" the equity disparity and bring FEI's equity thickness towards the 50.0 percent to 52.0 percent range applicable to its proxy group, the Panel is not persuaded that increasing FEI's equity thickness beyond 45.0 percent to incorporate a further adjustment for financial flexibility or ring-fencing is required in order to meet the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FEI is 45.0 percent.**

For FBC, we note that FortisBC's proposed 40.0 percent equity thickness and interveners' positions are mostly aligned. Mr. Coyne also recommends 40.0 percent equity thickness for FBC. However, ICG submits that the BCUC should set FBC's equity thickness at 38.5 percent, which is based on the Canadian Electric median of 38.75 percent and submits that FBC's business risks are lower since 2013.[724] The Panel agrees with FortisBC that ICG's final arguments are unclear because on one hand, ICG submits that "the BCUC should place the greatest weight on the North American proxy group results"[725] but on the other hand, "the US proxy group should be no weight when determining FBC's equity ratio."[726] Therefore, we place no weight on ICG's recommendation to set FBC's deemed equity thickness at 38.5 percent.

As discussed in Section 4.3, the Panel finds that FBC's business risk overall has not changed materially since 2013. The Panel views that business risk assessment of FBC should be the primary factor to the determination of a fair capital structure. This is because we see that financial impacts, in part, result from our decision on the deemed capital structure. FBC has managed to maintain its current credit rating since 2013 at 40.0 percent equity thickness. Therefore, we find that no change in FBC's equity component within its current capital structure is warranted to reflect no material changes in its business risk.

Notwithstanding these findings, the Panel now needs to consider financial leverage and financial flexibility for FBC to determine whether any upward adjustment to its 40.0 percent equity thickness is warranted. FortisBC

[723] FortisBC Reply Argument, p. 43.
[724] ICG Final Argument, pp. 3–4.
[725] Ibid., p. 10.
[726] Ibid., p. 16.

and Mr. Coyne are not recommending any capital structure changes for FBC and have not explicitly recommended a size premium in the CAPM analysis for FBC.

While 40.0 percent equity thickness is in line with the Canadian electric utility average of 39.42 percent, it is much lower than the US electric proxy group average of 49.76 percent. We accept Mr. Coyne's observation that his FBC recommendation is in line with FBC's current risk profile, but not within the range of its US peers. In light of our decision to consider financial leverage and financial flexibility in the capital structure, we find that a modest upward adjustment in equity thickness of 1.0 percent for FBC is warranted to conform with the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FBC is 41.0 percent.**

Return on Equity

The Panel is persuaded by Dr. Lesser's view that, in addition to being anchored in financial theory and being transparent, models used by regulators to set the cost of capital for regulated utilities should ideally minimize reliance on subjective factors. Dr. Lesser states that 'subjective' adjustments to model results are those made without any underlying basis in financial theory and no empirical support, and he advises against these types of adjustments, as they can undermine confidence that the resulting allowed ROE values are 1) just and reasonable and 2) consistent with reasonable decision-making.

Previously in this decision, the Panel made certain determinations that are departures from, namely the 2013 and 2016 BCUC cost of capital decisions. One change worth highlighting is the Panel's determination to use North American proxy groups, based on a finding that using North American data, consisting of a reasonable mix of both Canadian and US comparators, is superior to using either Canadian proxy groups or US proxy groups alone.

Furthermore, the Panel accepts Mr. Coyne's beta estimates, which are Blume-adjusted, noting that both experts in this proceeding favour the use of Blume-adjusted betas and that none of the parties object to their use. The Panel is also reassured to see that empirical evidence exists to show that the Blume adjustment is applicable to all betas, ranging from a low of 0.50 to a high of 1.53. The Panel recognizes that the use of Blume-adjusted betas is a departure from the previous two BCUC cost of capital decisions and has the effect of increasing the CAPM ROE as the Blume-adjusted betas for Mr. Coyne's North American proxy group average 0.86, compared to a BCUC-accepted beta of 0.60 in the 2013 and 2016 Decisions.

Also, the Panel finds that it is appropriate to consider forward-looking estimates in determining the MRP and to base that forward-looking MRP on the Constant DCF model, which has been given equal weighting to the historical MRP. These determinations are also departures from previous BCUC decisions. In particular, the 2016 Decision placed more weight on historical MRP estimates than on the forward-looking ones and no weight on the DCF estimates of the forward-looking MRP (constant growth or Multi-Stage DCF). The Panel acknowledges that these determinations also increase the CAPM ROE relative to placing more weight on historical MRP or to using the Multi-Stage DCF model to estimate the forward-looking MRP.

Beyond these findings, the Panel takes the approach of making determinations that have a sound basis in financial theory, that are transparent and easily replicated, with minimal 'subjective' adjustments. The Panel agrees with Dr. Lesser and finds it preferable to get the allowed ROE value right based on the models rather than adjusting the allowed ROE after the fact, such as adding adders for financial flexibility and flotation costs or considering other adjustments as suggested by some interveners.

To balance the fact that pure market-based models like the DCF model and CAPM tend to get whipsawed by volatile conditions in the market, which characterized much of the period during which evidence was filed in this proceeding, the Panel finds that relying on more models than just the CAPM and Multi-Stage DCF is especially important. Accordingly, the Panel determined earlier in this decision that considerable weight should also be given to the use of the Risk Premium Model, instead of simply using it as a reasonableness check as Mr. Coyne advocates.

Ultimately, the Panel finds that assigning an equal weighting to each of the three models is appropriate for the following reasons: 1) the Panel sees merit in all three models, recognizing their respective strengths and weaknesses, and behaviour under different market conditions; 2) the Panel would be hard pressed to say that one model is fundamentally superior to the others; and 3) the Panel sees no compelling reason to give anything other than equal weighting to each of the three models.

The following table summarizes the Panel's previous individual determinations related to the ROE estimates based on the CAPM, Multi-Stage DCF model, Risk Premium Model, and the flotation costs and financial flexibility adders to arrive at its ROE determination for FEI and FBC, respectively.

Table 40: Allowed ROE for FEI and FBC

Models	Revised North American Gas Proxy Group	Revised North American Electric Proxy Group
CAPM – excluding flotation costs and financial flexibility adder (see Section 5.2.5)	9.90%	9.77%
Multi-Stage DCF model – excluding flotation costs and financial flexibility adder (see Section 5.3.3)	8.93%	8.99%
Flotation costs and financial flexibility adders for the CAPM and Multi-Stage DCF models only (see Section 6.2)	0.00%	0.00%
Risk Premium Model (see Section 5.4.3)	10.12%	10.16%
Average of all three models	**9.65%**	**9.64%**

From a purely mathematical standpoint, FEI would have an allowed ROE that is 1 bps higher than FBC. However, the Panel does not view that such differentiation in allowed ROE is warranted. The difference in utility characteristics is already reflected in the deemed capital structure for FEI and FBC. **The Panel finds that an allowed ROE of 9.65 percent for each of FEI and FBC will meet the Fair Return Standard based on the evidence examined and submissions received in Stage 1.**

For the reasons stated above, the Panel determines the following:

- **For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and**
- **For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.**

The Panel accepts that permitting requirements are changing, which may lead to higher costs related to FEI's ongoing operating and maintenance activities and its larger construction projects. However, FEI did not present evidence that these changing requirements have resulted in expenditures for which it has not received approval to recover from its customers.

FEI also submits that other unexpected events, such as more frequent extreme weather events and increased incidences of cyberattacks, can impact its ability to maintain and operate its system, thereby increasing operating risk. The Panel agrees with FEI that it is not necessary to demonstrate that each risk factor will impede FEI's ability to achieve its ROE. Rather it is incumbent upon FEI to demonstrate that investors perceive a long-term risk of its ability to recover investments. FEI did not present evidence that demonstrates that investors view these risks as being greater for FEI than for other utilities, nor did FEI provide evidence demonstrating that it has been unable to recover its incurred expenditures needed to address these operating risks. Based on the foregoing, the Panel is not persuaded that FEI's overall operating risk has increased for its shareholder since 2016. **The Panel finds that FEI's operating risk is similar to what it was in 2016**.

Regulatory

FEI argues that its overall regulatory risk is higher than what was assessed in the FEI 2016 COC proceeding. FEI submits that regulatory uncertainty gives rise to the risk that the allowed return or rates may not meet the Fair Return Standard, or that necessary investments are not approved. However, FEI provides no evidence that regulatory uncertainty has led to an increase of perceived risk from investors or rates being set at a level that does not provide FEI an opportunity to earn its allowed return. The Panel agrees with the CEC that "the 'lack of assured approval' should not be equated with significant risk."

FEI submits that risk associated with regulatory lag and ultimate approval of cost recovery has also increased since 2016 when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title. While the Panel accepts that these requirements have become more onerous since 2016, FEI provides no evidence that these changing requirements have resulted in expenditures for which FEI has not received approval to recover from its customers nor is this risk perceived by investors to be higher for FEI than for other utilities.

With respect to FEI's submission that the BCUC's decision to consider that a more generic approach to deferral account financing treatment results in increased regulatory risk, no decision has yet been reached. The Panel agrees with BCOAPO that FEI (and FBC) will have a full opportunity to present their views in an open and transparent proceeding before the BCUC before any decision is made. Therefore, the Panel is not persuaded that FEI's overall regulatory risk has increased for its shareholder since 2016. **The Panel finds that FEI's regulatory risk is similar to what it was in 2016.**

Overall Business Risk

Interveners generally agree with FEI that its overall business risk has increased, but to a lesser degree than submitted by FEI. The CEC submits that FEI has a key risk in the Energy Transition, but that many of the other risks are overstated,[263] and recommends that the BCUC find FEI's business risk to be slightly higher than in

[263] The CEC Final Argument, p. 9.

2016.[264] RCIA submits that the perception of FEI risk appears to be higher today than it was in 2016, but states that FEI exaggerates the magnitude of such differences.[265] RCIA submits that given the absence of clear, objective evidence validating an absolute increase in business risk, RCIA opposes increasing FEI's equity thickness to the level requested by FEI.[266] BCOAPO agrees that FEI's business risk has increased since the FEI 2016 COC proceeding; however, it does not view FEI's business risk as having increased to the degree suggested by FEI.[267]

Given the findings discussed above associated with the changes in FEI's business risks to the shareholder, **the Panel finds that FEI's overall business risk has increased since 2016.** That increase is most significantly attributable to the increase in political risks associated with the Energy Transition and the cumulative effect of the perceived risks in Indigenous Rights and Engagement, energy price, and demand/market risks that could shift the risk to the shareholder if the utility is no longer viewed as an attractive investment by investors.

The Panel will address the impact of the increased business risk on FEI's capital structure and ROE, which are also influenced by factors beyond business risk, in Section 6.3 below (Overall Capital Structure and ROE).

4.3 FBC Business Risk

Unlike FEI, FBC's business risk was last assessed in the BCUC 2013 GCOC - Stage 2 proceeding.[268] In FortisBC's evidence, FBC provides an overview of its business risks across nine categories: four of which it considers to be of similar risk-level since 2013, with four categories considered to be of higher risk and only one considered to be lower.

FBC used similar categories as in the 2013 GCOC proceeding, other than the Indigenous Rights and Engagement risk factor. It was previously subsumed under political risk but has now been promoted to its own risk category. Additionally, the operating risk category has new risk factors: Project Resistance and Cybersecurity.[269] FBC summarizes its risk in the GCOC proceeding as "being similar to what was assessed in the 2013 Proceeding."[270] FortisBC prepared Table 10 below summarizing this risk assessment.

[264] The CEC Final Argument, p. 28.
[265] RCIA Final Argument, p. 31.
[266] RCIA Final Argument, p. 31
[267] BCOAPO Final Argument, p. 25
[268] Exhibit B1-8, p. 2
[269] Exhibit B1-8-1, Appendix B, p. 1.
[270] Ibid.

TAB 7

Alberta Utilities Commission

Determination of the Cost-of-Capital Parameters in 2024 and Beyond

October 9, 2023

were addressed by the screening criterion, which excluded utilities from the comparator group if less than 80 per cent of their assets are tied to rate-regulated activities.

103. While the Commission finds that the U.S. companies have higher business risks than the Alberta utilities, for the purpose of establishing the comparator group, the Commission accepts the utilities' evidence that it is appropriate to include U.S. utility holding companies. The reasons for this are: (i) the relatively limited number of publicly traded Canadian utility companies; (ii) the prevalence of U.S. business operations among many publicly traded Canadian utilities; and (iii) investors' tendency to consider utility investment opportunities in both the U.S. and Canada.[97] Further, the Commission remains of the view that it is reasonable to consider the U.S. market return data given the globalization of the world economy and integration of North American capital markets.[98] Notwithstanding these findings, none of the Alberta utilities raises capital directly in the equity market, or operates outside of Alberta unlike a number of companies in the comparator group, which are holding companies and can operate anywhere.

104. After considering the evidence presented in this proceeding, the Commission acknowledges the utilities in the comparator group are not identical to the Alberta utilities, but concludes they are sufficiently comparable for use in various financial models. However, and as set out in in this section and Section 6.4.5, the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities. Accordingly, the Commission retains the view expressed in the 2018 GCOC decision that a significant amount of judgment must be applied by the Commission when interpreting data from the representative utilities to establish the ROE required by investors in the Alberta utilities.[99]

6.3 Measure of the risk-free rate

105. The risk-free rate is an important component of ERP models, such as the CAPM, and the formulaic approach approved by the Commission in Section 5. ERP-based models are based on the fundamental assumption investors require higher returns for bearing higher risk; or, in other words, investors require a premium for bearing risk that exceeds the risk-free rate. The Commission has accepted in the past that there is an inverse relationship between the risk-free rate and the risk premium required by equity investors: as interest rates increase (decrease), risk premium decreases (increases).

106. Consequently, given these fundamental relationships inherent in ERP-based models, the risk-free rate of 3.10 per cent approved in this section is used for three purposes in this decision: (i) as a base forecast long-term GoC bond yield (YLD_{base}) against which future expected changes in risk-free rates are measured to adjust the ROE in accordance with the approved formula; (ii) as a factor to determine the base ERP underlying the approved formula; and (iii) a measure of the risk-free rate in the CAPM model used to estimate the notional ROE.

107. Consistent with past GCOC proceedings, parties uniformly submitted that yields on long-term government bonds are considered to be default free and therefore are an appropriate measure of the risk-free rate. There was general agreement the 30-year Canada bond yield be

97 Exhibit 27084-X0937, Utilities reply argument, PDF page 12, paragraph 32.
98 Decision 22570-D01-2018, paragraph 275; Decision 20622-D01-2016: 2016 Generic Cost of Capital, Proceeding 20622, October 7, 2016, paragraph 302; Decision 2009-216, paragraph 200.
99 Decision 22570-D01-2018, paragraph 275.

used, as the 30-year term to maturity is consistent with the long-term character of the underlying utility assets.

108. Parties were also consistent in the view that the bond yield used to approximate the risk-free rate be forward-looking, in keeping with the forward-looking nature of a cost-of-capital determination. However, there were differences in how the forecast 30-year Canada bond yield should be determined and the data sources used. Submissions of parties as to the forecast long-term GoC bond yield, term to maturity, and source of data are summarized below in Table 1.

Table 1. Risk-free rate recommendations

Witness (sponsoring party)	Recommendation	Data source	Yield
Dr. Villadsen (ATCO/Apex/Fortis)	Use projection of the 10-year Canada bond yield plus the long-term average maturity premium between 10-year and 30-year Canadian bonds.[100]	Consensus Economics[101]	3.85% as of November 7, 2022[102]
Concentric (ENMAX)	Use 10-year bond yield forecast and add the average spread between 10- and 30-year government bond yields.[103]	Consensus Economics	3.59%[104]
D. D'Ascendis (AltaLink/EPCOR)	Use an average of three-month-out and 12-month-out forecasts of the 30-year Canada bond yield.[105] [106]	RBC Financial Markets Monthly and TD Economics Forecast	2.89% as of December 31, 2022
D. Madsen (IPCAA)	Use current 30-year GoC bond yield as this point in time observation is consistent with a number of published forecasts of the 30-year Canada bond yield for 2023-2024.[107]	RBC Financial Markets Monthly, Kroll	2.95% as of January 13, 2023
Dr. Cleary (UCA)	Use the actual prevailing 30-year government bond yield at the time the initial (or base) ROE is set.[108]	-	2.85% as of January 19, 2023[109]
J. Thygesen (CCA)	No submission made on the rate or approach to quantify this variable.	-	Maximum risk-free rate for 2024 be set at 3%[110]

109. The Commission accepts the submissions of parties that the 30-year term to maturity best reflects the long-term character or useful life of the underlying utility assets. The Commission

100 Exhibit 27084-X0469, PDF page 71.

101 Consensus Economics publishes long-term [10-year] interest rate projections twice a year, in April and in October. Transcript, Volume 2, page 114, lines 2-6.

102 Exhibit 27084-X0469, PDF page 41. 3.85% represents the average of yield on a 10-year Canadian government bond in February 2023 (3.5%) and November 2023 (3.4%) as reported by Consensus Forecasts on November 7, 2022, publication, adjusted upwards by Dr. Villadsen by 40 basis points to represent maturity premium for the 30-year over the 10-year Canadian government bond.

103 Exhibit 27084-X0315, PDF page 101.

104 Exhibit 27084-X0315, PDF page 61, Concentric evidence. While Concentric did not recommend a specific numerical value for the base forecast long-term GoC bond yield, it used an average of the Canadian (3.59%) and U.S. (3.87%) risk-free rates of 3.73% in its estimation of the notional ROE and implied ERP in its filed evidence.

105 Exhibit 27084-X0390, PDF page 24.

106 Exhibit 27084-X0610, AML_EPCOR-AUC-2023FEB21-001, PDF pages 1-3.

107 Exhibit 27084-X0292, PDF page 14.

108 Exhibit 27084-X0320.02, PDF pages 6-7.

109 Exhibit 27084-X0605, UCA-AUC-2023FEB21-012, PDF page 31.

110 Exhibit 27084-X0713, paragraph 44.

notes that parties provided various empirical and capital markets resources that supported the rationale for matching the useful life of the asset and the term to maturity of the risk-free rate.[111]

110. In keeping with the prospective or forward-looking nature of the determination of the cost of capital and prior Commission practice, it is appropriate to use a forecast of the 30-year Canada bond yield submitted on the record of this proceeding. The Commission finds that a direct forecast of the 30-year Canada bond yield from Canadian major banks is simpler and more transparent than the approach recommended by Dr. Villadsen and Concentric, which uses the Consensus Economics forecast 10-year GoC bond yield and adjusts it by adding the average spread between 10- and 30-year government bonds. The need for this adjustment arises from the fact that Consensus Economics, on which Dr. Villadsen and Concentric rely, does not publish a forecast for the 30-year Canada bond yield. Similar adjustments have been used by the OEB and EUB for their formulas because of reliance on Consensus Forecasts.

111. The 30-year Canada bond yield forecasts are published by large, reputable Canadian financial institutions such as “the Big Six” banks. In the Commission’s view, these forecasts are of comparable quality to the forecasts published by Consensus Economics. In fact, the Consensus Economics forecast is an average of estimates from various sources, including Canadian major banks. However, using direct forecasts of the 30-year Canada bond yield eliminates the need to make additional estimates and adjustments to the 10-year forecast for which there is no single, standardized approach. In addition, these forecasts are publicly available without cost. For simplicity, the Commission considers that averaging the forecasts from three banks, RBC, TD and Scotiabank, is sufficient. Should a forecast from one or more of these banks be unavailable, there are three additional major banks from which a forecast may be obtained as a substitute.

112. In addition to relying on bond yield forecasts published by the three banks, the Commission accepts in principle the approach of D. Madsen and Dr. Cleary to use a naïve forecast,[112] using the actual 30-year GoC bond yield to inform an estimate of the future 30-year GoC bond yield. The Commission has relied on this approach in past GCOC decisions to temper published forecasts because it accepted they tend to overestimate changes in interest rates. In this proceeding, representatives of customer groups made a similar point.[113] However, the Commission considers it is better to use the average actual long-term GoC bond yields for an entire month rather than the yield that prevailed on any a single day in that month, as was done by Dr. Cleary and D. Madsen, to smooth out the daily volatility.

113. The Commission will use the bank forecasts published in February 2023 provided by D. D’Ascendis, as they were the most recent bank forecasts of long-term GoC bond yields provided on the record. For consistency, the Commission will use the average actual long-term GoC bond yield in February 2023 for the naïve forecast.

114. For the reasons above, the Commission finds it reasonable to set the forecast risk-free rate to be 3.10 per cent, equal to the average of the 30-year Canada bond yield estimates for the forecast period Q1 2023 to Q4 2023 of RBC at 2.90 per cent, TD at 3.08 per cent, and

[111] Exhibit 27084-X0390, D’Ascendis evidence, PDF pages 22-24.

[112] An estimating technique wherein the actual values from the previous period are employed as the forecast for the current period, without adjusting them or identifying causal factors.

[113] Exhibit 27084-X0292, Evidence of Dustin Madsen, PDF page 14; Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 39.

Scotiabank at 3.26 per cent as of February 2023[114] as well as a naïve forecast of 3.16 per cent representing the average actual long-term GoC bond yield for the period February 1 to February 28, 2023.[115]

6.4 Notional ROE

115. In this section, the Commission determines the notional ROE of 9.0 per cent using current market data and considering results of well-known and widely accepted empirical models to estimate the required return such as the CAPM, constant growth discounted cash flow (DCF), and multi-stage DCF.

116. Under the formulaic approach, the notional ROE serves as the base metric against which future adjustments arising from changes in forecast long-term Canada bond yields and utility bond yield spreads are made and captures the estimated forecast ERP that is commensurate with the base forecast long-term GoC bond yield.[116] In turn, the notional ROE can be defined as the sum of the base forecast long GoC bond yield (YLD_{base} in the formula) and the base forecast ERP.

117. Parties recommended a notional ROE and estimated the ERP based on their respective risk-free-rate submissions. Table 2 sets out the notional ROE and ERP recommendations by party.

Table 2. Notional ROE and ERP recommendations by party

Witness (sponsoring party)	Notional ROE (%)	ERP[117] (%)	Empirical approaches used	Comments
Dr. Villadsen (ATCO/Apex/Fortis)[118]	10.0	5.68	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommended range for notional ROE is 9.2% to 10.4%
Concentric (ENMAX)	9.50	5.67	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommendation reflects M-DCF and CAPM using historical MERP.[119]
D. D'Ascendis (AltaLink/EPCOR)	10.30	6.44	CAPM/ECAPM, DCF, M-DCF, Predictive Risk Premium Model, Adjusted Total Market Approach	Recommended range for notional ROE is 9.80% to 10.80%.[120]
D. Madsen (IPCAA)[121]	7.70	4.75	CAPM, DCF and M-DCF	Recommendation is simple average of CAPM and DCF models (7.51% and 7.90%)
Dr. Cleary (UCA)	6.75	3.90	CAPM, DCF, M-DCF and Utility Bond Risk Premium Analysis	-

114 Exhibit 27084-X0610, PDF page 2 with reference to Exhibit 27084-X0611 providing supporting data.
115 This is a Commission calculation using the Bank of Canada website provided in Exhibit 27084-X0613, UCA-UTILITIES-2023FEB21-008, PDF page 11. https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010013901
116 Exhibit 27084-X0268.01, PDF page 3.
117 Includes 0.50% flotation allowance.
118 Exhibit 27084-X0921, PDF page 2. Recommendation also assumes 40% deemed equity for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, with additional equity thickness for ATCO Electric Transmission (42%), Apex (44%) and Fortis (43%). If deemed equity is set at 37%, then the ROE should be set 25 to 40 basis points above the recommendation for 40% equity or 10.25% to 10.40%. Recommended notional ROE and VAR3 include 20 basis point risk adder.
119 Exhibit 27084-X0315, PDF page 4. If deemed equity is set at 40%, then the ROE should be set at 10%.
120 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 9.
121 Exhibit 27084-X0292, PDF page 6.

118. As was the case in past GCOC proceedings, parties in this proceeding presented the Commission with a wide range of recommendations for notional ROE and ERP. In addition, there is significant variability in the results obtained by applying each of the empirical models, all of which have been previously considered by the Commission.

119. In sections 6.4.1 to 6.4.4 the Commission briefly describes the empirical models, including the key variables that must be specified and associated measurement issues. In Section 6.4.5, the Commission considers the results of the models and exercises its judgment, having regard to all of the evidence in this proceeding, to determine the notional ROE and ERP. The Commission's conclusion on the notional ROE for the formula takes into account that the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities.

6.4.1 The CAPM

120. The CAPM is based on the relationship between the returns investors expect to receive on their investments in an asset and the systematic (or non-diversifiable) risk faced by that asset. The model is premised on a relationship where the required future return on the asset is proportional to that asset's risk relative to the market. This risk is measured by the asset's "beta."

121. The CAPM can be represented by the following formula:

$$Rs = Rf + \beta[Rm - Rf]$$

where:

Rs is the required return on the common stock;
Rf is the risk-free rate;
Rm is the return on the market portfolio;
Rm – Rf is the market equity risk premium (MERP); and
β, or beta, is the risk measure for the common stock.

122. Each of the variables in the CAPM equation must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The CAPM recommendations of parties are summarized in the following table.

Table 3. CAPM recommendations by party

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
D. D'Ascendis (AltaLink/EPCOR)[122]	2.88	7.64	0.61	0.50	8.38 (Canadian utility group)
	4.03	7.80	0.79	0.50	10.88 (U.S. electric utility group)
	4.03	7.80	0.76	0.50	10.70 (U.S. gas utility group)
Dr. Villadsen (ATCO/Apex/Fortis)[123]	3.85	5.91-6.56	37% Raw: 0.6-1.72 37% Blume: 0.51-1.54	-	9.81-11.76 (full comparator group)

122 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 86, 177-179. ROE results represent an average of CAPM and ECAPM models.

123 Exhibit 27084-X0469.01 PDF pages 46-49; Exhibit 27084-X0460_C, BV-12(a) ROE Model - 40%; Exhibit 27084-X0461, BV-12(b) ROE Model - 37%; Exhibit 27084-X0689.01-C, ATCO/Apex/Fortis IR responses to the AUC, PDF pages 1-4. If deemed equity is set at 40%, Dr. Villadsen calculated betas ranging from 0.56 to 1.61.

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
			37% Hamada: 1.01-1.21		
Concentric (ENMAX)[124]	3.73	7.59	0.83-0.86	0.50	10.73 (full comparator group)
Dr. Cleary (UCA)[125]	2.85	5.00	0.45	0.50	5.7 (Canadian comparator group)
D. Madsen (IPCAA)[126]	2.95	6.08	0.669	0.50	7.51 (Canadian and U.S. electric utility group)

123. The Commission did not consider the empirical CAPM (ECAPM) approach to estimate the notional ROE or ERP, consistent with the Commission's previous approach.[127] The Commission accepts Dr. Cleary's concerns with the ECAPM[128] methodology, and that the assumptions and variables used in the approach were not subject to adequate testing in this proceeding.

6.4.1.2 CAPM inputs

Risk-free rate

124. In considering the parties' CAPM ROE results, the Commission took into account the extent to which parties' estimate of the risk-free rate differed from the 3.10 per cent rate that the Commission found reasonable in Section 6.3.

Beta

125. Beta captures the sensitivity of a stock's returns to the market's returns. It is a measure of systematic risk – general risk that cannot be diversified away. In effect, beta measures the contribution made by an individual stock to the risk of the diversified market portfolio.

126. Considerable academic and empirical evidence has been filed on the record of this proceeding to support the position taken by parties on how beta should be calculated. In general, witnesses for the utilities used betas that:

- were sourced from established fee-for-service data providers widely used by the investment community, in particular Value Line and Bloomberg;
- were based on weekly data on the premise that more frequent observations better capture the contribution made by each individual stock in the comparator group of equities to the

124 Exhibit 27084-X0315, Concentric evidence, PDF pages 62, 64-65, 105. The betas used in Concentric's CAPM analyses for the entire comparator group are drawn from two sources: Value Line and Bloomberg. The MERP value of 7.59 represents an average of Canadian and U.S., historical and forward-looking values.

125 Exhibit 27084-X0320.02, Cleary evidence, PDF page 61. Beta of 0.45% is raw/unadjusted. ROE of 5.7% includes an A-rated Canadian utility bond yield spread adjustment of 0.095%.

126 Exhibit 27084-X0292, Madsen evidence, PDF pages 28-29.

127 Decision 20622-D01-2016, paragraph 199.

128 Exhibit 27084-X0759, Cleary evidence, PDF page 43-45.

risk of the diversified market portfolio over the measurement period. Selected measurement periods ranged from two[129] to five-years;[130]

- incorporated the Blume adjustment on the basis that it addresses the tendency of raw betas to change gradually over time, transforms historical unadjusted or raw betas into an expectational value consistent with the forward-looking nature of the cost of capital, and partially corrects for the known deficiencies of the CAPM;[131] and

- in the case of the evidence filed by Dr. Villadsen, used the Hamada adjustment to reflect a 40 per cent deemed equity component to standardize the capital structure of the comparable group of utilities and calculate beta[132] on an equivalent basis, given the relationship between financial leverage and equity returns.

127. For the consumer groups, Dr. Cleary and D. Madsen used a different approach to calculate beta:

- Dr. Cleary used weekly and monthly raw (unadjusted) betas for both the U.S. and Canadian comparators data from Bloomberg to arrive at an estimated beta of 0.45. Dr. Cleary did not support the use of either the Blume or Hamada adjustments to calculate beta.[133]

- D. Madsen used raw and adjusted betas in his analysis. He included Blume adjusted monthly betas on the basis that they are consistent with the forward-looking nature of a cost-of-capital determination. D. Madsen used five-year monthly data provided by YCharts and Yahoo Finance to determine an average adjusted beta of 0.669 for the combined Canadian and U.S. Electric Utility segments of the comparable group of utilities.[134] D. Madsen considered and then rejected the use of Blume adjusted, weekly Value Line betas.

128. In this proceeding, parties had much the same debates about beta as in past GCOC proceedings. Consistent with its views in past GCOC decisions, the Commission considers that there exists some room for legitimate differences of opinion among industry practitioners and academic experts on what constitutes a reasonable range for regulated utility betas.

129. For example, the Commission remains uncertain of the extent, if any, to which the Blume adjustment is warranted in determining betas for regulated utilities that face less risk than an average firm in the market. Indeed, there are ample reasons to question on what basis the

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129 Transcript, Volume 5, page 973, lines 8-11 and 15, D'Ascendis evidence. D. D'Ascendis uses Bloomberg's default setting of two years to calculate beta.

130 Exhibit 27084-X0315, Concentric evidence, PDF page 62. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Concentric has computed Bloomberg betas using five years of weekly stock returns and using the S&P or the S&P/TSX Composite as the market index, in the case of U.S. or Canadian comparable equities, respectively.

131 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 76-84; Exhibit 27084-X0315, Concentric evidence, PDF pages 62-64; Exhibit 27084-X0047, Villadsen evidence, PDF pages 7-8; and Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44.

132 Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44. Dr. Villadsen used weekly data from Bloomberg over a three-year measurement period. A similar analysis was performed assuming deemed equity of 37%.

133 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 49-60 and Exhibit 27084-X0333, Cleary evidence.

134 Exhibit 27084-X0292, Madsen evidence, PDF pages 16-22.

systematic risks faced by regulated utilities might ever be expected to approach, much less exceed, those for the market as a whole, which is a central premise of the Blume adjustment.[135] Nevertheless, the Commission acknowledges that adjusted betas are widely used by finance professionals, as they provide useful information in certain circumstances.

130. As expressed in several past decisions, the Commission remains unpersuaded that adjusted betas are superior to raw betas in the context of regulated utilities. Rather, it finds that both raw and adjusted betas can provide useful information with respect to utility risk.[136] Similarly, the Commission continues to find that reliance on both weekly and monthly estimates of beta is reasonable.[137]

131. J. Coyne estimated beta to be 0.83 to 0.86,[138] while Dr. Villadsen calculated raw, Blume and Hamada adjusted betas, producing betas ranging from 0.51 to 1.72. Within this range Dr. Villadsen recommended for the Commission's approval a range of Hamada betas from 1.01 to 1.21.[139] The Commission finds these are unreasonably high given its findings regarding the overall risk of the Alberta utilities. More generally, the Commission does not accept that betas are understated for the utilities in the absence of the Hamada adjustment.

132. The Commission concludes that utility stocks are appreciably less risky and volatile than equities in the broader market, and therefore considers a reasonable range of betas for regulated gas and electric utilities to be between 0.45 (representing Dr. Cleary's unadjusted long-term beta) and 0.75 (in the range of adjusted betas recommended by D. Madsen[140] and D. D'Ascendis[141]). The high end of Dr. Villadsen's[142] beta estimates were well above this range.

Market equity risk premium

133. Parties to the proceeding used a variety of approaches to quantify the MERP.

134. D. Madsen's MERP of 6.08 per cent is an average of three MERP estimates: the implied MERP provided by Kroll of 6.0 per cent, Dr. Damodaran's implied MERP of 6.0 per cent as of January 1, 2023, and the implied MERP calculated by D. Madsen of 6.23 per cent by applying a Gordon Growth Model to the S&P500.[143]

135. Dr. Cleary adopted a MERP of 5.0 per cent, equal to the average of a commonly used historical range of 4 to 6 per cent. Dr. Cleary relied on a series of surveys and reports from academics, investment management firms, and actuarial service providers to establish historical and forecast returns for the Canadian, U.S. and world developed markets.[144]

136. Dr. Villadsen used the historical average premium of market returns over the long-term GoC bond yields, as per Duff & Phelps, for both Canada and the U.S. The MERP is expressed as

[135] For a discussion of the history of Blume's adjustment and its limitations in the context of the regulated utility industry, see paragraph 164 of Decision 20622-D01-2016.
[136] Decision 22570-D01-2018, paragraphs 345-346.
[137] Decision 22570-D01-2018, PDF page 80, paragraph 344.
[138] Exhibit 27084-X0315, Concentric evidence, PDF page 62.
[139] Exhibit 27084-X0469.01, Villadsen evidence at PDF pages 46-48.
[140] Exhibit 27084-X0292, Madsen evidence, PDF page 29.
[141] Exhibit 27084-X0390, D'Ascendis evidence, PDF page 80.
[142] Exhibit 27084-X0469.01, PDF pages 46-49.
[143] Exhibit 27084-X0292, Madsen evidence, PDF pages 24-29.
[144] Exhibit 27094-X0320.02, Cleary evidence, PDF pages 39-49.

the arithmetic average and is 5.91 per cent for Canada (1935-2021) and 7.46 per cent for the U.S. (1926-2021). By adjusting Bloomberg forecast MERP for the spread between a 10-year and 30-year government bond yield, Dr. Villadsen also calculated a forecast MERP for Canada of 6.56 per cent and a lower number for the U.S. using proprietary data.[145]

137. D. D'Ascendis calculated a prospective MERP for both Canada and the U.S. by applying a constant growth DCF model to the companies comprising each of the S&P/TSX and S&P 500. The resulting total return for each index was then reduced by the forecast Canadian or U.S. long-term government bond yield. This produced forecast MERPs for Canada and the U.S. of 9.92 per cent and 7.03 per cent, respectively. D. D'Ascendis also estimated historical MERPs by using a regression analysis in which the MERP is expressed as a function of the long-term government bond yield. The historical MERPs for Canada and the U.S. using this approach were 5.35 per cent and 8.57 per cent, respectively.[146] The Commission notes that overall, D. D'Ascendis recommended MERPs of 7.64 for Canada and 7.80 for the U.S. as summarized in Table 3 above.

138. Concentric used the MERP ex-post historical arithmetic average based on data from Kroll of 5.74 per cent for Canada (1919-2021), and 7.46 per cent for the U.S. (1926-2021). Concentric, used an approach similar to that of D. D'Ascendis, to forecast MERPs of 9.22 per cent for Canada and 7.93 per cent for the U.S.[147] Concentric's recommended MERP, as set out in Table 3, is 7.59.

139. Parties developed their MERP recommendations using three general approaches or a combination of them. The first approach was to examine historical MERPs; that is, the difference between historical long-term realized stock market returns and the risk-free rate (as measured by long-term GoC bond yields) in Canada and the U.S. The Commission agrees that this approach is informative as it captures a large number of economic and monetary cycles and minimizes the risk that calculated MERPs reflect anomalous or transitory market conditions. The historical MERP values were approximately 6.0 per cent for Canada and 7.50 per cent for the U.S.

140. The second approach was to estimate prospective or forward-looking MERPs by relying on available market return estimates of investment management professionals and actuarial service providers, as was done by Dr. Cleary to arrive at a 4 to 6 per cent estimate and by Dr. Villadsen to arrive at a 5.91 to 6.56 per cent recommended MERP estimate.

141. The Commission recognizes that there may be pitfalls to relying on available forecasts of market return. For example, these estimates may not be as robust as empirical studies, or be amenable to ready analysis or testing, and may be prepared for different purposes; however, this type of evidence does offer some indication of what market professionals believe the ROE may be in the future. This can, and potentially does, affect investor expectations and subsequent behaviour. That, in itself, can shed light on the limits or frontiers of the range of reasonable estimates of the required ROE.

142. Under the third approach, parties estimated prospective MERPs by calculating expected market return. To do so, Concentric and D. D'Ascendis employed forecast earnings growth rates in excess of 9 per cent, which resulted in estimates for expected market returns ranging from

[145] Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 42-43. Exhibit 27084-X0458-C, Appendix BV-7 Bond Yields & MERP, tab "MRP calculation."
[146] Exhibit 27084-X0390, D'Ascendis evidence, PDF page 85.
[147] Exhibit 27084-X0315, Concentric evidence, PDF pages 64-65.

10.4 per cent to 12.8 per cent for Canada and from 11.0 per cent to 11.8 per cent for the U.S. This, in turn, produced MERP estimates in the order of 9 to 10 per cent. Consistent with the findings in the 2018 GCOC decision, the Commission considers these estimates excessive, as they are based on calculated expected market returns that reflect unrealistically high earnings growth assumptions.

143. Given the above observations, the Commission notes that when the MERP estimates in the order of 9 per cent calculated by Concentric and D. D'Ascendis are excluded, the remaining MERP recommendations of the parties fall into what the Commission considers is a reasonable range of 5.9 per cent to 7.5 per cent.

Flotation allowance

144. In past GCOC proceedings, the Commission has accepted a flotation allowance of 0.50 per cent in estimates of ROE obtained from the application of the various models, including CAPM. The flotation allowance is normally included in the approved return to account for administrative costs and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.[148] No party opposed the use of 0.50 per cent for the flotation allowance. The Commission finds this flotation allowance continues to be reasonable for use in the financial models.

6.4.2 Constant growth DCF model

145. The constant growth DCF model assumes that the market price of a stock is equal to the present value of the cash flows that the owners of the shares expect to receive. In general, expected future cash flows are represented by the dividends paid per share. This pricing relationship is generally expressed as:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty}$$

where:

$\mathbf{P_0}$ represents the current stock price;

$\mathbf{D_1 \ldots D_\infty}$ represent expected future dividends; and

k (or K) is the discount rate or required ROE.[149]

146. Each of the variables in the DCF approach must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The constant growth DCF recommendations by parties are summarized in Table 4.

[148] Decision 22570-D01-2018, PDF page 104.
[149] The expression can be simplified and rearranged into annual and quarterly compounding DCF equations: Exhibit 27084-X0292, Madsen evidence, PDF page 29.

Table 4. Constant growth DCF recommendation by party

Witness (sponsoring party)	ROE	Flotation allowance[150]	ROE including flotation allowance
	(%)		
D. D'Ascendis (AltaLink/EPCOR)[151]	10.21 (Canadian utilities) 9.34 (U.S. electric utilities) 10.01 (U.S. natural gas utilities)	0.50	10.71 (Canadian utilities) 9.84 (U.S. electric utilities) 10.51 (U.S. natural gas utilities)
Dr. Villadsen (ATCO/Apex/Fortis)[152]	12.79 (Canadian utilities) 9.38 (U.S. electric utilities) 9.66% (U.S. gas utilities)	0.50	13.29 (Canadian utilities) 9.88 (U.S. electric utilities) 10.16 (U.S. gas utilities)
Concentric (ENMAX)[153]	9.88 (Canadian proxy group) 9.43 (U.S. electric proxy group) 9.84 (U.S. gas proxy group) 9.59 (N.A. combined proxy group)	0.50	10.38 (Canadian proxy group) 9.93 (U.S. electric proxy group) 10.34 (U.S. gas proxy group) 10.09 (N.A. combined proxy group)
Dr. Cleary (UCA)[154]	6.35	0.50	6.85
D. Madsen (IPCAA)[155]	7.31-9.14	0.50	7.81-9.64

6.4.2.1 Constant growth DCF inputs

Current stock price

147. To estimate the current stock price input to the DCF model, most parties calculated the average closing price over a period ranging from 15 to 90 trading days ending between late December 2022 and late January 2023 to avoid biases that may arise over very short periods of time from anomalous or transitory events.[156]

148. The Commission accepts the use of an averaging period to calculate the current stock price to mitigate the risk that a single date, point-in-time estimate may be biased by market conditions on the pricing date. The averaging period should not exceed 90 days, as a longer averaging period would likely violate the empirical assumption that the constant growth DCF approach uses current stock prices. In addition, the Commission will accept the adjustment of the current quarterly dividend by the chosen dividend growth rate, as submitted by D. D'Ascendis, Dr. Villadsen and Concentric. No party provided a contrary view that the adjustment was inappropriate.[157]

150 The constant growth DCF directly calculates ROE prior to the addition of the flotation allowance.
151 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 47. Average of the mean and median.
152 Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 54-55. Exhibit 27084-X0460-C, BV-12a, Villadsen evidence. ROE values are presented at 40% equity thickness.
153 Exhibit 27084-X0315, Concentric evidence, PDF pages 53-57. Exhibit 27084-X0490, Concentric evidence, sheet JMC-3 Constant DCF. ROE results represent mean values. Of note, Concentric's recommended ROE of 9.50% is based on the average of the multi-stage DCF model (not the constant growth DCF model).
154 Exhibit 27084-X0320.02, Cleary evidence, PDF page 71. Dr. Cleary used only the Canadian utilities in his recommendations.
155 Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Attachment 1, Madsen evidence, Tab "DCF." D. Madsen does not use the U.S. Gas utility comparable equities in his constant growth analysis and excludes Algonquin Power & Utilities Corp. from his DCF calculations.
156 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 42; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1, Exhibit 27084-X0292, Madsen evidence, PDF page 32.
157 The Commission notes that the constant growth DCF formula set out at the beginning of the section is taken from D. Madsen's evidence and clearly shows the adjustment of the dividend by the growth rate (footnote 55).

Dividend

149. The experts adopted slightly different approaches to how they calculated dividends. Most took the annualized dividend at year-end 2022 for each utility and then increased it quarterly or semi-annually by a fixed percentage of the forecast growth rate.[158] Dr. Cleary's approach was to provide a number of dividend yield calculations, including trailing 12-month dividend yields from December 2022 and average five-year and seven-year dividend yield averages.[159]

Dividend growth rate

150. Several of the experts relied on analysts' forecasts of company-specific dividend and earnings per share (EPS) growth rates.[160] D. Madsen also considered data from other sources and both he and Dr. Cleary[161] considered historical data. There was debate on whether dividend growth rates in the constant growth DCF analysis can the exceed the growth rate of the overall economy, as measured by the GDP growth rate. For example, D. Madsen said that, generally, dividend growth estimates should be below forecast growth in nominal GDP, while D. D'Ascendis did not agree with such limitation.

151. In past GCOC decisions the Commission rejected the use of dividend growth rates that exceeded estimates of the nominal long-term GDP growth rate. In this proceeding, Concentric filed evidence that earnings and dividend growth have exceeded GDP between 2007 and 2021 in support of the proposition that analyst estimates of growth rates above GDP are reasonable.[162] D. D'Ascendis indicated that the compound annual utility industry EPS growth rate of 6.53 per cent exceeded the U.S. GDP growth rate over the 1947 to 2021 period.[163] While this supports the view that utility EPS growth can exceed nominal GDP growth, the Commission notes that D. Madsen provided evidence of the recent historical EPS growth rates of the Alberta utilities and concluded that average growth was generally lower than his forecast nominal GDP.[164] Further, he noted that the Alberta utilities have a "natural barrier to growth" due to their inability to expand into other jurisdictions.[165] On this point, the Commission notes that growth in dividends can come from higher earnings, and not only from the expansion of company operations.

152. Nevertheless, as in past decisions, the Commission remains concerned with the aggressive dividend growth rates and forecasts relied on by some experts for the utilities, both for utilities as a sector of the economy, and the economy as a whole. It notes Dr. Cleary's observation regarding high growth estimates put forward by experts for the utilities and for the economy as a whole:

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158 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 41; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0292, Madsen evidence, PDF page 32; Exhibit 27084-X0304, Madsen evidence, Sheet DCF.

159 Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1.

160 Exhibit 27084-X0391, D'Ascendis evidence, Sheets 2.2-2.4 CGDCF. EPS estimates were from Value Line, Zack's, and Yahoo! Finance; Exhibit 27084-X0469.01, Villadsen evidence, PDF page 51; Exhibit 27084-X0315, Concentric evidence, PDF page 54.

161 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 64-65.

162 Exhibit 27084-X0315, Appendix 1, Evidence of Concentric Energy Advisors, PDF pages 56-57.

163 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 159, Schedule 3, and Exhibit 27084-X0665.

164 Exhibit 27084-X0292, Madsen evidence, PDF page 38.

165 Exhibit 27084-X0292, Madsen evidence, PDF page 38.

> The contradiction in these assumptions is obvious – i.e. if the economic environments are expected to experience high-risk and slow growth conditions, how is it reasonable to assume that corporate earnings and dividends (for the entire stock market of all publicly listed companies) can be expected to grow indefinitely at these abnormally high rates?[166]

153. In the 2018 GCOC decision, with reference to Dr. Cleary's evidence, the Commission recognized that the utilities are essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable.[167] Indeed, D. Madsen quoted in his evidence from a publication by Dr. Damodaran, who opined that it is questionable whether any firm is able to sustain high growth in the long term as it will eventually stop growing either due to limitations on size or to the effects of competition.[168]

154. On the other hand, the sustainable growth rate Dr. Cleary used to estimate expected dividend growth rates relied on historical seven-year average dividend yields and payout ratios and used accounting data, rather than readily available, market-driven forecasts. The Commission notes that this approach produces growth estimates that are less than actual historical rates of dividend growth[169] and less than inflation, resulting in negative real growth. As a result, the Commission is concerned that Dr. Cleary's sustainable growth rate produces results that understate dividend growth.

155. The Commission will generally continue to consider forecast long-term nominal GDP growth as a proxy for forecast dividend growth. Growth of the utilities will fluctuate over the years but, overall, considering the business profile of the utilities, the Commission does not expect the utilities will consistently achieve growth in dividends greater than the nominal GDP growth rate.

156. In this regard, the Commission finds it reasonable to use in the constant growth DCF model the minimum and mean analyst growth rates submitted in this proceeding; however, maximum EPS growth rates appear to be unreasonably high. Despite its general criticism of using high dividend growth rates, the Commission notes that analyst EPS growth estimates are widely used by the investment community, and concerns relating to analyst EPS optimism bias for large capitalization stocks like those in the comparator group may be overstated, at least relative to estimates for small to mid-cap stocks of which there are not many in the comparator group, in any event.[170] The use of analyst EPS estimates supplied by established data service providers, such as Value Line, Zack's, Yahoo! Finance, SNL Financial, and Thomson First Call minimizes the opportunity for arbitrary adjustments and custom calculations for which there is no broad support among parties to the proceeding.

6.4.3 Multi-stage DCF model

157. The multi-stage DCF model reflects the premise that investors value an investment according to the present value of its expected cash flows over time.[171] It is an extension of the constant growth DCF model, but the multi-stage DCF approach does not assume a single,

166 Exhibit 27084-X0759, Dr. Cleary rebuttal evidence (redacted), PDF page 3.
167 Decision 22570-D01-2018, paragraph 438.
168 Exhibit 27084-X0292, D. Madsen evidence, PDF pages 34-35.
169 Exhibit 27084-X0304, Madsen evidence, Tab DCF, column "Growth forecast past 5 years (per annum)."
170 Transcript, Volume 3, pages 704-722.
171 Exhibit 27084-X0390, Concentric evidence, PDF page 53.

constant estimate of dividend growth in perpetuity.[172] In general, the multi-stage DCF assumes that dividends grow at a constant rate over a short-term period, usually five years in length, transition to an assumed long-term constant growth rate over an interim period, also usually five years in length, and then grow in perpetuity at a growth rate usually equal to forecast nominal GDP.

158. The multi-stage DCF recommendations of parties are summarized in the following table.

Table 5. Multi-stage DCF recommendations of parties

Witness (sponsoring party)	ROE	Flotation allowance	ROE including flotation allowance
		(%)	
D. D'Ascendis (AltaLink/EPCOR)[173]	10.34 (Canadian utilities) 9.21 (U.S. electric utilities) 9.39 (U.S. natural gas)	0.50	10.84 (Canadian utilities) 9.71 (U.S. electric utilities) 9.89 (U.S. natural gas)
Dr. Villadsen ATCO/Apex/Fortis)[174]	11.81 (Canadian utilities) 7.88 (U.S. electric utilities) 7.62 (U.S. gas utilities)	0.50	12.31 (Canadian utilities) 8.38 (U.S. electric utilities) 8.12 (U.S. gas utilities)
Concentric (ENMAX)[175]	9.42 (Canadian proxy group) 8.28 (U.S. electric proxy group) 8.65 (U.S. Gas proxy group) 8.49 (N.A. combined proxy group)	0.50	9.92 (Canadian proxy group) 8.78 (U.S. electric proxy group) 9.15 (U.S. gas proxy group) 8.99 (N.A. combined proxy group)
Dr. Cleary (UCA)[176]	7.01	0.50	7.51
D. Madsen (IPCAA)[177]	7.38-8.46	0.50	7.88-8.96

6.4.3.1 Multi-stage DCF inputs

159. The variables that must be estimated in a multi-stage DCF equation are the same as those set out in Section 6.4.2, except the assumed short-term and long-term dividend growth rates and the length of the short-term and transition periods are expressed in years.

Dividend growth rate

160. Most of the experts calculated the multi-stage DCF in a similar manner, and many of the variables are calculated in the same way as for the constant growth DCF calculations, other than the dividend growth rate. As was the case for the constant growth DCF model, parties took different approaches to forecasting the growth rate.[178] In forecasting nominal GDP growth rates, parties used either the Canadian forecast, or a combination of the Canadian and U.S. forecast.

172 Exhibit 27084-X0390, Concentric evidence, PDF page 53.
173 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 50. Recommended M-DCF reflects average of mean and median results.
174 Exhibit 27084-X0469.02, Villadsen evidence, PDF pages 54-55. ROE values are presented at 40% equity thickness.
175 Exhibit 27084-X0315, Concentric evidence, PDF page 59. Exhibit 27084-X0490, tab "JMC-4 Multi-Stage DCF."
176 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 70-71.
177 Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Madsen evidence, Sheet DCF.
178 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 47-48. Exhibit 27084-X0391, D'Ascendis evidence, sheets 2.5-2.8, Exhibit 27084-X0469, Villadsen evidence, PDF pages 49-57. Exhibit 27084-X0471, Villadsen evidence, PDF pages 10-13, Exhibit 27084-X0315, Concentric evidence, PDF pages 57-58. Exhibit 27084-X0490, Sheet JMC-4 Multi-Stage DCF.

161. D. Madsen also calculated the multi-stage DCF using the approach used by the U.S. Federal Energy Regulatory Commission (FERC), applying it to several scenarios.[179] Using the FERC approach led to similar growth rates. Dr. Cleary took a slightly different approach and used a variation of the constant growth DCF called the H-Model. The approach assumes that growth in dividends moves in a linear manner from a short-term growth rate toward a long-term growth rate over a specified period of time, defined as the "half life."

162. D. Madsen's multi-stage DCF calculations included using current and one-year forecast EPS growth rates as a proxy for a five-year forecast EPS growth rate or a one-year EPS growth estimate in year one and the five-year EPS estimate in years two to five.[180] D. Madsen also used the FERC two-step DCF approach. He made adjustments to the FERC approach, including the weights used for short- and long-term growth, and used a simple average of the short-term and long-term growth estimates to adjust the dividend. These adjustments were criticized by Dr. Villadsen and D. D'Ascendis.[181]

163. The multi-stage DCF approach used by Dr. Villadsen[182] models the first five years of dividends at a growth rate specific to the company she is estimating, then tapered the growth down towards that of the economy over the next five years. For year 10 onwards, Dr. Villadsen used the GDP growth rate as the perpetual growth rate for dividends.

164. Regarding the results of Dr. Cleary's H-Model DCF approach, the Commission is persuaded by the concerns expressed by experts for the utilities who raised a number of empirical and qualitative issues with Dr. Cleary's approach. These included the use of sustainable growth rates that are less than forecast inflation,[183] resulting in negative real utility growth, sustainable growth rates that are less than historical actuals,[184] and the need to consider growth arising from both internally generated funds and from issuances of equity.[185]

6.4.4 Other risk premium models

165. In addition to relying on CAPM and DCF models, some parties used the following risk premium models to help inform their fair ROE estimates: (i) Concentric and Dr. Villadsen used the government bond yield risk premium model; (ii) Dr. Cleary and D. D'Ascendis relied on the utility bond risk yield premium model; and (iii) D. D'Ascendis used the predictive risk premium model. The Commission determines that it will not rely on any of these models for the purposes of the present decision.

179 Exhibit 27084-X0292, Madsen evidence, PDF pages 42-44. Exhibit 27084-X0304, Madsen evidence.

180 Exhibit 27084-X0304, Madsen evidence, Sheets DCF and Multi DCF Alt. FERC Scenario 1: nominal estimated GDP of 3.77% is used for both the short-term and long-term growth rate; FERC Scenario 2: short-term growth rate is the average of the current year forecast and next year's growth rate and nominal estimated GDP of 3.77% is used as the long-term growth rate; FERC Scenario 3: short-term growth rate is equal to analyst five-year EPS growth rates and nominal estimated GDP of 3.77% is used as the long-term growth rate; and FERC Scenario 4: the average the short-term growth rate in scenarios 1 to 3 is used as the short-term growth rate and the long-term growth rate is nominal estimated GDP of 3.77%.

181 Exhibit 27084-X0761, Villadsen evidence, PDF pages 26-27, Exhibit 27084-X0750, D'Ascendis evidence, PDF pages 32-36.

182 Exhibit 27084-X0471, Villadsen evidence, PDF pages 9-10.

183 Exhibit 27084-X0750, D'Ascendis evidence, PDF page 29.

184 Exhibit 27084-X0743, Concentric evidence, PDF page 41.

185 Exhibit 27084-X0761.02, Villadsen evidence, PDF page 61.

166. The government bond risk premium approach estimates the ROE as the sum of the ERP and the yield on the 30-year U.S. Treasury bond. The ERP was calculated as the difference between authorized returns from U.S. electric and gas utilities and the then-prevailing quarterly 30-year U.S. Treasury yield. Consistent with prior GCOC decisions,[186] the Commission continues to be of the view that the approved ROEs from other jurisdictions are not, strictly speaking, wholly market-based data and therefore, will not place any weight on the results of the government bond risk premium model.

167. Under the utility bond risk premium approach, a required ROE is calculated by adding an equity premium to a utility bond yield. In past GCOC decisions, the Commission accepted the bond yield and utility bond yield approaches to be valid tools in estimating the cost of equity, as they are simple to use and conform to the basic principle that investors require a higher return for assets with greater risk. Although the Commission still considers the empirical basis of the utility bond yield methodology to be valid, for the purposes of this decision the Commission will not rely on the utility bond yield risk premium approaches used by Dr. Cleary and D. D'Ascendis.

168. Dr. Cleary's recommended risk premium of 2.50 per cent is subjective, not supported by any analysis and does not take into the account the changing market environment. D. D'Ascendis's risk premiums are estimated in a more rigorous manner; however, they have issues of their own. For one of his models, D. D'Ascendis used the authorized ROEs from litigated cases in other jurisdictions to estimate the utility bond ERP.[187] As stated earlier, the Commission prefers not to use authorized ROEs as a proxy for market data. For the other two models, D. D'Ascendis relied on market data; however, they require the Commission's determinations on a number of new variables such as the expected utility bond yields and expected returns for an index of U.S. utilities.[188] Variables and calculations in D. D'Ascendis's bond yield risk premium models were not explored in depth in this proceeding, and in the Commission's view, the merits of the utility bond risk premium approach do not outweigh the additional burden and empirical difficulties associated with measuring the ERP to utility bond yield, given the presence of the more widely accepted CAPM and DCF models.

169. Finally, the predictive risk premium model is based on the ARCH/GARCH[189] models that use historical volatility to predict future volatility, which can then be translated to a predicted ERP. The predictive risk premium model estimates the ERP directly, by predicting volatility or risk.[190] In the Commission's view, this analysis is similar in concept to the technical analysis of market data that relies only on historical time series data for a single indicator, for example, returns on a stock, to predict future returns for this stock. The Commission is not persuaded that this approach is superior to the CAPM and DCF models that use a variety of inputs to estimate the ERP and/or required return, especially as the predictive risk premium model approach is not used widely, if at all, by other regulators.

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186 Decision 22570-D01-2018, PDF pages 88-91.
187 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 64.
188 In Exhibit 27084-X0390, PDF page 63, D'Ascendis explained, "As done for the S&P TSX Composite and the S&P 500, using dividend and EPS growth rate data from Bloomberg, I calculated projected total returns of the S&P/TSX Capped Utilities."
189 The Autoregressive Conditional Heteroskedasticity (ARCH) and Generalized Autoregressive Conditional Heteroskedasticity (GARCH) models are based on the premise that the volatility of prices and returns clusters over time and is therefore highly predictable.
190 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 54-60.

6.4.5 Notional ROE and base forecast ERP

170. In this proceeding, the Commission was presented with a wide range of notional ROE and base ERP recommendations that were based on a variety of approaches, models and directional indices. The Commission rejected many of these approaches and instead focused on the results of the well-known and widely used models (CAPM, constant growth DCF, and multi-stage DCF) in GCOC proceedings. The Commission determines the notional ROE to be 9.00 per cent and the base forecast ERP to be 5.90 per cent.

171. Table 6 illustrates the ranges of notional ROE (including 0.50 flotation allowance) based on the results of the financial models submitted by the parties and reflects the resulting ERPs after subtracting the Commission's 3.10 per cent risk-free rate.

Table 6. Notional ROE and base forecast ERP from financial models

Financial model	ROE (%) range		Base forecast ERPs (%) range including flotation allowance (ROE less 3.10% risk-free rate)	
	Low	High	Low	High
CAPM	5.7	11.76	2.6	8.66
Constant growth DCF	6.85	13.29	3.75	10.19
Multi-stage DCF	7.51	12.31	4.41	9.21

172. It is obvious from the table above that the Commission was presented with a wide range of results from the experts using the CAPM, constant growth DCF, and multi-stage DCF models. The model results are subject to a high degree of variability given the range of data sources, forecasts and assumptions that parties choose to use, and the judgment and experience of the expert doing the modelling. These models provide some guidance to the Commission, but, as evidenced by the wide range of results, they do not produce a single correct number for the fair return that the Commission should choose.

173. In assessing the results of the models, the Commission is mindful of its concerns expressed in sections 6.4.1 to 6.4.3, including:

- CAPM results using a forecast risk-free rate that differs significantly from the 3.10 per cent rate the Commission found reasonable in Section 6.3.
- CAPM results using betas that were close to or exceeded one.
- CAPM results using MERPs based on excessively high earnings growth rates in estimating market return.
- Constant growth DCF results using dividend growth rates that are too high (e.g., exceed long-term nominal GDP growth) or too low (e.g., near or less than inflation).

174. The Commission has set the base forecast ERP and resulting notional ROE towards the lower end of the ROE ranges calculated in the financial models given its finding that the risk profile of the Alberta utilities is at the low end of the comparator group of companies.

175. D. D'Ascendis calculated a low CAPM ROE of 8.38 per cent, a constant growth DCF ROE of 9.84 to 10.71 per cent and a multi-stage DCF ROE of 9.71 to 10.84 per cent. Some of D. D'Ascendis's DCF ROE estimates are based on excessively high earnings growth rates, which

the Commission rejects. The notional ROE of 9.00 per cent is closer to the lower end of D. D'Ascendis's three calculations, namely the low 8.38 per cent CAPM ROE.

176. The low end of Dr. Villadsen's calculated ROEs was the 8.12 per cent for the multi-stage DCF. Dr. Villadsen's CAPM ROE of 9.81 to 11.76 per cent uses a high beta and high risk-free rate. Concentric's CAPM ROE of 10.73 uses a lower beta and risk-free rate than Dr. Villadsen; however, Concentric's risk-free rate is 3.73 per cent. The low end of Concentric's calculated ROEs is 8.78 per cent for the multi-stage DCF. Dr. Villadsen and Concentric's constant growth DCF ROEs range from 9.88 to 13.29 per cent, and 9.93 to 10.38 per cent, respectively. Some of Concentric's constant growth DCF estimates are based on excessively high earnings growth rates, which the Commission rejects.

177. The high end of Dr. Cleary's three ROE calculations was 7.51 per cent for the multi-stage DCF but even that high-end estimate is too low. It is approximately 100 basis points lower than the current approved ROE, and the Commission finds no compelling reason to decrease the currently approved ROE. D. Madsen calculated a CAPM ROE of 7.51 per cent, a constant growth DCF ROE range of 7.81 per cent to 9.64 per cent, and a multi-stage DCF ROE range of 7.88 per cent to 8.96 per cent. Given the Commission's finding that there is no compelling reason to decrease the currently approved ROE, the Commission considers the higher end of D. Madsen's constant growth DCF and multi-stage DCF ROEs to be more helpful. D. Madsen uses long-term nominal GDP growth rates in his DCF models. The notional ROE of 9.00 per cent is lower than D. Madsen's 9.64 per cent constant growth DCF ROE, and slightly higher than D. Madsen's 8.96 per cent multi-stage DCF ROE.

178. In addition to the various factors outlined above, the Commission's reasoning in setting the base forecast ROE and notional ROE on the lower end of the ROE ranges developed by parties in this proceeding includes the considerations set out below.

179. A great deal of evidence (and supporting argument) was filed in this proceeding by the utilities in an effort to persuade the Commission that the macroeconomic changes (and related systematic risks) confronting them compared to what they faced in 2018, together with other business, market, regulatory, competitive and related operating risks they deal with on a daily basis, warrant a significant increase in both their approved ROEs and deemed equity ratios commencing in 2024. After considering the full record of this proceeding, the Commission finds that, on balance, there are reasonable grounds for the notional ROE for Alberta utilities to be raised above the 8.5 per cent ROE approved for 2023, but not to set it as high as the utilities have been requesting.

180. Utilities are regulated monopolies. They supply essential, highly price-inelastic, services to captive customers, with few, if any, competitively available substitutes. Aside from fluctuations attributable to short-term extremes of weather, natural disasters, pandemics and the like, demand for their services is highly predictable from one season to the next, and one year to another.

181. In exchange for being cloaked with a legislative "duty to serve" or "supplier-of-last-resort" obligation as it is sometimes called, public utilities have long been the beneficiaries of a statutory guarantee, enforced by regulation and a century or more of appellate level jurisprudence, of a legal right to a reasonable opportunity to earn a fair return on their prudently invested capital. As leading credit rating agencies have noted on more than one occasion, utilities

under the Commission's jurisdiction face a favourable regulatory environment that excludes some or all of volumetric, counterparty and commodity price risks,[191] and allows for the flowthrough to customers of most, if not all, cost increases that are outside the utility's direct control.

182. Alberta utilities are also the beneficiaries of a concerted effort in recent years to eliminate regulatory lag and to reduce unnecessary regulatory burden, plus numerous incentives to cut costs and earn supra-normal returns (i.e., earnings in excess of their approved rate of return) between rate cases under cost-of-service (COS) regulation for transmission utilities or performance-based regulation (PBR) terms for distribution utilities.[192] Together, these conditions have the effect of significantly reducing the overall level of risk faced by Alberta utilities relative to the market as a whole. As noted in Section 4 above, while many competitive industries endured considerable economic and financial duress attributable to pandemic-related disruptions in the past few years, Alberta utilities appear not only to have avoided any lasting economic harm but have also exhibited, overall, very robust financial results throughout. Moreover, the fact that no evidence was presented by utilities attesting to undue hardship in raising new debt or equity capital on competitive terms at any time since the 2018 GCOC proceeding reinforces the overall conclusion that they operate in a lower risk and relatively more supportive regulatory environment than that of the comparator group.

6.5 Other variables of the formulaic approach

183. The approved notional ROE of 9.0 per cent will serve as a base ROE to which the approved formulaic approach will be applied each year:

$$ROE_t = 9.0\% + 0.5 \times (\text{YLD}_t - 3.10\%) + 0.5 \times (\text{SPRD}_t - \text{SPRD}_{base})$$

184. This section explains how the Commission arrived at each remaining variable to be used in the approved formulaic approach. Specifically, Section 6.5.1 deals with the adjustment factors for changes in GoC bond yield and utility bond yield spread. Section 6.5.2 deals with the base and test year values for long GoC bond yields. Section 6.5.3 deals with the base and test year values for utility bond yield spreads.

6.5.1 Adjustment factors for changes in GoC bond yield and utility bond yield spread

185. In future test years, risk-free rates (approximated by long-term GoC bond yield) and utility bond yield spreads will continue to vary as financial and economic conditions evolve. The approved formulaic approach accounts for fluctuations in both of these factors relative to their base values approved in this decision.

186. The adjustment factor for the 30-year GoC bond yield (denoted as w_1 in the formula) expresses the relationship between changes in the forecast long GoC bond yield and the ROE for the test year. The adjustment factor for utility bond yield spread (denoted as w_2 in the formula) expresses the relationship between changes in the utility bond yield spread and the ROE for the test year. The theoretical basis behind these adjustment factors is that the ROE (and underlying

191 Exhibit 27084-X0897, IPCAA-ATC-4, Extract from Proceeding 28174, Exhibit 28174-X0011, SP Rating Results for AltaLink, L.P., PDF pages 4 and 6.

192 The Commission recognizes that utilities subject to COS regulation do not have the same incentives and returns as utilities subject to PBR. Notwithstanding that, the Commission observes that some Alberta utilities under COS regulation do achieve returns over approved ROE.

ERP) do not change one-for-one with the change in risk-free rate and bond yield spread; rather, they change to some lesser degree in response to fluctuations in those variables.

187. Ideally, the values for these adjustment factors should be determined through an empirical exercise based on the strength of the relationship between interest rates and ERPs observed by analysing historical data. To that effect, the Commission asked parties to comment on the extent of the relationship between changes in the forecast long GoC bond yield and the forecast ERP, and whether this relationship is sustainable and statistically significant with a high coefficient of determination.

188. In the Commission's view, the results of the statistical analyses presented in this proceeding were not conclusive. Although there were some statistical analyses showing that the 0.5 adjustment factors for both w_1 and w_2 were in the range of reasonableness,[193] with the exception of Concentric, parties did not rely heavily on their statistical analyses and, instead, appeared to defer to the OEB adjustment factors of 0.5 for both w_1 and w_2, the latter of which is also used by the California Public Utilities Commission (CPUC). This was the approach taken by Dr. Villadsen,[194] D. D'Ascendis[195] and D. Madsen.[196]

189. Concentric's regressions showed a statistically significant, sustained relationship between changes in risk-free rates and authorized ROEs as well as between changes in utility bond yield spreads and authorized ROEs.[197] Based on these regressions, Concentric recommended the 0.5 adjustment for both factors in the formula.[198] However, the Commission will not rely on this analysis given its determination, expressed throughout this decision, not to use authorized ROEs as a proxy for market data.

190. An alternative to the adjustment factors used by the OEB was presented by Dr. Cleary who recommended adjustment factors of 0.75 for both w_1 and w_2. The Commission is not persuaded that a 0.75 adjustment factor is warranted. Although of limited usefulness, the statistical analyses on the record of this proceeding (not including Concentric's) do provide general support for the 0.5 adjustment factors; at least more so than for the 0.75 adjustment factor. In addition, both the OEB and the EUB found that the 0.75 adjustment factor with respect to changes in GoC bond yield resulted in unduly heightened sensitivity to GoC bond yield, contributing to the demise of their formulas that were in place pre-2009.[199] The Commission agrees with the approach taken by the majority of parties that it is preferable to use the adjustment factors used by the OEB and CPUC whose formulas have been in place for a number of years.

[193] Exhibit 27084-X0900, Madsen undertaking No. 1. D'Ascendis: Exhibit 27084-X0399, Morin approach; Exhibit 27084-X0408, Harris approach; Exhibit 27084-X0411, Harris and Marston approach; Exhibit 27084-X0413, Brigham, Shome and Vinson approach; Exhibit 27084-X0440, Maddox, Pippert and Sullivan approach. Dr. Cleary: Exhibit 27084-X0605, UCA-AUC-2023FEB21-005, PDF pages 14-15.
[194] Exhibit 27084-X0469, Villadsen evidence, PDF page 79.
[195] Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 105, 112.
[196] Exhibit 27084-X0292, Madsen evidence, PDF page 50.
[197] Exhibit 27084-X0490, tabs "JMC-7.1 Risk Premium – Electric" and "JMC-7.2 Risk Premium – Gas."
[198] Exhibit 27084-X0315, Concentric evidence, PDF page 109. Exhibit 27084-X0743, Concentric reply evidence, PDF page 51.
[199] Exhibit 27084_X0678, EDTI-AML-CCA-2023FEB21-003 Attachment (OEB Report), PDF page 3.

191. The Commission approves a 0.5 adjustment factor for both changes in the 30-year GoC bond yield (w_1) and changes in the utility bond yield spread (w_2) in the formula.

6.5.2 Base and test year values for long-term GoC bond yield

192. As set out in Section 6.3, the risk-free rate of 3.10 per cent will serve as the base long-term GoC bond yield (YLD_{base}) in the formulaic approach. The updated risk-free rate forecast for each test year will be measured against this base value.

193. Regarding the 30-year GoC bond yield forecast for the prospective test year (YLD_t), parties recommended that methodologies be employed consistent with the methods they used to arrive at their respective base risk-free rate estimates (these methodologies are summarized in Table 1 from Section 6.3). Parties' choice of which forecast publication date to use was based on their assumptions as to when the Commission will calculate the ROE for the upcoming test year; on that basis parties presumed the Commission will rely on either September or October data.

194. The Commission agrees with parties that it is beneficial to maintain consistency in forecasting methods between base and test year values and therefore will use the same method for forecasting the risk-free rate. In Section 6.3, the Commission determined that it will base the calculations for a test year on the data from October of the preceding year. Consistent with these determinations, the Commission finds that forecast long-term GoC bond yield will be calculated as the weighted average of (i) the 30-year GoC bond yield forecasts published by RBC, TD and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (ii) the naïve forecast representing the average long-term GoC bond yield[200] over the period October 1 to October 31 each year preceding the test year (0.25 weight).

6.5.3 Base and test year values for utility bond yield spread

195. In general terms, the utility bond yield spread is calculated as a difference between the utility bond yield and GoC bond yield of the same maturity.

196. Consistent with her recommendations to use the 30-year GoC bond yield for the forecast risk-free rate, Dr. Villadsen recommended calculating the spread against the yield on 30-year utility bonds. Dr. Villadsen also advised that the utility bond yield spread should be estimated using a bond index that measures the market-based yields on a broad portfolio of Canadian utility bonds. She recommended the 30-year A-rated Canadian Utility Bond Index from Bloomberg (Series C29530Y) for this purpose. The spread can then be calculated as the current yield on 30-year A-rated Canadian utility bonds minus the current yield on the 30-year GoC bond, as of the same valuation date that the other "base" inputs are established in the formula. Dr. Villadsen stated the Commission may consider using the average yield over a historical period (e.g., the prior 15 days) to account for any potential one-day pricing effects.[201] In her evidence, Dr. Villadsen noted that the base spread at the end of November 2022 was 1.63 per cent.[202]

197. Other parties generally followed the same methodology as Dr. Villadsen for calculating the base utility bond yield spread, but differed in certain aspects. In Concentric's view, the utility

[200] Bank of Canada CANSIM Series V39056.
[201] Exhibit 27084-X0469.01, PDF page 82.
[202] Exhibit 27084-X0469.01, PDF page 33 at Figure 6, PDF page 80.

bond yield spread should consider both A-rated and Baa-rated utility bonds because not all of the Alberta utilities have an A rating. Further, Concentric suggested that if the A and Baa-rated bond yield spreads differ, the Commission could average them or differentiate the resulting ROE separately for the A and sub-A rated utilities. Concentric stated that the base utility bond spread should be calculated based on market data at the end of December 2022.[203] D. D'Ascendis recommended setting the base spread using the average utility bond yield spread for the month of December 2022 in the amount of 1.64 per cent.[204] Dr. Cleary recommended using the actual, prevailing A-rated 30-year utility bond yield spread at the time the base ROE is set. For example, Dr. Cleary observed that the 30-year GoC bond yield of 2.85 per cent as of January 19, 2023, implied an A-rated utility yield spread of 1.58 per cent versus the spread of 1.31 per cent as of January 2020, and the average spread of 1.39 per cent over the January 3, 2003, to January 19, 2023 period.[205]

198. Regarding the utility bond yield spread for the upcoming test year, parties preferred to use the same methodologies they recommended for calculating the base value of the spread. The only difference was to use data from either September or October, i.e., at the same time the Commission computes the other parameters of the formulaic approach.

199. The Commission agrees with the mechanics of the utility bond yield spread calculations as described by Dr. Villadsen and used by most parties. The Commission also agrees with the selection of the 30-year A-rated Canadian Utility Bond Index from Bloomberg given the Commission's continued recognition of the importance of maintaining a target credit rating for the Alberta utilities in the A-range, as discussed in Section 7.3. As well, the Commission agrees with Dr. Villadsen that the base utility bond yield spread should be set based on data from the same time period that is used to establish the other "base" inputs in the formula. Therefore, the Commission will use the average utility bond yield spread for the month of February 2023 for the base value in the formula to be consistent with the time period selected for the data used to set the risk-free rate in Section 6.3.

200. The record of this proceeding includes some monthly data for the base utility bond yield spread but the average daily spread for February 2023 is not available on the record and its calculation requires proprietary data (Bloomberg Series C29530Y). Therefore, the Commission directs the ATCO Utilities, who sponsored the evidence of Dr. Villadsen, to calculate the average utility bond yield spread for the period from February 1 to February 28, 2023 using the calculation steps described in her evidence. The ATCO Utilities are further directed to provide these calculations and the resulting utility bond yield spread value as a post-disposition filing to this proceeding by October 18, 2023. Once confirmed by the Commission, this value will be used as the base utility bond yield spread ($SPRD_{base}$) in the approved formula.

201. Regarding the utility bond yield spread for the test year ($SPRD_t$), as was recommended by the majority of parties, the Commission will calculate the average difference between (i) the 30-year A-rated Canadian utility bond yield[206] and (ii) the long-term GoC bond yield[207] over the period October 1 to October 31 of the year preceding the test year.

203 Exhibit 27084-X0315, PDF page 111.
204 Exhibit 27084-X0390, PDF page 9.
205 Exhibit 27094-X0320.02, PDF page 20.
206 Bloomberg Series C29530Y.
207 Bank of Canada CANSIM Series V39056.

TAB 8

Independent expert report for the Generic Proceeding on cost of capital and other matters (EB-2024-0063)

prepared for the Ontario Energy Board ("OEB" or "the Board") by London Economics International LLC ("LEI")

June 21st, 2024

LEI was engaged by OEB Staff to assist their participation in the generic proceeding on cost of capital and other matters (referred to as "Generic Proceeding" or "EB-2024-0063"), and file evidence, testify and provide an independent analysis of the relevant matters pertaining to utilities and the Ontario energy sector.

In this report, LEI was asked to review the 22 issues (primarily related to matters associated with cost of capital) identified in the OEB's Final Issues List for the Generic Proceeding. LEI has evaluated precedents, practices followed in North American and global jurisdictions, current landscape, and potential alternatives, and made recommendations based on the following principles: (i) meeting the Fair Return Standard ("FRS"); (ii) simple to administer relative to the status quo; (iii) transition from status quo only if the benefits of transition are material; (iv) fairness in approach to consumers and utilities; and (v) predictability and transparency.

Overall, LEI proposes evolutionary rather than revolutionary changes in response to the issues identified in the Generic Proceeding. LEI has recommended that several aspects of the status quo (such as adjusting the deemed capital structure only when there is a significant change in risk profile, not considering the ownership structure of the utilities in the cost of capital determination, and the updating frequency of key cost of capital parameters) be retained. However, the findings suggest that Ontario utilities and consumers may benefit from modifications to the current approaches, such as determining base return on equity ("ROE"), debt interest rates, and carrying charges allowed for the cloud computing deferral account.

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term index"), and the OEB, under contract, obtains this yield rate from PC Bond Analytics, a business unit of FTSE.[45]

The rates are reviewed quarterly, and updated only if the formulaic approach results in a change in interest rates of 25 bps or more.[46,47]

2.5.6 Cloud computing deferral account

Effective December 1st, 2023, per the Accounting Order (003-2023), the OEB implemented a generic deferral account that records the incremental costs, net of savings, of cloud computing implementation. The recorded costs are subject to OEB's approval in the utilities' respective subsequent rate proceedings for each utility.[48] Incremental costs are costs outside of what is embedded in rates i.e. when amounts are recorded, they should represent impacts that are more than what utilities are already compensated for.[49]

Prior to the cloud computing accounting order, the OEB did not distinguish the accounting treatment for cloud computing related operating/capital expenses and general operating/capital expenses.

To compensate for the additional risks and benefits (if any) associated with the change in methodology, the OEB aims to determine in this Generic Proceeding what type of interest rate, if any, is warranted for the above deferral account.

2.6 Historical context and timeline of key relevant events

Since 2006, there have been a number of key events related to cost of capital issues.

With regards to setting ***prescribed interest rates*** for DVA and the CWIP account, the current methodology has been in place since 2006.[50]

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[45] OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006.

[46] Ibid.

[47] For instance, the approved deferral and variance accounts ("DVA") interest rate of 5.49% for Q4 2023 was retained in Q1 2024 and Q2 2024, as interest rate was relatively stable during that period and had not changed by 25 bps or more.

[48] OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

[49] OEB. Q&A: Cloud computing implementation. Costs generic deferral variance account. February 15th, 2024.

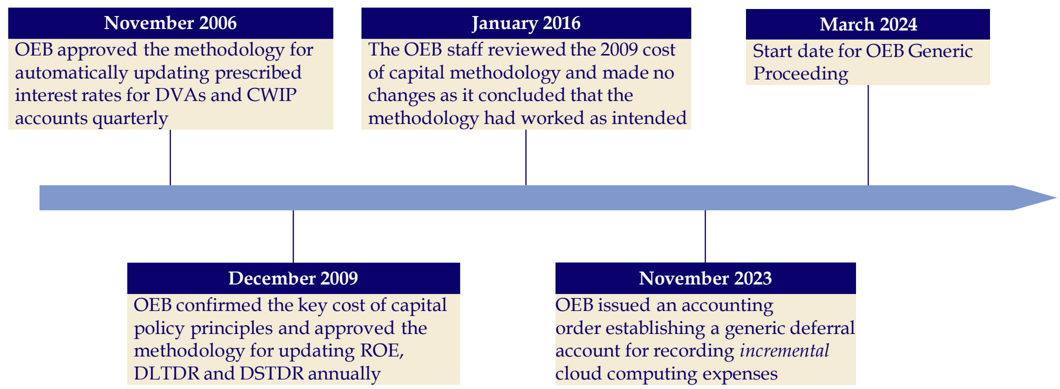
[50] In June 2020, the OEB decided to set the 2020 Q3 prescribed interest rates for DVA using a different approach from the methodology approved in 2006. This was done without consultation to expeditiously respond to *the unprecedented state of emergency arising from the COVID-19 pandemic*. The OEB used the average of the 2020 Q2 DVA interest rate and the 2020 Q3 DVA interest rate, both calculated with the OEB's approved methodology in 2006, as the final 2020 Q3 DVA interest rate. The decision was expected to smooth the impact of the COVID-19 pandemic, and align with the average of AA-, A-, and BBB-rated Canadian Corporate bond yields since May 2020.[50] However, following the decision, the OEB received comments from several intervenors against

As for setting ***cost of capital parameters***, the OEB continues to utilize the methodology approved in 2009. In 2016, a review[51] by OEB staff concluded the methodology continues to *work as intended*.

With regards to ***deferral account for cloud computing costs***, the accounting order for establishment of a generic deferral account to record incremental cloud computing costs was issued by the OEB in November 2023.

The timeline is summarized below in Figure 6.

Figure 6. Timeline of key events relevant to the Generic Proceeding



The subsequent sections briefly discuss key developments associated with this timeline.

2.6.1 Approval of accounting interest rates methodology for regulatory accounts (2006)

In May 2006, the OEB announced its plan to implement a formulaic approach for setting interest rates used by Ontario natural gas utilities and electricity distributors for regulatory accounts under the USoA.

The OEB Staff proposed a prescribed one-year interest rate for deferral and variance accounts based on the one-year Canada treasury bill and a two-tier approach for CWIP. For CWIP, the OEB Staff stated that *some utilities who use short-term financing during the construction phase, replace it with mid-term financing when the completed asset is placed in service*, while *other utilities finance construction as part of their general borrowing program or from equity*.[52]

Staff noted that calculating a blended rate on a utility-specific basis is *burdensome for utilities to constantly determine this rate for their utility*, and monitoring all regulated utilities' individual rates

the decision. Considering the comments, in July 2020, the OEB decided to re-establish the 2020 Q3 DVA interest rate using the methodology approved in 2006 and continued this practice since. Source: OEB. 2020 Q3 Prescribed Interest Rates. June 16th, 2020.

[51] OEB. OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

[52] OEB. EB-2006-0117. Board Staff Proposal Paper. Interest Rates for Regulatory Accounts of Utilities. May 26th, 2006. Page 8.

is *not practical for the Board*.[53] As such, the OEB Staff proposed to use two market-based proxy rates, depending on the length of the construction period. Specifically, the OEB Staff proposed interest rates for construction projects for:

(i) up to one year to be based on the one-year Canada treasury bill rate, and

(ii) more than one year to be based on the FTSE mid-term index[54]

The OEB opted for different proxy rates in its decision.[55] As mentioned earlier, for DVAs, the OEB approved an interest rate equal to the three-month bankers' acceptance rate plus a fixed spread of 25 bps. The OEB linked the interest rates for DVAs to a short-term interest rate *due to the temporary nature of the accounts to which they relate and disposition of account balances in rates over a relatively short period of time*.[56]

For CWIP, *for ease of administration and record keeping by users,*[57] the OEB approved an interest rate equal to the FTSE mid-term index, applicable to all projects under construction, regardless of the construction period.

As described above in the summary of the status quo, the two prescribed rates are reviewed quarterly and updated if the change is 25 bps or more.[58]

2.6.2 Review of cost of capital policies for Ontario (2009)

In the *Report of the Board on Cost of Capital and 2nd Generation Inventive for Ontario's Electricity Distributors*, dated December 20th, 2006 ("2006 Report"), the OEB adopted a modified capital asset pricing model ("CAPM") methodology using an equity risk premium ("ERP") approach.[59] The formulaic approach resulted in ROE being determined based on a Long Canada Bond Forecast ("LCBF") rate plus an ERP.[60]

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[53] Ibid.

[54] OEB. EB-2006-0117. Board Staff Proposal Paper. Interest Rates for Regulatory Accounts of Utilities. May 26th, 2006.

[55] OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006.

[56] OEB. EB-2006-0117. Board Staff Proposal Paper. Interest Rates for Regulatory Accounts of Utilities. May 26th, 2006. Page 3.

[57] OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006. Page 9.

[58] Ibid.

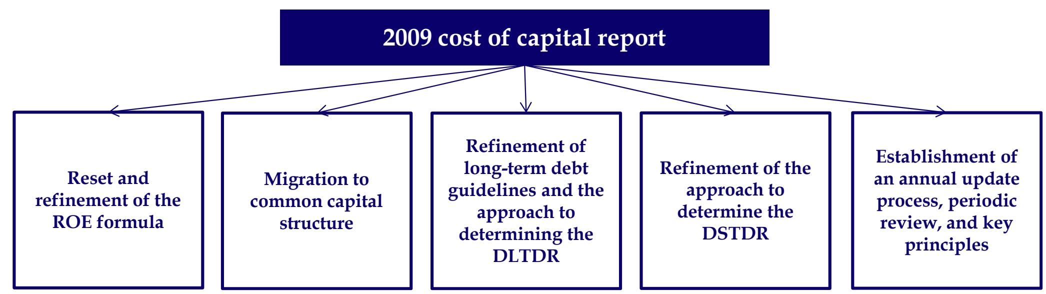
[59] The OEB also considered other ROE estimates from participants based on CAPM, discounted cash flow ("DCF") approach, and Comparable Earnings ("CE") approach. However, it decided to retain its existing ERP-based approach, which resulted *in a return sufficient for distributors to continue to attract capital*. Source: OEB. Report of the Board on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors. December 20th, 2006.

[60] OEB. Report of the Board on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors. December 20th, 2006.

The formulaic approach for determining the cost of capital parameters, i.e., ROE, DLTDR, and DSTDR, was selected given the significant number of regulated utilities under the OEB's jurisdiction.[61] The OEB noted that the formula-based approach *reduces the need for complex, annual risk assessments, while still reflecting major changes in the capital markets*, and hence *is a practical necessity in Ontario, given the large number of rate regulated entities.*[62]

In February 2009, the OEB initiated a consultative process in reviewing its cost of capital policies as set out in 2006,[63] which culminated in a policy report issued in December 2009. The report set out the OEB's updated approach and methodologies to determine the cost of capital. In particular, the report refined the OEB policies in five ways, as shown in Figure 7 below.

Figure 7. Key components of 2009 cost of capital report



Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

The five approaches are briefly discussed below.

Reset and refinement of the ROE formula:

In 2009, the OEB concluded that *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.*[64]

The OEB determined that the LCBF continues to be an appropriate base as set out in the 2006 Report to begin the ROE calculation. Based on the ERP recommendations derived from multiple approaches that were provided by participants in the consultation, the OEB determined an initial ERP of 550 bps, which included an implicit 50 bps for transactional costs, to be appropriate.

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[61] The OEB regulated over 80 utilities (primarily electricity distributors) in 2009. As of December 2022, the OEB regulated over 60 utilities.

[62] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009. Page 27.

[63] The ROE formula set out in the 2006 report is $ROE_t = 9.35\% + 0.75 \times (LCBF_t - 5.50\%)$.

[64] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009. Page i.

As described earlier in the status quo section, the resulting base ROE was determined to be 9.75%, assuming a base LCBF yield of 4.25%.[65,66] In addition, the ROE formula was refined to reduce sensitivity to changes in government bond yields driven by monetary and fiscal conditions which are not reflective of changes in the utility ROE. To make periodic adjustments to the base ROE, the OEB considered an LCBF spread, and a utility bond spread in the formula, subject to a 0.5 adjustment factor (as illustrated in Figure 3 earlier).[67]

Migration to a common capital structure

The OEB decided that the capital structure of 60% debt and 40% equity, initially determined in 2006, remained appropriate for electricity distributors and transmitters. The capital structure would be determined on a case-by-case basis for electricity generators and natural gas utilities.[68]

The capital structure for OEB-regulated entities has been relatively steady over the last two decades. The equity thickness currently approved by the OEB for various regulated entities is shown in Figure 8.

Figure 8. OEB allowed equity thickness

Regulated entities	OEB approved equity thickness*
Electricity distributors and transmitters	40%
Electricity generation (OPG)**	45%
Natural gas distribution (Enbridge Gas)***	38%
Natural gas distribution (EPCOR Natural Gas)	40%

* The equity thickness for OEB-regulated entities, with the exception of Enbridge Gas and OPG, has remained unchanged since 2006.

** For OPG, the OEB reduced the allowed equity thickness from 47% to 45% in EB-2013-0321, following submissions from various participants contending that OPG's business risks had reduced relative to prior OEB assessment.

*** For Enbridge Gas, the OEB approved an increase in equity thickness from 36% to 38% applicable for 2024 rates in EB-2022-0200 (Order dated December 21st, 2023).

Source: OEB.

Refinement of long-term debt guidelines and the DLTDR formula

The OEB noted that it would primarily rely on the embedded or actual cost for existing long-term debt instruments with respect to the determination of the DLTDR.[69] Third-party debt with a fixed

[65] Ibid.

[66] Base ROE = Base LCBF + ERP.

[67] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

[68] Ibid.

[69] Ibid.

3 Principles and approach

3.1 Principles

LEI has closely considered several underlying principles and objectives formulating recommendations in this report. These include:

- Cost of capital principles adopted by the OEB;
- Regulatory accounting principles adopted by the OEB; and
- OEB's mission and mandate.

LEI then synthesized five guiding principles consistent with this source material.

Cost of capital principles

With regards to the issues related to the cost of capital parameters, the OEB confirmed six key regulatory principles with respect to its cost of capital policy in its 2009 report (*EB-2009-0084)*, which are described below.[85]

1) **Fair Return Standard ("FRS"):** The FRS establishes a legal framework for setting a fair and reasonable return on capital for regulated electricity and gas utilities, as described in the text box below.

The Fair Return Standard ("FRS")

The FRS was articulated by the National Energy Board ("NEB") in its *RH-2004 Phase II Decision* (related to TransCanada PipeLines Cost of Capital), when it stated that three requirements must be satisfied to determine a fair and reasonable return on capital:

a) **Comparable investment standard**: 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;

b) **Financial integrity standard**: should enable the financial integrity of the regulated enterprise to be maintained; and

c) **Capital attraction standard:** should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions**.**

Source: NEB. RH-2-2004. Phase II Reasons for Decision, TransCanada PipeLines Limited cost of capital. April 2005.

It is important to note that [*m]eeting the standard is not optional; it is a legal requirement*.[86]

2) **The overall ROE must be determined solely on the basis of a company's cost of equity capital**, regardless of equity ownership, and any resulting rate increase must be an irrelevant consideration in determining the appropriate ROE for regulated utilities. The Federal Court

[85] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

[86] Ibid. Page i.

of Appeal established the principle in the case *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*.[87]

3) **Efficient amount of investment:** the cost of capital has to be determined to ensure that an efficient amount of investment occurs in the public interest to balance the impacts on both customers and shareholders (i.e., not so high that the Ontario consumers are disadvantaged, and not so low that the regulated utilities do not have sufficient incentive to make investments that are in the public interest).

4) **Predictability, transparency, and stability** in OEB decisions and outcomes so that investors, utilities, and consumers have reasonable confidence in making long-term decisions.

5) **Systematic and empirically based approach:** the OEB's methodology should be systematic, relying on economic theory and empirically derived from objective, data-based analysis.

6) **Minimize the time and cost of administering the framework**, particularly because the OEB has to determine the appropriate cost of capital for more than 60 regulated utilities. Costs imposed on regulated entities and the OEB should not exceed the available benefits, which can be met through a simple process that not only reflects the concerns of relevant parties, but also reduces process requirements.

Regulatory accounting principles

With respect to issues related to regulatory accounting (related to 'prescribed interest rates' and 'cloud computing deferral account'), LEI was guided by the established regulatory principles and practices laid out by the OEB in Accounting Order (003-2023), which are reproduced in the text box below.

OEB established principles and practices related to regulatory accounting

The accounting and regulatory reporting requirements should:

a) be based on sound regulatory principles including ***fairness, minimizing intergenerational inequity and minimizing rate volatility***;
b) ***balance the effects on both customers and shareholders*** when taking into account financial accounting requirements; and
c) be primarily driven by the objective of ***just and reasonable rates***.

Source: OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

[87] The NEB established a mechanism to automatically adjust the ROE (the 1995 decision). In 2001, TransCanada PipeLines Ltd. ("TransCanada") applied for a review of the 1995 decision and the NEB rejected the TransCanada's proposed new methodology for determining cost of capital and determined to continue using the adjustment mechanism set out in the 1995 decision. TransCanada then filed an appeal regarding the NEB's decision but failed to show that the NEB erred in taking customer interests into account when determining the rate of return on capital that it would allow TransCanada to earn. Source: TransCanada PipeLines Limited v. National Energy Board, 2004 FCA 149.

OEB mission and mandate

The outcome of the Generic Proceeding will affect the rates paid by residential and business consumers for electricity and gas services. As such, the recommendations in this report aim to protect consumer interests and ensure fairness to both consumers and utilities, consistent with the OEB's mission and mandate described in the text box below.

OEB's Mission and Mandate

The OEB's mission is to *deliver public value through prudent regulation and independent adjudicative decision-making which contributes to Ontario's economic, social and environmental development.*

As required under provincial legislation, the OEB's mandate is to regulate Ontario's energy sector. The OEB has regulated the natural gas sectors since 1960 and the electricity sector since 1999.

For consumers, the OEB's mandate includes:

- Protecting the interests of consumers by setting the rates and prices that utilities can charge;
- Providing the information consumers need to better understand the rules protecting them and their responsibilities;
- Protecting consumers' interests in retail electricity and natural gas market; and
- Addressing the particular needs of low-income consumers through the establishment and oversight of utility customer service rules and delivering financial assistance programs.

For industry, the OEB's mandate includes:

- Setting the delivery rates for electricity and natural gas utilities and monitoring their financial and operational performance;
- Approval of new electricity transmission lines and natural gas pipelines that serve the public interest;
- Approval of mergers, acquisitions, and dispositions by electricity and natural gas utilities;
- Setting the payments to OPG for electricity generated by its regulated nuclear and hydroelectric generation facilities;
- Establishment and enforcement of codes and rules to govern the conduct of utilities and other industry participants; and
- Licensing entities in the electricity sector and natural gas marketers.

Source: OEB. Mission and mandate. Accessed on April 17th, 2024.

Considering the abovementioned principles, LEI has devised five overarching principles to evaluate its potential alternatives and arrive at its final recommended approach. Overall, LEI proposes evolutionary rather than revolutionary changes in response to the issues identified in the Generic Proceeding. The principles include the following:

1. ***Meeting the FRS***, which is a legal requirement;

2. ***Simple to administer relative to the status quo***, i.e., the costs (if any) of transitioning away from the status quo and administering the recommended alternative are reasonable;
3. ***Transitioning away from the status quo only if the associated benefits are material*** as there is limited merit in modifying aspects of the methodology that have worked well;
4. ***Fairness in approach to consumers and utilities***, consistent with the OEB's mission and mandate, to ensure efficient investments; and
5. ***Predictability and transparency*** in the recommended approach to ensure that the outcomes from the proposed methodology are relatively stable over a long-term time horizon.

3.2 Approach

In Section 4, LEI presents recommendations for each issue in OEB's approved Final Issues List. For each substantial issue, LEI has adopted the following four-step approach:

- **Step 1 - Status quo:** briefly describes OEB's current practice.
- **Step 2 - Relevant jurisdictional review and/or literature review:** reviews relevant regulatory actions and decisions in select jurisdictions regarding the issue to provide insights relevant to Ontario. For issues where literature review is more relevant, LEI has presented relevant literature for the issues in question.
- **Step 3 - Potential alternatives (for approaches associated with relevant issues):** evaluates potential alternatives based on the findings in Step 1 (status quo analysis) and Step 2 (relevant jurisdictional analysis). LEI ***did not aim to present all possible alternatives*** but has presented alternatives that the OEB and other participants in the Generic Proceeding may find most useful to consider.
- **Step 4 - Recommendations:** a recommended approach was chosen from the list of evaluated alternatives, considering principles outlined in Section 3.1, with primary consideration of the FRS for issues related to the cost of capital.

3.2.1 Selection of jurisdictions

The jurisdictional review associated with Step 2 provides an understanding of relevant regulatory actions and decisions, highlighting approaches and lessons learned that may be unique to and/or particularly relevant to the Ontario context.

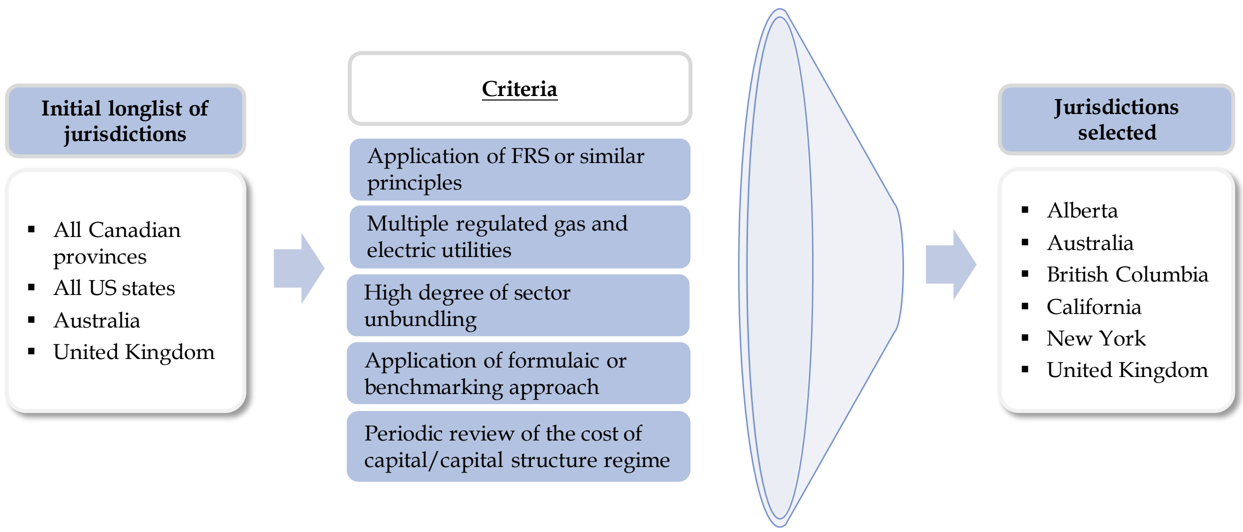
LEI's criteria in selecting jurisdictions for this report include:

1. ***application of FRS or similar principles*** in the determination of the appropriate ROE;
2. jurisdiction with ***multiple regulated gas and electric utilities***;
3. ***high degree of sector unbundling***, particularly with regard to the generation sector;

4. ***application of a formulaic or benchmarking approach*** to determining the cost of capital parameters; and
5. ***periodic review*** of the cost of capital/capital structure regime.

LEI began with a long list comprising US states, Canadian provinces, the United Kingdom ("UK"), and Australia. As shown in Figure 9 below, after applying the five criteria listed above, LEI selected six jurisdictions for further study: Alberta, Australia, British Columbia ("BC"), California, New York ("NY"), and the United Kingdom ("UK").

Figure 9. Selection of jurisdictions for further study



In addition to the North American jurisdictions, LEI included the UK and Australia because they have similar regulatory regimes to Ontario, and the cost of capital methodology adopted in these countries can provide valuable insights for Ontario. For instance, regulators in both these jurisdictions frequently review cost of capital parameters and provide thorough reasons for their decisions.

A summary of the selected jurisdictions is shown in Figure 10 below.

Figure 10. Summary of selected jurisdictions

Jurisdiction	2023 Population (millions)	2023 Electricity demand (TWh)	Number of regulated electric and gas utilities	Application of FRS or similar principle	Cost of capital approach	Cost of capital/capital structure review frequency
Alberta	4.8	86	21	FRS	Uniform formula across sectors applied since 2004 (discountinued in 2009)	Review every 5 years, subject to mid-term reopeners; ROE updated annually
Australia	26.8	188	43	An unbiased estimate of the expected efficient return, consistent with the relevant risks involved in providing regulated network services	Uniform formula across sectors applied since 2018	Reviewed every 4 years; Cost of debt updated annually, but not other parameters
British Columbia	5.5	65 (2019)	18	FRS	Benchmark*	Not scheduled
California	39.1	288 (2022)	6	Fair and reasonable rate of return** on capital investments	Case by case; A uniformCCM has been adopted since May 2008 for large utilities to automatically adjust their cost of capital parameters, not applicable for small utilities	Reviewed every 3 years
New York	19.6	144	18	Fair and reasonable rate of return on capital investments	Case by case; Bill A07502 has been introduced in May 2023 and referred to the Committee on Energy in January 2024 to establish a single rate of return on equity for all regulated utilities based on the generic financing methodology, but has not passed as of Apirl 23rd, 2024	Not scheduled
United Kingdom	67.6 (2022)	310	841	Fair return*** on utilities' activities while controlling the end cost to consumers	Formulae varied for different sectors applied since 2013	Reviewed every 5 years; Cost of debt updated annually, but not other parameters
Ontario	15.8	137.1	70+	FRS	ROE updated annualy and uniformly applicable for all utilities; Capital structure adjusted based on sector-specific risk profile	Review methodology every 5 years; ROE updated annually

* The benchmark methodology requires the BC Utilities Commission ("BCUC") to designate a Benchmark Utility and set cost of capital parameters of the Benchmark Utility. The BCUC then uses the Benchmark Utility as a reference to set cost of capital parameters of other regulated utilities by adjusting various risk factors. Source: BCUC.

** The principle of a fair and reasonable rate of return was established in the *Bluefield* and *Hope* decisions of 1923 and 1944, respectively. *Bluefields* states that *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*; *Hope* states that *the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks, and should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital*. Source: US Supreme Court.

*** The return should properly reflect the risks faced in the business and prevailing financial market conditions. Source: Office of Gas and Electricity Markets ("Ofgem")

A subset of the shortlisted jurisdictions is reviewed for each of the issues discussed in Section 4, depending on the respective issue and its relevance. Furthermore, where appropriate, LEI has included references to jurisdictions other than the six jurisdictions shortlisted in Figure 9.

3.2.2 Impact of the energy transition on the cost of capital

The term "energy transition" refers to a shift from an energy system that primarily relies on fossil fuel-based energy sources (such as natural gas, coal and oil) to net zero-emitting renewable energy sources (such as batteries, solar and wind power, and carbon capture and storage). Electrification of heating and transportation is often a large part of such policies, with impacts on regulated utilities in both the electricity and gas sectors. The pace of technological change is also impacting how and when customers consume (and sometimes generate) electricity.

However, while the energy transition is bringing dramatic changes to the sector as a whole, the focus when considering cost of capital implications is not whether and how fast the industry is changing but whether, for regulated businesses, the volatility of net cash flows is changing or there is an increased risk of inability to attract capital or recover associated investments. Neither appears likely in the forthcoming regulatory period. This is because the pace of change remains measured, and regulated utilities can use various regulatory mechanisms such as DVAs, Z factor, I factor, and off-ramp mechanisms to manage net cash flow volatility (if any).

By design, regulated entities face less risk than competitive businesses. Existing regulatory mechanisms address load fluctuations, capital recovery, and unforeseen events, whether caused by energy transition or not. Given that ratemaking processes directly deal with these issues and equity thickness is the lever used to address differences between regulated sectors (see Section 4.2.4 wherein LEI has recommended adjusting equity thickness as the appropriate lever for addressing material changes in risk profile), LEI does not believe energy transition issues are a large driver in reviewing the process of setting the cost of capital.

methodology to estimate the MRP. While some practitioners incorporate forward data into their equity return analysis, LEI believes forwards are too short-term and become less liquid in out years. LEI uses historical data, weighted towards more recent market experience.

The two other issues when considering MRP include the period of historical returns to consider and whether to consider MRP based on US or Canadian markets. In Figure 41 below, LEI has presented six options for considering MRP and the resulting CAPM ROE (utilizing a 5-year beta of 0.69 and a risk-free rate of 3.19%).

Figure 41. Six options for determining MRP and the resulting CAPM ROE for each option

MRP variables	Risk-free rate (R_f)	Beta	MRP	ERP (Beta * MRP)	CAPM ROE (R_f + ERP)
1928-2023 S&P 500 total returns - US 10-year treasury bond yields	3.19%	0.69	6.54%	4.53%	**7.72%**
1984-2023 S&P 500 total returns - US 30-year treasury bond yields			7.12%	4.92%	**8.11%**
1994-2023 S&P 500 total returns - US 30-year treasury bond yields			7.28%	5.03%	**8.23%**
2004-2023 S&P 500 total returns - US 30-year treasury bond yields			7.52%	5.20%	**8.39%**
2014-2023 S&P 500 total returns - US 30-year treasury bond yields			10.16%	7.03%	**10.22%**
2004-2023 S&P/TSX total returns - 30-year GoC bond yields			2.81%	1.94%	**5.14%**

Note: LEI's preferred CAPM ROEs are highlighted in green.

Sources: S&P Capital IQ, Statistics Canada, St. Louis Fed, NYU Stern.

LEI believes that CAPM ROE based on Canadian market data (5.14%) does not reflect investors' expected equity returns. The eight major pension funds in Canada (informally known as the Maple 8) allocate only about 25% of their portfolio to domestic Canadian investments, which indicates that investors are more likely to consider their MRP opportunity costs based on the US MRP.[314,315] As such, LEI prefers CAPM determined using US MRP.

Regarding the historical period to consider when determining the appropriate MRP, LEI prefers longer term averages (at least 10 years) as year over year MRP tends to be volatile (see Figure 42 below).

[314] Omers. Terms Explained: Pensions. November 12th, 2021.

[315] The Globe and Mail. Opinion: Pension funds need to seek out more investments in Canada. November 30th, 2023.

methodologies. A summary of methodologies used in other jurisdictions is shown in Figure 45 below.

Figure 45. ROE methodologies used in other jurisdictions

Jurisdiction	CAPM	DCF	ERP	CE*	Combined
Alberta			x		
Australia	x				
British Columbia					x (CAPM, DCF, and ERP)
California					x (CAPM, DCF, and ERP)
Federal Energy Regulatory Commission					x (CAPM, DCF, and ERP)
Florida					x (CAPM and DCF)
Georgia					x (CAPM, DCF, ERP, and CE)
Illinois					x (CAPM and DCF)
Michigan					x (CAPM, DCF, and ERP)
New York					x (CAPM and DCF)
North Carolina					x (CAPM, DCF, and ERP)
Ohio					x (CAPM and DCF)
Ontario			x		
Pennsylvania					x (CAPM and DCF)
Texas					x (DCF and ERP)
United Kingdom	x				

* CE stands for 'Comparable Earnings' approach.

Sources: S&P Capital IQ, past rate cases.

This results in a base ROE of 9.60%, which is an average of 8.95% (CAPM approach), 10.77% (DCF approach), and 9.09% (ERP approach). The ROE can be updated annually based on the formula described in alternative #5.

The results from the options presented by LEI are summarized in Figure 46 below.

Figure 46. Summary of ROE options

Alternative #	Description	Base ROE value	LCBF adjustment factor	Corporate bond yield spread adjustment factor
1	Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads, and adjustment factors based on current data	9.09%	0.39	0.33
2	Same as #1 except determining base ROE with the discounted cash flow ("DCF") approach instead of the ERP approach	10.77%	0.39	0.33
3	Same as #1 but determination of adjustment factors using multivariate regression analysis	9.09%	0.26	0.13
4	Determination of base ROE using CAPM and adjustment of ROE using CAPM formula parameters	**Average: 8.95%** High: 10.22% Low: 8.23%	N/A	N/A
5	Determination of base ROE using CAPM, with ROE updated using adjustment factors determined in #3	**Average: 8.95%** High: 10.22% Low: 8.23%	0.26	0.13
6	Determination of an average base ROE from CAPM, ERP and DCF methodologies, with updating of ROE based on #3	9.60%	0.26	0.13

Notes:

(i) LEI recommended alternative is highlighted.

(ii) The ROEs allowed by US regulators in 2022 and 2023 rate cases have ranged between 7.85% and 11.45% (Source: S&P Capital IQ).

(iii) For each alternative presented above, the base ROE value and adjustment factors are to be updated after five years; $LCBF_t$ is to be updated annually in October/November of every year as per the methodology described in Figure 26 (latest 30-year GoC bond yield forecasts for the subsequent year from major Canadian banks); $UtilBondSpread_t$ is to be updated annually in October/November of every year based on the 12-month average (data from October of the previous year to September of the current year) for the BVCAUA30 BVLI Index.

Potential alternatives for frequency of updating ROE

The OEB may consider the following options for updating ROE:

1. **Status quo:** ROE is updated annually using a formulaic approach. The prevailing ROE during the year of rate case filing is applicable for the entire IRM period.

2. **Set ROE for the five upcoming years** and update the ROE every five years (for the next five years) based on new data.

4.10.4 Recommendations

LEI prefers to use CAPM for base ROE determination (alternative #5). Beta is a useful indicator in measuring sector-specific risk (which the ERP methodology lacks). Due to the stable returns

allowed by regulators, the regulated utility industry is a relatively low-risk industry.[319] A beta is necessary to determine the appropriate ERP for regulated utilities. CAPM, when used judiciously, also meets the FRS as the ERP is determined specifically to compensate for additional risk over the risk-free rate.

A key issue with the DCF (constant growth and multi-growth) approach to estimating ROE is that it primarily relies on subjective future earnings growth estimates. Furthermore, DCF and risk premium methodologies are less used by actual investors to estimate ROE outside of regulatory proceedings.

While LEI acknowledges that the DCF method is sometimes used for determining ROE, its reliance upon estimates of future growth of cash flows is a key weakness, as it relies entirely on growth yield estimates, which typically tend to overestimate the ROE. Estimates of future growth of cash flows can be unreliable: studies have shown that a naïve random walk (in which a given year's projected earnings are equal to the previous year's earnings plus random white noise) provides as accurate a forecast of long-term future earnings as analysts' forecasts.[320] Earnings forecasts can be inaccurate, tend to overvalue the cost of equity, and are consistently overly optimistic.[321] While the DCF methodology is a very widely used tool for valuing a company, the target ROE is an input rather than an output. When valuing a company or an asset using DCF methodology, a terminal value is frequently considered to capture the value of a business beyond the projection period (typically 10 to 30 years) in a DCF analysis. As such, DCF methodology is poorly suited for ROE determination using only a 3-5 years forward-looking outlook and is likely to result in an unrepresentative estimate of the ROE.

LEI believes that using CAPM to estimate ROE is the most reasonable method because it is among the most commonly used valuation methods, with a widespread understanding of the assumptions/inputs involved and the ability to adjust results to account for unsystematic or company-specific risks.[322]

CAPM takes the systematic risk, i.e., the risk inherent in the market, into account through empirical analysis of historical data. While it is true that CAPM relies on the quality of input data and assumptions, reliance on a well-defined range from a historical dataset is a sensible approach

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[319] S&P Global Ratings classifies regulated utilities as a 'low risk' sector in cyclicality assessment and as 'very low risk' in competitive risk and growth environment assessment, as well as global industry risk assessment. Source: S&P Global Ratings. Updated: January 25th, 2021.

[320] Michael Lacina, B. Brian Lee and Zhao Xu, *Advances in Business and Management Forecasting*, at 77–101 (Kenneth D. Lawrence, Ronald K. Klimberg eds., Emerald Grp. Publ'g Ltd. 2011).

[321] R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts." *Journal of Business Fin. & Accounting*, 725–55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan. "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings." *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates." *Journal of Finance.* 643−84 (2003).

[322] Bruner, Robert & Eades, Kenneth & Harris, Robert & Higgins, Robert. (1998). Best Practices in Estimating the Cost of Capital: Survey and Synthesis. Financial Practice and Education. 8.

Curriculum Vitae

AJ GOULDING

President, London Economics International LLC

KEY QUALIFICATIONS:

In his role as president of London Economics International LLC, AJ Goulding manages a growing international consulting firm focused on finance, economic, and strategic consulting to the energy and infrastructure industries. In addition to serving as a sector expert in electricity and gas markets, his responsibilities include project management, marketing, budget and financial control, and recruiting. AJ also serves as an Adjunct Associate Professor at Columbia University, where he teaches a course on electricity market design and regulatory economics while also supervising graduate workshops.

With over thirty years of experience in evolving electricity and natural gas markets, AJ's diverse background enables him to work effectively in both emerging markets and OECD countries. In North America, AJ has been articulate in describing market relationships between wholesale power marketers, merchant plants, aggregators, and the existing investor-owned utilities. In emerging markets, AJ has considerable experience dealing with the challenges of mixed private and public ownership, difficulties in creating credit-worthy distribution and retail entities, and the realities of line losses, unreliable fuel deliveries, and politicized labor relations.

AJ began his career performing natural gas market analysis for the ICF Resources subsidiary of ICF Kaiser International. Later, he lived for two years in New Delhi, India, where he advised the United States Agency for International Development (USAID) on electric power sector restructuring in India. He continued his work on India while pursuing his MA at Columbia University, leading to the publication of an article on Indian privatization. Simultaneously, he researched the process of power sector reform in Pakistan, contrasting it with the Indian experience. Upon completion of his MA, AJ served as business development associate for Citizens Power LLC, a top ten US wholesale power marketer. He then moved to London Economics, where he has held roles of progressively increasing responsibility.

EDUCATION:

Earlham College, Richmond, Indiana, B.A. in Economics, 1991. College honors, scholar-athlete, public service graduate fellowship.

Columbia University, New York, New York, M.A. in International Business, 1997. Foreign Language and Area Studies fellowship, Cordier prize.

EMPLOYMENT RECORD:

From: 1996 **To:** present
Employer: *London Economics International LLC, United States*
President (July 1999 to present), Senior Consultant (January 1998 to July 1999), Summer Associate (June 1996 to August 1996)

From: September 2003 **To**: present
Employer: *Columbia University*
Adjunct Associate Professor (2014 to present), Adjunct Assistant Professor (2003-2014)

From: 1997 **To**: 1997
Employer: *Citizens Power LLC; Boston, MA*
Associate

From: 1994 **To**: 1995
Employer: *USAID; New Delhi, India*
Energy Consultant

From: 1991 **To**: 1993
Employer: *ICF Resources, Inc.; Fairfax, VA*
Analyst

SAMPLE PROJECT EXPERIENCE:

The projects briefly described below are typical of the work AJ has performed throughout his career at London Economics, Citizens Power, USAID/India, and ICF Resources. AJ also serves as an adjunct professor at Columbia University, where he teaches a course in electricity market design.

Ontario-Related Work

Regulatory Economics (Ontario)

- ***Enbridge Gas capital structure expert:*** London Economics International LLC ("LEI") was engaged by the Ontario Energy Board ("OEB") as a cost of capital / capital structure expert to review Enbridge Gas' application for 2024 rebasing and 2025-2028 price cap plan. LEI's responsibilities include analyzing the evidence and assisting OEB staff in preparing interrogatories, independent expert evidence, and participating in the technical conference following the review of interrogatory responses

- ***Capital structure analysis for Ontario Power Generation ("OPG")***: LEI was retained by the OEB staff as capital structure expert in respect of OPG's 2022-2026 Payment Amounts Application (EB-2020-0290). As part of its engagement, LEI assisted in preparing interrogatories; and prepared an independent expert report following a detailed review of the analysis of risks set out in the application on the risks faced by OPG. LEI also responded to interrogatories with respect to its expert report.

- ***provided expert witness services:*** LEI was engaged by an international law firm to provide expert witness services in a legal dispute regarding interpretation of a Feed-in Tariff contract for a rooftop solar facility in Ontario

- ***provided expert witness services:*** LEI was retained by a renewable energy generator to provide evidence in a confidential legal proceeding, which ultimately reached a resolution satisfactory to the parties

- ***network tariff reform case studies:*** LEI supported Frontier Economics in preparing international case studies for the New Zealand Electricity Authority on network tariff reforms. LEI focused on two North American jurisdictions - Ontario and Texas

- ***supported gas supply RFP:*** on behalf of a client developing a new gas distribution utility in Ontario, LEI was engaged to develop and prepare a Request for Proposal ("RFP") for the physical supply and delivery of natural gas and related services. The RFP included an outline of the client's objectives, a description of the characteristics of the services the client was seeking, and the development of criteria used in evaluating proposals

- ***submission to Ontario LTEP consultations regarding value of capacity imports:*** On behalf of a large Canadian hydropower generator, LEI analyzed the potential economic benefits of the export of capacity and energy from Quebec to Ontario. The engagement included a review of the treatment of imports in capacity markets in the Northeast, an examination of the impact on capacity prices of imports, and a discussion of the reliability benefits that long term contracts for capacity imports provide. In addition, LEI discussed how Ontario can create a level playing field for clean energy imports relative to other potential future sources of supply in Ontario

- ***revenues to hydro portfolio in Ontario:*** for a large North American industrial company, AJ led the creation of a market study and report underlying the issuance of income trust securities. Tasks included multiple scenario analysis of merchant revenues, review of ancillary services revenues, and an examination of the Ontario hybrid market structure

- ***assessment of role of peaking plant in Ontario power sector:*** for Ontario government body, performed extensive scenario analysis to determine extent to which peaking plant should be a part of future procurement plans in the province; this analysis included assessment of revenues from ancillary services and of optionality

- ***impact of Ontario market changes on industrial consumers:*** for association of large power consumers in Ontario, assessed market trends and future entry and exit scenarios to determine long term price dynamics in the face of changes in government deregulation policies

- ***regulatory innovation***: AJ led the LEI engagement for the Ontario Energy Board ("OEB") to prepare a jurisdictional scan that looks at energy regulators and regulators of other sectors, as may be relevant, from around the world and identifies new objectives for regulators, new areas of regulatory oversight/authority, regulatory oversight of long-term planning, regulators' role in indigenous reconciliation, regulators' role in determining/defining the role of distributors, regulators' approaches to innovation and approaches to disruption by other sector regulators

- ***policy evaluation framework revision:*** AJ Goulding, President of London Economics International LLC ("LLC"), worked alongside John Todd, President of Elenchus Research Associates, Inc., to revise the Ontario Energy Board ("OEB")'s existing Policy Evaluation Framework, which is used to assess the effectiveness of proposed and existing OEB policies

- ***member of OEB's Advisory Committee on Innovation:*** AJ, as LEI's President, was selected to serve on the Ontario Energy Board ("OEB")'s Advisory Committee on Innovation, to assist the OEB in sharpening its focus on enhancing efficiency, cost effectiveness, innovation and value for electricity customers. The Committee, reporting directly to the Chair of the OEB, focused on identifying actions that a regulator can take that will support and enable cost effective innovation, grid modernization, and consumer choice to help inform regulatory policy development. The Committee's overarching goal was to support the OEB's embarkment on a process that would evaluate whether and how best to adapt regulation in order to keep pace with an evolving sector

- ***electric distribution sector resiliency:*** LEI was engaged by the Ontario Energy Board to analyze and define resilience and related policy questions as they apply to electricity distributors in Ontario within the context of climate change. LEI prepared a written report consisting of two key parts: (1) a description of current and anticipated future extreme weather impacts in Ontario as a result of climate change; and (2) a set of resiliency best practices, based on a review of approaches in other jurisdictions. LEI also presented its findings at a stakeholder workshop

- ***Ontario electricity market paper:*** on behalf of a respected Canadian think tank, LEI provided an assessment of the ways in which the Ontario electricity sector could be improved to increase economic efficiency and reduce costs for consumers over the long run

- ***cost of capital for regulated generating assets:*** provided expert testimony on behalf of the Ontario Energy Board regarding risk factors associated with Ontario Power Generating's prescribed assets, as well as creating a risk-return continuum on which power sector assets could be placed

- ***incentive-based contract design:*** for Ontario Power Authority, advised on provisions of power purchase agreement associated with incentives for optimization of production in peak periods for hydro facility owned by a major generator

- ***upstream capability to deliver conservation and demand management:*** for Ontario Power Authority, performed examination of capabilities of Ontario to provide necessary inputs to assure that Ontario meets is conservation and demand management targets; report incorporated into Integrated Power System Plan submission to OEB

- ***regulation of generation in Ontario:*** for Ontario Energy Board, AJ authored paper described the ways in which legacy assets of Ontario Power Generation could be regulated, including incentive regulation and a set of regulatory contracts. Deliverables included providing technical advisory during public workshop

- ***potential for regulation of retail market auctions:*** for Ontario Energy Board, AJ led engagement to review practice of regulatory oversight of load auctions to serve default supply across North America

- ***2nd generation PBR in Ontario:*** led Cdn. $1.5 million engagement focusing on design of second generation PBR in Ontario. Key components include estimating total factor productivity (TFP), determining appropriateness of yardstick competition, analyzing demand-side management programs in the context of PBR, and examining service quality indicators

- ***market power concerns in Ontario:*** determined concentration ratios for existing configuration of generation plant, developed set of recommended portfolios to minimize market power across all timeslots in hourly market in preparation for divestiture or other market power mitigation mechanisms

- ***strengthening utility accountability for reliability:*** LEI advised provincial regulator on the design and implementation of the benchmarking model for the Ontario's electricity distribution utilities. The objective of the project was to develop a custom model to benchmark reliability performance, and to develop reliability performance expectations to improve the utility accountability for reliability. The work was conducted in close cooperation with the working group that included utilities, industry associations, and customers. The work included also conduct of stakeholder workshops and presentations to the Board

- ***conducted independent evaluation review:*** LEI provided advisory services to assist the OPA in evaluations of applications made to the Aboriginal Renewable Energy Fund ("AREF") and the Aboriginal Transmission Fund ("ATF"). LEI provided advice and analysis related to the technical, financial and regulatory viability of each proposed project

- ***analyzed cost implications of Ontario's Green Energy Act:*** on behalf of the Official Opposition in Ontario, analyzed the cost implications of the government proposed 2009 Green Energy Act. This included costing of the feed in tariff program, interconnection costs, conservation and demand management initiatives and the implementation of the smart grid. The company presented key results in a press conference

- ***Industrial electricity rate economic impact study:*** LEI was engaged by an industry association for an Industrial Electricity Rate Economic Impact Study in Ontario's manufacturing sector. The scope of work consisted of review of current Ontario industrial electricity rates and rate designs; assessment of competitive electricity rate levels;

development of options to change rates in a manner consistent with rate setting principles that is beneficial to industrial consumers and the Province; quantification of economic benefits from appropriate rate adjustments; and consultation with relevant industry and government officials and experts throughout the project

- ***conservation and demand management (C&DM) in Ontario:*** wrote testimony related to the alternative ratemaking approaches available regarding C&DM; addressed innovative alternatives and compared and contrasted various schemes in the Ontario context

Asset Valuation and Transaction Advisory Work (Ontario)

- ***independent expert in Ontario:*** LEI was retained to act as an independent expert in a legal proceeding between a consulting firm and developers of a 300 MW wind project in Ontario. On behalf of the consulting firm, LEI prepared an expert report concerning the services the consulting firm provided to the wind developers, and how the fees for such services would be compensated in accordance with the terms of their services agreement

- ***examination of contracting processes in Ontario:*** on behalf of the Ontario Power Authority, met with over 50 stakeholder groups to determine potential ways in which contracting process for new supply could be improved. Engagement included assessing practices in other jurisdictions and review of standard offer processes

- ***due diligence support associated with the evaluation of the possible acquisition of a minority stake in a major Ontario transmission and distribution company:*** LEI prepared reports and analysis which contributed to the analytic framework for this proposed transaction, including analysis of the regulatory framework, review of impact of PBR on revenues, strategic issues, and the potential for revenue growth

- ***valuation of Ontario generating plants, including assessment of regional electricity markets:*** organized and implemented major modeling effort to determine potential value of generation stations in Ontario. Assessed impact of transmission constraints and restructuring efforts in neighboring markets on future wholesale market prices

- ***expert testimony in an Ontario litigation regarding electricity costs:*** LEI was retained to prepare expert testimony in an arbitration between two industrial customers in Ontario. The dispute relates to the calculation of electricity costs under a supply agreement between the two parties. As part of the expert testimony, LEI commented on the customer's participation in IESO-administered markets and programs to manage these electricity costs, including the Industrial Conservation Initiative.

Asset Valuation and Transaction Advisory Work

North America

- ***advised on battery storage project:*** LEI was engaged by a financial development bank to assess the technical adequacy and suitability of a battery energy storage project (in development) to be co-located with a hydroelectric facility and provide technical support in the drafting of financing documents required to reach financial close. As part of this process, LEI performed (i) an operating performance review of an existing asset; (ii) forecasts for energy prices, ancillary service prices, and energy storage modeling over a 25-year timeframe, as well as the development of a revenue profile for the target portfolio; and (iii) provided a detailed market report of the Alberta market.

- ***due diligence for the acquisition of a portfolio of PSH and NPD across the US:*** LEI was hired by a private equity firm to provide technical assistance and due diligence on the acquisition of a portfolio of hydropower projects located in multiple states across the US. The Projects consisted of a mix of run of river hydro and large pumped storage at various level of development. As part of its due diligence, LEI carried out a general review of the hydropower and pumped storage markets to evaluate the relative competitiveness of these technologies especially in markets with high renewables and storage penetration; LEI also developed a 20-year forecast of revenue streams for the relevant assets in the market of interests and reviewed the assets marketability post contract expiration. Finally, LEI reviewed key offtake contract to make recommendations on replicability (or lack thereof) of such contracts especially in highly competitive regions

- ***accreditation curve (Effective Load Carrying Capability) for a BESS:*** LEI was hired by a large electric utility to project an accreditation curve for a BESS under development in NYISO, amidst NYISO's proposed new accreditation rules. The goal of the study was to estimate over a 20-year horizon potential accreditation of the proposed Project based on its marginal contribution to the system reliability. The capacity credit (accreditation) was needed to derive the UCAP values the Project would be capable of offering in the NY capacity market

- ***evaluated peaker units in New England:*** London Economics International LLC (“LEI”) was retained to evaluate the economics of constructing peaking units in two possible existing New England hydro facilities. Specifically, LEI conducted an analysis on existing peaker technologies, the permits required, and determined how much investment would be justified to make the project economic.

- ***evaluated cost economics of installing energy storage technologies at existing hydro power plants in Massachusetts and New York:*** The analysis was conducted in three phases – phase 1 consisted of literature reviews and primary information collection (from manufacturers and 2service providers) on the available types of energy storage technologies and associated fixed and variable costs. Phase 2 consisted of an economic cost-benefit analysis of the least cost storage technologies to understand the viability of the investment. Phase 3 consisted of developing comprehensive criteria for selecting the energy storage manufacturer/service provider and presenting implementation recommendations.

- ***conducted PJM price forecasting:*** London Economics International LLC (“LEI”) was retained to provide forecasted energy and capacity prices as well as supply curves for a plant located in PJM’s SWMAAC region

- ***cost benefits analysis of US transmission line:*** for a utility in the northeastern US, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements. In the analysis, LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible

- ***review of risk management practices:*** LEI was engaged by the client to review its risk management practices and provide meaningful insights with regards to the risk management related issues. Analysis included quantification of the magnitude and probability of risks being faced, as well as research into the best practices of other similar organizations

- ***conducted a report on net metering programs in New Hampshire and New York:*** for a private equity power sector investor, LEI conducted a report on net metering programs to determine if the client's facilities would qualify. Project work included determining load at the sites, examination of net metering in the applicable regions, assessment of potential solar installation, exploration of installation options to determine which would be most suitable, and analyzing potential returns

- ***assessment of small hydro properties:*** as part of a retainer agreement with a growing private equity firm focused on the roll-up of small hydro properties, LEI performed a variety of supporting activities, including examination of forward markets, review of PPAs, assessment of renewable energy policies, and strategic analysis

- ***review of North American hydro assets:*** LEI was engaged by a large Canadian hydro generator to evaluate the potential renewable premium associated with its hydro assets in North America. LEI developed an economic model to project legacy Renewable Energy Certificate ("REC") prices in New York and New England. LEI also provided alternative methodologies such as projecting the premium based on forecasted carbon allowance prices and analyzing potential sales to large corporations on a voluntary basis

- ***analyzed current and future dynamics in the British Columbia power markets for of British Columbia power producers:*** topics analyzed included costs of independent power producers ("IPPs") relative to BC Hydro, uncertainty around future demand levels in BC, implications of moving away from use of Critical Water Year analysis in planning, risks and uncertainties regarding import availability, and the overall macroeconomic contributions of IPPs. LEI also analyzed the provincial government's Review of BC Hydro and provided an assessment

- ***wrote paper on investments by electric and natural gas utilities:*** LEI authored a paper on the successes and failures associated with international investment by electric and natural gas utilities for a major Japanese utility. The paper focused on the activities of over forty companies, both within North America and internationally

- ***developed several forecasts of the long-term Alberta electricity power pool prices (2010 to 2030) based on different market parameters and build decisions:*** the forecast also made special note of the effect on the market, if any, of the following conditions: (i) greenhouse gas legislation; (ii) increase in unconventional (shale) natural gas production; (iii) effect of the enactment of Bill 50; and (iv) effect on the market by external jurisdictions

- ***market analysis for a client interested in purchasing a portfolio of global generation assets:*** in this project, the LEI team, led by AJ, provided a market analysis of California, Mexico, and the Philippines. This market analysis included the following aspects: description of portfolio assets in the jurisdiction, supply/demand balance in the jurisdiction, regulatory framework, contract description and impact of competition on specific portfolio assets in the jurisdiction, indicative position of target asset on supply curve presently and in the future, impact of climate change and other environmental regulations, observations from material in dataroom, review of pool price projections, and remarks about the jurisdiction. In addition, LEI performed a 20-year price forecast for these markets, which was delivered in a spreadsheet form and incorporated into the management presentation

- ***advised Japanese company on potential US power sector acquisitions:*** reviewed project economics for multiple acquisition targets of Japanese investor. Tasks included providing long term revenue forecasts, reviewing motivations of sellers, providing insights on the associated market, and examining the role of hedge funds and private equity

- ***revenue forecast and financing advisory for renewables acquisition:*** for newly established private equity firm, managed acquisition process for small hydro and biomass site. Process included revenue forecasting, negotiating term sheets with banks, obtaining quotes for power purchase agreements, reviewing operating agreements, and overseeing all aspects of transaction process

- ***prices for merchant generators and IPPs:*** provided expert opinion on the extent to which value of a generating station could change over a 12 to 18 month period, based on historical analysis of price changes for individual generation assets as well as for generation asset portfolios

- ***biomass investment evaluation:*** on behalf of growing private equity investor, performed extensive analysis of economics of restart of several biomass plants in California and elsewhere. Tasks included PPA review, examination of permits, assisting in arranging financing, and examination of California market dynamics

- ***advised on purchase of small hydro station:*** for a newly established hydro-focused private equity investor, valued and performed regulatory review associated with successful purchase of a small hydro facility in Maine. Tasks including creating pro forma, reviewing material contracts, negotiating purchase and sale agreement, hiring operator, and monitoring ongoing performance

- ***bid for New York City gas and oil fired stations:*** for a major financial institution, AJ led a team of analysts in examining potential future revenues for a portfolio of peaking plants in

New York City. Assignment included using proprietary models to forecast future capacity and energy revenues, and the application of real option techniques to determine value of plant flexibility

- ***bid for PJM coal-fired power station:*** worked closely with private equity fund in creating deal team, preparing first round bid, and valuation of facility, including coal supply, environmental compliance, site options, and forecast of future revenues; helped to develop second round bid, including assisting in arranging financing and risk management

- ***collateralized debt obligations ("CDOs"):*** led projects associated with detailed statistical analysis of the underlying economics of CDOs associated with distressed debt in the power sector, and with examining whether such a CDO could have been launched in the wake of the Enron collapse

- ***valuation of New England based generation portfolio:*** worked with potential acquirer of New England's largest generation portfolio to determine the costs of ongoing obligations associated with the portfolio, provide an understanding of long term market dynamics, and assess value of overall portfolio, including revenue forecasts and review of market rules

- ***valuation of integrated IOUs:*** coordinated evaluation effort for acquisition of Southeastern US utility and of Ontario municipal electric utility; tasks included assessment of impact of PBR, calculation of difference in profits from generation portfolio under ratebase versus in open market, and analysis of ratebase settlement

- ***valuation and regulation of LNG facilities:*** assessed potential for combination of strategically situated LNG facility with US wholesale power marketer; for separate client, advised on third party access requirements for LNG facilities in the US and relevance to potential regulatory changes in Japan

- ***assessment of value of coal station contracts circa year 2000:*** developed analysis of value of contracts to bear costs and benefits associated with output from coal fired power stations in Alberta. Engagement involved considering only information known as of 2000, for inclusion in tax litigation case. Created pro forma valuation of the contracts as of 2000, including forecast costs and revenues, as well as opining on the appropriate cost of capital to be used

- ***price forecasts in key Canadian markets and associated export zones:*** provided long term electricity price forecasts in multiple engagements for key Canadian markets, including Alberta, British Columbia, and Ontario, as well as related export markets such as New York, Midwest ISO, and PJM. Results used by clients for obtaining financing and assessing contract pricing

- ***revenues to wind generators in Alberta:*** AJ led the examination of merchant revenues to a portfolio of existing and under construction wind generators in the province of Alberta. Tasks included review of market design issues, 20 year scenario analysis for merchant revenues, review of contract terms and conditions, and an examination of the potential for additional revenues from the sale of emissions reduction credits and renewable energy certificates. Deliverables included market study supporting issuance of income trust units

- ***advised on bid strategy for Mexican IPP:*** LEI assisted a large foreign utility in its bid strategy for acquisition of generating assets in international jurisdictions (across North America, Europe, and Asia). The LEI team led the market analysis for assets located in Mexico; more specifically, LEI analyzed a series of macroeconomic risks (including political, economic, and regulatory risks) likely to impact operations of the assets in the long run, performed a full due diligence review of the targeted assets, and developed forecast of the Mexican wholesale spot energy prices in order to determine future profitability of the assets.

- ***conducted water pricing in California:*** London Economics International LLC ("LEI") was retained to conduct a 30-year price curve for Metropolitan Water District of Southern California ("MET Water") in relation to a potential acquisition of a proposed desalination plant in California. The desalination plant's water rate specified in the draft Term Sheet of the Water Purchase Agreement is based on MET Water's prices plus avoidable charge, subsidy, and a premium. LEI reviewed the regulatory arrangements of MET Water, supply-demand dynamics in Southern California, and water pricing mechanisms used by MET Water. LEI also assessed the different key drivers for each component of the MET Water price. Lastly, LEI created a cost of service model and projected the MET Water prices for the next 30 years.

Asia and the Middle East

- ***commercial advisory services for expansion projects:*** LEI was engaged by a private client for commercial advisory services associated with 7 generation expansion projects in Saudi Arabia. To address the security of supply concerns, the client expects to sign Energy Conversion Agreements ("ECAs") on fast-track generation projects with counterparties. LEI's role is to assist the client across 4 milestones for each of the 7 projects: (i) Milestone 1: reviewing non-binding offers and financial models prior to ECA signing; (ii) Milestone 2: Assisting on ECA preparation and review of pertinent documentation; (iii) Milestone 3: Assistance post-ECA signing and submission of documents to lenders/banks; and (iv) Milestone 4: Assisting on Financial Close

- ***due diligence and valuation of engineering consulting firm:*** for a Middle Eastern investment fund, AJ led the evaluation of the acquisition of an engineering consulting firm with offices in the US, Europe, and the Middle East focused on the power sector; the project included creation of a pro forma for the business, evaluation of business prospects and strategy, and an examination of the relevant economic conditions and their impact on value

- ***assessment of plant pro formas and underlying market environment in six Asian countries:*** for leveraged buyout of major global IPP developer, assessed plant financial models, state of reform efforts, and potential for unbundling in Bangladesh, China, India, Philippines, Thailand, and Turkey

- ***valuation of Singapore generating asset:*** on behalf of a large Asian generating company, provided revenue forecasts from spot, retail, and vesting contracts for successful acquisition of Singapore generator. Analysis included review of repowering options, assessment of regulatory evolution, assessing the relevant cost of capital, and potential for strategic behavior; AJ later performed a similar exercise for a second Asian generating company also seeking to purchase a similar set of assets in Singapore, as well as subsequently assisting in analysis associated with refinancing of the acquisition performed by initial client

- ***modeling future Japanese electricity market dynamics:*** for a leading Japanese financial institution, led workshop and directed the creation of an interactive model of the Japanese electric power sector. Issues addressed included quantification of plant asset values under various market scenarios, an assessment of the potential for stranded costs, review of debt coverage ratios, and exploration of the evolution of transmission assets

- ***examination of markets and generation asset values in Mexico, Philippines, and California:*** assisted Asian IPP in assessing generating assets in Mexico and Philippines, as well as export potential from Mexican plants to the US; mandate included developing long run marginal cost forecasts for Philippines and Mexico, and providing detailed dispatch modeling of the California market

- ***valuation of generation and distribution assets in Philippines and the Caribbean:*** provided detailed analysis of regulatory trends in the Philippines and in selected Caribbean countries. Used regulatory filings, PPAs, and public information to develop a value for generation and distribution assets in these markets. Advised potential buyer on relative risk in each country examined, including country risk, regulatory risk, and fuel supply and load growth issues

Central and South America

- ***conducted overview of hydro-dominated market:*** LEI was hired to provide an understanding of the dynamics underpinning hydro-dominated power markets as opposed to thermal systems. As part of this project, LEI reviewed in details the dynamics and key drivers of energy markets in a sample of Latin America countries including Colombia, Panama, Brazil and Chile. Colombia was the point of focus of the report, in this respect LEI compared and contrast several aspects of the Colombian markets to other jurisdictions and created a scoring card to evaluate Colombia against similar jurisdictions

- ***valuation of distribution company in Bolivia:*** LEI provided inputs into the valuation of a Bolivian distribution company, including developing the cost of capital; assessing demand, cost, and tariff forecasts; and reviewing the overall cash flow model. LEI also reviewed the company's historical performance relative to efficiency and performance targets

- ***developed price trends, in conjunction with the valuation of several Colombian power plants:*** LEI also provided an evaluation of the Colombian market, an overview of modeling methodologies and assumptions, and modeling results. The modeling results included forecast spot market prices, plant dispatch and revenues (energy and capacity), under a variety of scenarios

- ***conducted tariff review for Ente Nacional Regulador de la Electricidad ("ENRE"):*** the Argentine regulatory authority for the electricity sector (ENRE) awarded a contract for a tariff review of Edenor, a large utility serving the northern portion of Buenos Aires to a consortium led by LEI. The engagement entailed evaluating the performance of Edenor in the 1992-2002 tariff period; advising ENRE on international best-practice design of distribution tariffs; proposing a tariff setting methodology for the 2002-2007 tariff period; providing technical assistance in the analysis of information presented to ENRE by Edenor; proposing tariffs for the 2002-2007 tariff period; and assisting ENRE during public hearings on the proposed tariffs. The consortium proposed that tariffs be set via an RPI-X approach employing Data Envelopment Analysis (DEA) for establishment of the X-factor

Europe

- ***European power market analysis:*** LEI worked with one of North America's largest independent operator of power generation facilities to develop a comprehensive analysis of central European power markets including price forecasts and renewable energy policies. As part of its client's efforts to acquire a portfolio of hydroelectric power generating facilities, LEI's team developed a medium-term price forecast, stress tested critical assumptions, and provided detailed insight into federal and state renewable energy policies

- ***power price forecast for Balkans:*** to support potential bid to acquire nuclear station in Bulgaria, led team forecasting revenues from future spot power market sales. Issues included treatment of carbon emission credits, extent of regional integration, and availability of existing transmission capacity

Business Development and Strategy

North America

- ***advised on energy transition accelerator:*** LEI was engaged by a nonprofit organization to support in designing a jurisdictional-scale carbon crediting standard to encourage emission reductions in eligible developing countries. The project involved setting out methodologies and procedures addressing issues including crediting baselines, additionality, and monitoring and verification rules, as well as host jurisdiction eligibility criteria with respect to governance and safeguards. Specifically, LEI performed a scenario analysis that evaluated several alternative crediting approaches for three test developing countries, and provided an analysis of the results, including assessing the implications of each approach and providing recommendations

- ***performed a peer-group analysis of Independent Power Producers ("IPPs") in the US market:*** LEI presented research to a client with insights on the key economic, financial and strategic factors contributing to growth of mid-sized companies in the US merchant generation market. LEI identified nine categories of IPPs in the US merchant market and defined a subset of companies to be considered as the peer-group of the client. For the peer-group, LEI reviewed key success criteria of each company including business focus, leadership, growth strategy and financial performance. LEI presented three peer-group companies as case studies to highlight examples of successful players in the US IPP market. Overall, LEI highlighted the implications that current market trends and key success factors of Osaka's peer-group would have on the company's future growth strategy in the US market.

- ***transmission review in Canada:*** LEI was hired by a French consulting firm to provide commentary insights on the state of the transmission and distribution market in a number of Canadian provinces including Alberta, Ontario, British Columbia, Manitoba, Saskatchewan and Quebec

- ***study on transmission and distribution:*** LEI collaborated with SratOrg, a French consultancy on the development of strategic recommendations for market penetration in the US transmission and distribution markets. As part of this work, LEI and StratOrg performed a detailed analysis of the US market structure, identifying key market players and recent development, as well as barriers of entry and market opportunities for a prospective European investor. LEI travelled to Paris for an internal workshop session with Stratorg and actively participated in the final presentation of the team findings before the client's top managers.

- ***exploring a state of the world where Quebec becomes a net importer:*** LEI was hired by a large utility to brainstorm over a State of the World where the historical energy flows between Quebec, and its neighboring markets (NY, NE and ON) are reversed; essentially a world in which Quebec becomes a net importer of energy. The brainstorming exercise focused on identifying the reasonable volume of energy QC could rely upon to satisfy its planning obligations, identify potential challenges (regulatory, planning, supply availability, etc..) associated with the reliance on such imports, and debate over a planning strategy adequate for such State of the World. The brainstorming session included LEI and the utility's senior trading team

- ***assessment of US natural gas storage business:*** for a large Japanese gas utility, examined trends in regulation and investment in the US natural gas storage business. Engagement included comparison of natural gas storage business risks to that of IPP investment

- ***distressed asset acquisition strategy:*** advised a major Japanese utility on entry strategies to the US market, including performing a workshop on due diligence, US regional market analysis, and asset valuation; arranging for introductions to major asset sellers, potential investment partners, and advisors; and creating a screening methodology and database of potential acquisition targets

- ***workshop on performance-based ratemaking strategy:*** for first stand-alone transmission company in North America, conducted day long workshop on issues associated with PBR, including the types of PBR and which one is most appropriate for what type of company, the sources of efficiency gains observed in other transmission companies worldwide, and the impact of performance standards on profitability and flexibility

- ***global generation investment strategy:*** for a major Canadian generation company, used modern portfolio theory to identify combination of asset classes and geographic locations which would result in optimal risk-reward combination for generator given its core competencies. Deliverables included interactive model to be used by generator staff on an ongoing basis

- ***development of regulatory and financing strategy for transco:*** for first stand-alone transmission company in North America, evaluated key transaction parameters, assessed allowed ROE, proposed strategy for attaining favorable incentive rates, and helped to identify potential cost savings

- ***review of business plans for hydrokinetics technology company:*** for start up hydrokinetics technology company, LEI reviewed business plans and applicability of technology worldwide. Tasks included commenting on strategic plan, advising board members on the evolution of renewable energy markets worldwide, and assessing US Federal Energy Regulatory Commission polices towards hydrokinetic projects

Africa, Asia and the Middle East

- ***conducted workshop on generation reliability standard review in Malaysia:*** LEI held a two-day workshop on Generation Reliability Standard Review Seminar for TNB in Kuala Lumpur, Malaysia. The topics included: Malaysia reliability standard policy overview, jurisdiction review on reliability indices and benchmarking Malaysia's reliability standard against other countries, inter-play between government agencies in formulating the reliability standard, lessons learned from other counties, incorporating renewable energy, interconnection and distributed generation in calculating reliability indices, input parameter to derive the value of reliability indices, and lesson learned from LOLE studies from other jurisdictions.

- ***advisory services on the development of a 75 MW hydroelectric power plant in Cameroon:*** under a USTDA contract, AJ Goulding acted as a Senior Energy Market Specialist in the LEI portion of the work for a consortium to provide financial and technical advisory assistance to the Ministry of Energy and Water Resources of the Government of Cameroon with respect to the development of a 75 MW hydroelectric power plant at Bini à Warak. Specific tasks included review of Cameroon's existing regulatory system, regional market demand analysis and assessment of developmental impact of the project

- ***business development opportunities in India:*** for UK electricity and mining conglomerate, provided detailed assessment of opportunities in construction of integrated mining and mine-mouth power stations and in distribution of electricity

Europe

- ***European renewables investment strategy:*** on behalf of a global power and real estate investment company, reviewed policies towards renewable energy in Europe and individual European companies, as well as available assets, sites, and investment climate

- ***unbundling of French state-owned vertically integrated monopoly:*** worked with leading French electricity generator and supplier to examine how to create independent profit and loss statement for its generation assets, benchmark performance against expectations, and separate revenues from plant operations from those gained through trading

- ***renewables value chain investment analysis:*** for Dutch foundation based in Switzerland, examined macro trends associated with renewable energy in several major global economies, including the global supply chain from component manufacturers to installation to operation. Objective was to determine where on the renewables value chain the most profitable opportunities could be found

- ***arguments for retaining vertical integration:*** for large French utility, reviewed cases worldwide in which during liberalization incumbents were allowed to remain active across the value chain, including retail. Our work included an assessment of the minimum competition enhancing measures regulators may require in order for the utility to continue operating in all or most of its traditional supply chain activities

Regulatory Economics

North America

- ***supported PBR filing:*** LEI assisted a large Alberta utility with its third generation performance-based ratemaking ("PBR") filing, including advising on incentives, effectiveness of inflation factors, potential for special capital expenditure provisions responsive to government electrification policies, productivity factors, length of regulatory period, and other matters associated with PBR

- ***Indiana energy study:*** LEI was retained by the Indiana Chamber of Commerce Foundation to provide an Indiana energy policy study and report covering the following topics: (1) an overview of Indiana's energy resources and electricity industry; (2) a discussion of the state's regulatory framework; (3) a summary of Indiana's national ranking in terms of costs, affordability and reliability; (4) an exploration of the factors that have driven cost changes; (5) goals for policy going forward; and (6) a discussion of what can be done through the legislative process to impact energy costs for consumers. LEI was also engaged to present the paper to stakeholders in Indianapolis. The paper will be used by ICF for informational purposes ahead of the state's legislative session.

- ***referent pricing of comparable technologies and due diligence support on PPA negotiation:*** LEI was hired by a large electric utility to provide due diligence support on their renegotiation of long term contracts. LEI's scope of work consisted of developing a benchmark of future energy prices (2040-2060) by modeling referent prices (LCOE) for a portfolio of technologies likely to be developed in the markets of interest. The benchmark exercise was supplemented by commentaries on the potential state of energy markets in a 20 to 40 year horizon (by exploring the potential changes and evolution in energy markets dynamics and overall construct), and the review of potentially disruptive promising technologies. Finally, LEI provided technical support to the utility's leadership throughout their decision making process ahead of the start of the negotiations

- ***supported Manitoba cost of service review:*** London Economics International LLC ("LEI") was retained by Christian Monnin Law Corporation, at the request of Manitoba Public Utilities Board, to represent the interests of small commercial customers in its review of Manitoba Hydro's cost of service review

- ***supported setting of Nova Scotia Performance Standards:*** LEI was engaged by the Nova Scotia Regulatory Authority – the Nova Scotia Utility and Regulatory Board (NS UARB) to assist in setting performance standards for NSPI in respect of reliability, response to adverse weather conditions, and customer service for Nova Scotia

- ***conducted NYC entities capacity portfolio analysis:*** For a large Canadian hydropower generator, LEI performed a review and analysis of the capacity portfolio of several entities operating within New York City

- ***Conducted 2015 Review of Non-Energy Margin***: London Economics International LLC ("LEI") was asked by ENMAX Energy Corporation ("EEC") to review EEC's proposed non-energy return/risk margin associated with expenses incurred as a result of operation of the Regulated Rate Option ("RRO"). For the client, LEI reviewed the settled practice in Alberta, recent proposed changes providing for an all-inclusive return margin, and calculated an indicative range of margin for EEC.

- ***conducted analysis of Nova Scotia electricity systems:*** LEI was retained by Nova Scotia Department of Energy ("NS DOE") to perform analysis of the organization and governance of electricity systems both cross-jurisdictionally and within the province of Nova Scotia. The scope of work was divided into two main phases: (i) Review of international best practices and lessons learned; and (ii) Translation of best practices and lessons learned into best fit for NS

- ***assessed consistency of proposed Clean Energy Standard with existing Alberta electricity market design characteristics:*** Paper included discussion of potential additional program attributes, indicative cost assessment, impact on investment and reliability, and assessment of further required research

- ***assisted generator in hydro development strategy:*** assisted Alberta generator on strategy related to new large scale hydro development, including justification as inflation hedge for potential pension fund investors, integration into competitive market while maintaining ability to finance, and other strategic and regulatory support

- ***developed a transmission cost causation study for the Alberta Electric System Operator ("AESO"):*** the study will be used for the determination of the AESO's Demand Transmission Service Rate DTS, and is expected to be filed with AESO's 2014 tariff application to the Alberta Utilities Commission ("AUC"). The study is intended to cover four main topics: (i) Functionalization of Capital Costs; (ii) Functionalization of Operating & Maintenance ("O&M") costs; (iii) Classification of Bulk and Regional System Costs; and (iv) Implementation Considerations

- ***conducted review of gas transmission sector in the US:*** for a European economic advisory firm, LEI reviewed the US gas transmission sector focusing on its regulatory structure. Tasks included researching the regulatory approach, legal framework, allowed capital costs and incentive mechanisms of the US gas industry

- ***provided a briefing for Alberta's Minister of Energy:*** briefings consisted of two 90 minute presentations – the first was a review of the Alberta Retail Market, and the second was a wholesale market review of ERCOT, Australia, Singapore, UK and Ontario

- ***supported client's transmission FBR reopener application:*** in particular, the client wanted LEI to provide an independent opinion on their argument (i) to amend the G factor calculation to eliminate the G-factor lag effective January 1, 2011 and (ii) to reduce EPC's current X factor of 1.2% to 0.0%. LEI provided support throughout the whole litigation proceeding by responding to information requests which involved additional research and analysis, including synthesis of publications on recent technological advances in electricity transmission sector, and updating the Ontario LDCs TFP model to ten years

- ***reviewed the US gas transmission sector focusing on its regulatory structure:*** on behalf of a European economic advisory firm, an LEI team, led by AJ, reviewed the US gas transmission sector. Tasks included researching the regulatory approach, legal framework, allowed capital costs, and incentive mechanisms of the US gas transmission industry. Analysis focused on US Federal Energy Regulatory Commission ("FERC") regulatory proceedings, as well as state commission findings, related to allowed returns, capital investment requirements, and treatment of capacity

- ***review of stranded cost settlement and default supply pricing:*** prepared support for regulatory filing in Pennsylvania assessing benefits to customers from a proposal to extend recovery period for competitive transition charge while extending fixing price for default supply

- ***assessment of changes in market power for a FERC Section 203 filing:*** in connection with a proposed combination of generation portfolios, developed testimony concerning the change in market concentration as a result of the transaction, including an assessment of changes in HHIs under various market definitions

- ***review of durability of gas franchises in the face of competition:*** reviewed state regulator decisions and FERC rulings regarding sanctity of natural gas distribution franchises, assessed relevance in the face of deregulation of gas markets

- ***market response to tax credit:*** performed in-depth analysis of impact of Section 29 tax credit for non-conventional fuels production on supply and price response in US southwestern gas markets

- ***economic efficiency effects of retail market design:*** for major US electricity retailer, analyzed various forms of retail electricity competition and default service parameters and compared them to retail/wholesale structure in other industries to determine welfare effects

- ***design of incentive rate structure for Alberta utility:*** for a large metropolitan Alberta utility, AJ advised on design of a proposed incentive based rate structure, including a multi-year term, operating cost incentive structure, and earnings sharing mechanism. Deliverables aided in development of regulatory filings and included testimony before the Alberta Utilities Board

- ***critiquing and improving electricity market structure in Alberta:*** for market institutions and regulators in the Canadian province of Alberta, performed extensive analysis of current industry market structure, including role of Power Pool, Transmission Administrator, Market Surveillance Administrator, the Scheduling Coordinator, and the Balancing Pool. Directed detailed analysis of market power issues associated with divestiture of specific assets and advised on particular market rules to ameliorate strategic behavior

- ***recommendations regarding market power mitigation and retail market design:*** in two separate engagements, advised the Government of Alberta on alternatives for rate designs for small customers and on measures to monitor, measure, and ameliorate market power; both engagements included extensive modeling of Alberta wholesale market and of retail supply tariffs

- ***evaluation of rates across Canada:*** reviewed rates charged to final consumers across Canada and identified distortions in rate design across provinces; performed modeling to adjust for distortions; developed appropriate calculations to appropriately compare rates across jurisdictions

- ***resource adequacy mechanisms for Alberta:*** worked with generators association to assess alternative approaches to assuring resource adequacy. Reviewed mechanisms for capacity and default supply procurement worldwide, developed alternatives for Alberta, and engaged in intensive stakeholder consultation

- ***strategic implications of US deregulation:*** performed in-depth study of the impact of unbundling in the US on the fundamental economics of the electric power industry at all points on the value chain; identified regional investment opportunities congruent with these dynamics

- ***ROE expert evidence:*** London Economics International LLC ("LEI") was retained by the legal counsel for the Prince Edward Island Regulatory and Appeal's Commission ("IRAC") to provide independent expert evidence on a just and reasonable return on equity ("ROE") for the Maritime Electric Company, Limited ("MECL"), associated with their General Rate Application ("GRA") for 2023-2025

- ***led Alberta performance review:*** LEI was engaged to perform an assessment of the Alberta Energy Framework, which encompasses the wholesale generation market, retail market, agencies, transmission planning, access and distribution, as well as the operations of the Alberta Interconnected Electricity System. The analysis included both qualitative and quantitative components

- ***led Ontario gas LDC performance-based ratemaking project:*** LEI was engaged by Union Gas to review Union's proposed 2014 to 2018 incentive ratemaking ("IR") plan as presented to stakeholders on April 29th, 2013 and to examine case studies of approaches to IR applied to other North American gas distribution utilities. In the case study analysis, Union particularly requested LEI to examine approaches to a set list of ratemaking parameters: productivity and X-factor trends, alternative approaches to designing an I-X framework, approaches to establishing inflation factors, approaches in other jurisdictions to applying an Earnings Sharing Mechanism ("ESM"), use of capital trackers for unknown costs, appropriateness of deferral accounts for unaccounted-for gas ("UFG"), and service quality indicators ("SQIs") and how they are measured. LEI was subsequently requested by Union to provide comments on Union's draft Settlement Agreement

- ***review of RRO in Alberta:*** London Economics International LLC ("LEI") was asked by ENMAX Energy Corporation ("EEC") to review EEC's request for continuation of the practice of earning a fixed margin associated with expenses incurred as a result of operation of the Regulated Rate Option ("RRO"). For the client, LEI reviewed the settled practice in Alberta, investigated the risk of operating the RRO, and calculated an indicative range of margin for EEC

Asia and the Middle East

- ***deep dive of regulation market design:*** Following completion of the above-mentioned engagement for a Middle Eastern greenfield smart city, Frontier Economics and LEI were retained by the same large Middle Eastern entity in 2022 to perform a deep-dive analysis and advise on the "Regulation" workstream. The ongoing project envisions two work packages: (i) WP 1: Regulation and rules. Under this work package, the project team is detailing the market operation principles and the required regulations across each value chain activity, which will facilitate and operationalize the market design concept selected by the client; and (ii) WP 2: Contrast of desirable regulation and rules with current law. Under this workstream, the project team shall provide the client with a detailed contrast of existing country-level laws/regulations with the city's laws/regulations. The team will also perform a gap analysis associated with ideal rules and regulations needed to achieve the city's objectives. In addition, the team will provide an implementation roadmap, including preparation needed for activation. In addition to these work packages, the team will provide adhoc assistance to the client, as well as present a series of workshops consistent with each area of regulation, to discuss preliminary findings, recommendations, and to incorporate feedback from the client

- ***conducted IBR workshop in Malaysia:*** LEI was retained by the largest electric utility company in Malaysia to conduct a workshop on incentive-based ratemaking ("IBR"). The topics for the workshop include theoretical conceptual overview of IBR regulatory framework, key elements of comprehensive IBR regimes, best practices of IBR in various jurisdictions, timing and framework in other jurisdictions, how to convince regulators and stakeholders, identifying barriers to successful implementation of the IBR, and moving from first to second generation IBR, to name a few.

- ***review of rate of permitted return in Hong Kong:*** for the Hong Kong Government, LEI reviewed the rate base and the rate of permitted return for the power companies in Hong Kong under the Scheme of Control Agreements. This required reviewing the alternatives to using Average Net Fixed Assets as the rate base, examining the assumptions used and methodology to calculate the WACC of power companies, updating the indicative range for the permitted rate of return, and recommending changes to existing rates of return by identifying new international best practices

- ***developed financial, commercial, and regulatory framework, in addition to drafting an investment strategy and model for Saudi clean energy institution:*** deliverables included: (i) A master plan on how to develop renewable and atomic energies based on local value chains in Saudi Arabia; (ii) An economic framework to create a favorable environment in order to follow this master plan; (iii) An investment strategy to make use of KSA resources and available funds in an efficient way; (iv) A multitude of international case studies to avoid costly mistakes in the future and to know when to adopt; (v) A final report on 'National Policy for Investment in Alternative Energy Sources'; and (vi) Two 'sales pitch' documents for submittal to the King's Supreme Council and for the financial community

- ***advised Jordan regulator:*** advised the regulator on the weighted average cost of capital and optimal capital structure for Jordan's three distribution companies: EDCO, IDECO and JEPCO. The recommended optimal capital structure was consistent with targeted debt service and interest coverage ratios in line with the rating methodology for distribution companies from the global credit rating agencies. Work also included identifying salient risk factors for the distribution companies, identifying appropriate local and international metrics and benchmarks, developing a usable cost of capital model, and providing training workshops for local staff

- ***drafting National Renewable Energy Plan for Saudi Arabia:*** on behalf of the regulator, developed proposal for renewable energy plan for Saudi Arabia, including assessment of procurement methods, new institutions required, and determination of resource eligibility

- ***rate design for water and wastewater services in Saudi Arabia:*** on behalf of utility serving industrial areas in the Kingdom, examined appropriate regulatory structure and recommended approach to establishing new regulatory body, including composition of regulator, incentive structure, and tariff modeling

- ***design of wheeling tariff and pilot program for Saudi Arabia:*** for Saudi regulator, developed proposed plan for wheeling of power in Saudi Arabia, including proposed pilot program, assessment of impact on incumbent, relative economics of wheeling versus the industrial tariff, and review of associated commercial and regulatory issues

- ***tariff design for Kingdom of Saudi Arabia:*** led engagement with international team assessing tariff design, modeling, and electricity market evolution in Saudi Arabia; engagement resulted in a revised tariff system, including performance based rates, tolling agreements for generation, and an open access tariff. Included holding workshops for regulator in explaining cost of capital, tariff design, and other regulatory issues

- ***Electricity Industry Restructuring Plan for Saudi Arabia:*** AJ developed the blueprint for industry restructuring in Saudi Arabia, including unbundling of the current monopoly vertically integrated utility, introduction of wholesale competition, and creation of a Single Buyer

- ***developed regulatory incentives in Jordan:*** examined regulatory framework in Jordan, with particular focus on creating specific regulatory incentives for distribution companies to optimize their operational expenses. Proposals envision move away from cost of service regime to incentive based structure benefiting customers and shareholders

- ***assessed retail margin review for generator in India:*** reviewed retail margins on electricity sales worldwide, in order to provide Indian generator insight with regards to appropriate retail margins that could be charged to selected customers in one Indian jurisdiction. Engagement involved review of case studies of electricity retail margins around the world, including the US, UK, and Australia. In addition, retail margins in other industries were reviewed, along with the progression of margins as an industry progresses from infancy to maturity

- ***institutional development for IPP promotion:*** contributed to Indian private power promotion efforts through technical assistance program to state electricity boards, central government agencies, and private firms, with particular emphasis on role of PURPA in creating US IPP industry

- ***bagasse cogeneration:*** worked extensively with Indian sugar mills, equipment suppliers, government investment promotion agencies, and state electricity boards to develop cost-effective targeted loan and technical assistance program to promote bagasse cogeneration

- ***barriers to introduction of new coal combustion technologies in emerging markets:*** served as liaison between India's National Thermal Power Corporation (NTPC) and US research institutions to assess ways to adapt US coal combustion technologies to Indian conditions

- ***recommendations for next Scheme of Control in Hong Kong:*** worked with the Hong Kong government to develop a series of recommendations regarding appropriate allowed returns, calculation of asset base, prevention of over-investment, and rate stability

- ***lessons from North American experience for Chinese regulators and grid companies:*** for a set of Chinese state-owned companies, including grid operators, the nuclear operating company, and provincial power companies, London Economics International LLC prepared a series of detailed briefings on developments in electricity market design worldwide, with a particular emphasis on lessons from the North American experience. This experience was then used to highlight the various alternatives for market design in China, and the potential outcomes

- ***implications of restructuring the Japanese power sector:*** for a major Japanese development bank, we analyzed the impact of proposed reforms on a Japanese transmission and generation company, including the potential for stranded costs, opportunities for expansion of transmission, and future tariff setting regimes. The engagement included extensive training of the development bank's staff, as well as the creation of a working model of the Japanese power sector

- ***Economic Study - Madrid Protocol:*** London Economics International LLC ("LEI") was engaged as a subcontractor by a Middle Eastern client to conduct an economic study assessing the costs and benefits of Saudi Arabia potentially joining the Madrid Protocol. The study involved: quantifying the expected benefit to KSA trademark holders in registering their trademarks internationally; assessing the financial impact on KSA trademark agents; estimating the operating cost of implementing the protocol; reviewing the pros and cons of joining the protocol; and assessing the impact on key macroeconomic drivers in the Kingdom

- ***Hong Kong ROE study:*** in the context of investment incentives required to achieve Hong Kong government's net zero target, a vertically integrated Asian utility retained Frontier/LEI to conduct a study that scans the regulatory landscape and regulatory returns (both allowed and achieved) by a relevant sample of utilities around the world. A key objective is to understand factors that contribute to differences between: (i) the level of ex ante allowed returns set by the regulators; and (ii) the level of actual ex post returns earned by utilities. In this assessment, the impact of inflation needs to be considered separately; and the study needs to focus on level of over/under performance as well as types of regulatory instruments that lead to such over/under performance. The analysis is expected to draw relevant lessons for the client in the context of the setting of the Permitted Returns in Hong Kong

- ***Abu Dhabi Department of Energy review:*** London Economics International LLC ("LEI"), in partnership with Frontier Economics, was retained by the Department of Energy ("DoE") in Abu Dhabi to work through Deloitte to advise the DoE in Abu Dhabi on: (i) Phase 1: the definition of non-for-profit for Emirates Water and Electricity Company ("EWEC"), the single-buyer and system operator; and (ii) Phase 2: a suitable framework for economic regulation of EWEC

Central and South America

- ***overview of Colombia market and revenue forecasts for target assets:*** LEI was hired by an electric operator for the purposes of valuing a portfolio of generating assets in Colombia. LEI's scope of work consists of a comprehensive review of the Colombia energy market (including fuel and power market drivers), describe in details the functioning of both wholesale power market and firm energy market (capacity market), develop forecasts of spot prices in order to derive expected revenues for the portfolio. Colombia being a hydro dominated system, as part of its modeling exercise, LEI ran a Monte Carlo simulation to develop a series of probabilities associated with generation profiles of Colombia's hydro resources to reflect the impact of weather conditions and water inflows on hydropower plants' output. LEI summarized its research and modeling results in a final report that was presented to lenders and other interested parties

- ***implications of performance based ratemaking (PBR) in the Caribbean:*** for a privately owned integrated electric company based on a well developed Caribbean island, directed strategic analysis of implications of PBR, suggested approach to regulators, and provided indicative benchmarking analysis

- ***Regulatory review of power markets for Chilean client:*** at the request of a major Chilean generating company, LEI performed a detailed review of the regulatory regimes of four restructured power markets (California, Colombia, Nord Pool, and Spain), as well as an analysis of the current Chilean regulatory regime and the changes to that regime that the regulator has proposed. The review addressed the positions of all stakeholders, with a particular focus on the implications of various types of market design on generators

Europe

- ***served as Ukraine Electricity Tariff Expert:*** As part of a team hired by the Anti-Crisis Energy Group of the Cabinet of Ministers of Ukraine, LEI was tasked with identifying opportunities to streamline and enhance procedures used to set tariffs and prices for electricity produced. LEI performed an extensive literature review of the Ukrainian electricity market, assessed the current tariff-setting regulations and procedures and carried out in-person interviews with stakeholders. LEI wrote a briefing memo on the Ukrainian market and a recommendations paper in line with its scope of work. The recommendations were incorporated into an Energy Resiliency Plan that would aid decision-making to the Cabinet of Ministers and the Verkhovna Rada

- ***global regulatory review:*** assisted private equity player in assessing electricity markets in Eastern Europe, Turkey, Asia, and Latin America to determine potential regulatory and market issues associated with proposed purchase of diverse portfolio of generation, distribution, natural gas pipeline, and retail fuels businesses

- ***preparing appropriate framework for private investment in Romanian distribution sector:*** on behalf of a private client, worked with Romanian regulators to develop a consensus on approaches to capital recovery, PBR application, performance standards, supply cost-pass through, and cost of capital. These elements served as preconditions for the private investor's participation in the privatization process

Written and oral expert testimony outside of Ontario

Note: expert testimony was also a component of some projects listed above, particularly regulatory projects for Ontario Power Authority, Ontario Energy Board, and involving incentive rates in Alberta.

- ***expert testimony on refiled Grid Plan:*** LEI provide the following services to Constellation Energy: (i) an assessment of proposals made by ComEd and other parties in the Case; (ii) preparation of data requests on behalf of Constellation and assessment of other parties' data requests and responses provided during the Case; (iii) preparation of multiple rounds of written expert testimony, as necessary, for filing in the Case; (iv) participation in the evidentiary hearing for the Case, including appearing for live testimony/cross-examination, as necessary; (v) consulting with Law Firm and Client regarding analysis and strategy relating to the Case; (vi) providing such other services related to its role as an expert witness in the Case as may be requested by the Law Firm

- ***avoided costs expert in South Carolina:*** LEI was engaged by the Public Service Commission of South Carolina ("SC PSC") to serve as a qualified, independent third-party consultant in three avoided cost proceedings (Docket No. 2021-88-E, Dominion Energy South Carolina; Docket No. 2021-89-E, Duke Energy Carolinas; Docket No. 2021-90-E, Duke Energy Progress). LEI first evaluated the avoided cost rates, methodologies, terms, calculations, and conditions outlined in each of the applications, and then filed expert reports outlining LEI's opinion of each utility's calculation of avoided costs based on evidence in the record. The LEI team was also available to respond to discovery, be deposed, cross-examined, and to testify before the SC PSC as requested

- ***avoided costs expert in South Carolina:*** LEI was engaged by the Public Service Commission of South Carolina ("SC PSC") for a second time to serve as a qualified, independent third-party consultant in the state's 2023 avoided cost proceedings (Docket No. 2023-15-E, Dominion Energy South Carolina; Docket No. 2023-16-E, Duke Energy Carolinas; Docket No. 2023-17-E, Duke Energy Progress). LEI had previously served a similar role in the 2021 avoided cost proceedings. As part of the 2023 engagement, LEI evaluated the avoided cost rates, methodologies, terms, calculations, and conditions outlined in each of the utility's applications, and then filed expert reports outlining LEI's opinion of each utility's calculation of avoided costs based on evidence in the record. The LEI team also responded to discovery and testified before the SC PSC.

- ***review of valuation metrics used in conjunction with tax payment challenge for an Alberta generator:*** assessed the appropriateness of valuations utilized to determine depreciation deductions related to the acquisition of a coal-fired generating station. Engagement also required creating forecasts that would have been appropriate at the time the acquisition was made several years previously, as well as calculating asset values using multiple valuation approaches. Multiple forecasting tools were used. Engagement included developing critiques of work by opposing expert witnesses

- ***examination of Swiss electricity market:*** for a US financial institution, AJ reviewed the development of the Swiss electricity market and specifically the position of hydro stations within that market. Analysis included a discussion of the factors that influence the value of hydro stations, presence of foreign owners in the Swiss electricity market, and use of post-tax cash flow to evaluate potential investments

- ***analysis of potential customer impacts due to holding company acquisition of merchant generator:*** discussed ways in which customer rates would be impacted by potential credit rating downgrades of regulated subsidiaries due to holding company parent's acquisition of merchant generator; engagement included examination of impact on default supply as well as reliability

- ***assessment and valuation of quantum meruit claims:*** for advisor and developer of biomass facilities, provided expert opinion on value of services provided based on industry knowledge, review of correspondence, and experience providing or commissioning similar services

- ***review of Dutch electricity market regulatory dynamics:*** in a case before the US Federal Court of Claims related to economic substance, provided understanding of how Dutch electricity market was structured in the mid-1990s, how it was expected to evolve, and how it did actually evolve. Issues addressed included market structure, regulation, role of non-utility investors, and role of private and international investors

- ***valuation of PPAs associated with IPPs in Thailand:*** as an expert witness in an arbitration case, AJ quantified the change in value resulting from modifications to several PPAs associated with a power project in Thailand. Engagement included review of PPAs, evaluation of Thai power sector restructuring process, extensive modeling of financial aspects of PPAs, and assessment of financing alternatives; client won on all claims

PUBLICATIONS:

Goulding, AJ. "Mind the Gap: The Impact of Budget Constraints on Ontario's Net Zero Plans." C.D. Howe Institute. May 2024.

Goulding, AJ. "Potential implications of the COVID-19 crisis on long-term electricity demand in the United States." Center on Global Energy Policy at Columbia University. October 2020.

Goulding, AJ and Jarome Leslie. "Dammed If You Do: How Sunk Costs Are Dragging Canadian Electricity Ratepayers Underwater." C.D. Howe Institute. January 2019.

Goulding, AJ and Stella Jhang. "Secretary Perry's Grid Resiliency Pricing Rule: On Market Interventions and Minimizing the Damage." Columbia University. SIPA – Center on Global Energy Policy. October 2017.

Goulding, AJ. "Railroads, Utilities and Free Parking: What the Evolution of Transport Monopolies Tells Us About the Power Network of the Future." Columbia University. SIPA – Center on Global Energy Policy. November 2016.

Goulding, AJ "A New Blueprint for Ontario's Electricity Market." C.D. Howe Institute. Commentary No. 389. September 2013.

Goulding, AJ and Serkan Bahçeci. "Stand-by rate design: Current issues and possible innovations." *Electricity Journal*, June 2007, pp 87 – 96.

Goulding, AJ and Bridgett Neely. "Picture of a Stalled Competitive Model" *Public Utilities Fortnightly*, February 2005, pp 35 - 42.

Goulding, AJ and Bridgett Neely. "Acceding to Succeed" *Public Utilities Fortnightly*, July 2004.

Goulding, AJ "Let's Get This Party Started: Why Ontario needs a competitive market" *Public Utilities Fortnightly*, May 2004, pp 16 - 20.

Goulding, AJ and Nazli Z. Uludere. "Uncovering the *true value* in merchant generation" *Electricity Journal*, May 2004, pp 49-58.

Goulding, AJ "On the Brink: Avoiding a Canadian California" *Public Utilities Fortnightly*, February 5, 2003.

Goulding, AJ, Julia Frayer, Jeffrey Waller. "X Marks the Spot: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly,* July 15, 2001.

Goulding, AJ, Julia Frayer, Nazli Z. Uludere. "Dancing with Goliath: Prospects After the Breakup of Ontario Hydro" *Public Utilities Fortnightly*, March 1, 2001.

Goulding, AJ, Carlos Rufin, and Greg Swinand. "Role of Vibrant Retail Electricity Markets in Assuring that Wholesale Power Markets Operate Effectively." *Electricity Journal*, December 1999.

Adamson, Seabron and AJ Goulding. "The ABCs of Market Power Mitigation: Use of Auctioned Biddable Contracts to Enhance Competition in Generation Markets." *Electricity Journal*, March 1999.

Goulding, AJ "Retreating from the Commanding Heights: Privatization in an Indian Context." Columbia University: *Journal of International Affairs*, Winter 1997, pp. 581-612.

Hass, Mark R. and AJ Goulding. "Impact of Section 29 Tax Credits on Unconventional Gas Development and Gas Markets." Society of Petroleum Engineers: SPE 24889, presented at 67th Annual Technical Conference, Washington, DC, October 6, 1992.

SPEAKING ENGAGEMENTS:

"One Year On: a Transatlantic Perspective for Clean Energy Investments" Panelist, Frontier Economics live webinar. February 28th, 2024

"Resilience in the Electricity Sector." Speaker, City of Toronto, Ontario, Canada. Seminar. February 9th, 2024.

"Innovations in Wholesale Market Design and Governance." Panelist, Ivey's 7th Annual Electricity Workshop. October 16th, 2023.

"Ensuring Affordability." Panelist, Electricity Canada's Regulatory Forum 2023. May 10, 2023.

"Is There a Future for Mega Energy Projects?" Panelist, Ivey's 4th Annual Workshop on the Economics of Electricity Policy and Markets. October 6, 2020.

"COVID-19 related demand destruction and its implications for utilities and IPPs." Speaker, Bank of America's 2020 Future of Power conference. September 23, 2020.

"Fortune-Telling and Fortune-Seeking: The Future of the Power Markets in New England." Panelist, Northeast Energy and Commerce Association ("NECA") Wholesale Panel discussion. Webinar. May 20, 2020.

"Examining Risk & Opportunities In Canada's Procurement Models." Panelist, Gowling WLG's live webinar. May 23, 2019.

"*System and Tariffs Impacts of Increasing distributed generation."* Speaker, CAMPUT. Calgary, Alberta, Canada. May 7th, 2019.

"Rate design and fixed cost recovery revisited." Panelist, Ivey Energy Policy and Management Centre ("EPMC"). Toronto, Ontario, Canada. October 22nd, 2019.

"Alternative Regulatory Approaches." Speaker, Electricity Distributors Association Energy Business Innovation Conference. Toronto, Ontario, Canada. October 22nd, 2019.

"Regulation" – Keeping up with the pace of change." Panelist, APPrO. Toronto, Ontario, Canada. November 12th, 2018.

"Blockchain and the Grid." Panelist, Wires Conference. Washington, DC, USA. October 25th, 2018.

"Considerations for policymakers regarding capacity mechanism design." Speaker, Independent Power Producers Society of Alberta ("IPPSA"). Calgary, Alberta, Canada. July 17th, 2017.

"Future Models for Utility Ownership and Regulation in Hawaii." Speaker, VERGE Hawaii: Asia Pacific Clean Energy Summit. Hilton Hawaiian Village, Honolulu, Hawaii, US. June 20th, 2017.

"Capacity Market Review: Workshop #2." Speaker, Independent Power Producers Society of Alberta ("IPPSA"). Calgary, Alberta, Canada. June 14th, 2017.

"Capacity Market Review: Workshop #1." Speaker, Independent Power Producers Society of Alberta ("IPPSA"). Calgary, Alberta, Canada. May 18th, 2017.

"Distributed Energy Resources: Regulatory Framework and Ratemaking Considerations." Speaker, CAMPUT Annual Conference 2017's CEA's Regulatory Innovation Task Group. Vancouver, British Columbia, Canada. May 10th, 2017.

"From Theory to Practice: Disruptive Technologies, Innovation and the Future of the Utility." Panelist, Northwind Professional Institute 13th Annual Electricity Invitational Forum, Langdon Hall, Cambridge, Ontario, Canada. January 27th, 2017.

"Ontario's Electricity Sector: Does the Current Institutional Framework Serve the Public Interest? Is it Times for Ontario to Consider a Fundamental Redesign?" Discussion Leader, Northwind Professional Institute 11th Annual Electricity Invitational Forum, Langdon Hall, Cambridge, Ontario, Canada. January 30th, 2015.

"What's Next for Ontario's Electricity Market?" Panelist, C.D. Howe Institute Roundtable, Toronto, Ontario, Canada. September 16th, 2014.

"Prices and Costs, Why Rates Don't Tell the Whole Story" Speaker, Making Markets Work Symposium – Manning Centre, Calgary, Alberta, Canada. June 25th, 2014.

"Examining the Future Structure of Ontario's Electricity Market: Should Ontario Incorporate a Capacity Market or Alternative Structural Framework?" Panelist, Ontario Power Conference, Toronto, Ontario, Canada. April 15th, 2014.

"Electricity Prices – Economics, Public Policy, Technologies and Affordability" Panelist, CCRE Energy Leaders Roundtable, Hockley Valley Resort, Orangeville, Ontario, Canada. March 27th, 2014.

"Priorities for enhancing Ontario's electricity market: What direction forward?" Panelist, APPrO, Toronto, Ontario, Canada. November 20th, 2013.

"Evolving Regulation in Ontario: Best Practices from Other Jurisdictions" Panelist, Ontario Energy Association's ENERGYCONFERENCE13, Toronto, Ontario, Canada. September 11th, 2013.

"Points to consider when valuing hydro in the US" Speaker, HydroVision 2013, Denver, Colorado, US. July 26th, 2013.

"Pricing Power in Ontario: Perspectives and Competitive Analysis on the Future Direction of Ontario Electricity Rates" Panelist, Ontario Power, Toronto, Ontario, Canada. April 17th, 2013.

"Why Alberta* is *Still Standing" Panelist, Independent Power Producers Society of Alberta's 19th Annual Conference – Last Market Standing?, Alberta, Canada. March 11th, 2013.

"Market Evolution in the context of the EMF and the post-election environment" Panel Moderator, Association of Power Producers of Ontario, Toronto, Ontario, Canada. November 16th, 2011.

"Green Energy Economics" Panelist, Electricity Distributors Association's ENERCOM, Toronto, Ontario, Canada. March 30th, 2011.

"Projected Supply-Demand Balance in Ontario: A Call to Inaction" Speaker, APPrO, Toronto, Ontario, Canada. November 18th, 2010.

"Changes in electricity policy: what will it cost?" Speaker, 2010 Ontario Energy Association Annual Conference, Niagara Falls, Ontario, Canada. September 21st, 2010.

"Energy Infrastructure Spending" Debate Panelist, Canadian Association of Members of Public Utility Tribunals (CAMPUT), Montreal, Ontario, Canada. May 5th, 2010.

"Strategic implications of the Ontario Green Energy Act" Presentation to Ontario Energy Association Green Energy and Conservation Joint Sector Committee, Toronto, Ontario, Canada. June 24th, 2009.

"Strategic implications of evolution of North American utilities sector in response to environmental initiatives" Presentation to Mitsui Canada Leadership Forum, Toronto, Ontario, Canada. June 17th, 2009.

"Making retail competition work in electricity" Speaker, Illinois Commerce Commission Retail Competition Workshop, Chicago, Illinois, US. October 2nd, 2006.

"Gods and monsters: the role of the Ontario Power Authority in Ontario's hybrid market" Speaker, Ontario Energy Association annual conference, Niagara Falls, Ontario, Canada. September 14th, 2005.

"Transmission investment in today's power markets: key considerations" Presentation to the Wyoming Infrastructure Authority, Casper, Wyoming, US. May 26th, 2005.

"The true cost of power: comparing rates for power across Canada" Speaker, Independent Power Producers Society of Alberta conference, Banff, Alberta, Canada. March 15th, 2005.

"Key considerations with regards to resource adequacy mechanisms in Alberta." Speaker, Independent Power Producers Society of Alberta luncheon, Calgary, Alberta, Canada. November 3rd, 2004.

"Finding the silver lining: investment opportunities in Canadian power markets" Speaker, 2004 Canada Power Conference, Toronto, Ontario, Canada. September 30th, 2004.

"Adding value for the shareholder: Managing small utilities in a period of regulatory change." Speaker, Ontario Electricity Distributors Association, London, Ontario, Canada. June 8th, 2004.

"Case studies in electricity market design: learning from experience." Guest lecturer, Columbia University Center for Energy and Marine Policy graduate program, International Energy Systems and Business Structures class, New York, New York, US. April 8th, 2003.

"'The grass is always greener' vs. 'All of your eggs in one basket': investment outlook for California and foreign markets." Speaker, Platt's Global Power Markets Conference, New Orleans, Louisiana, US. March 31st, 2003.

"Transmission congestion, valuation, and investment issues in the region surrounding Ontario." Speaker, Canadian Institute conference on Inter-jurisdictional Power Transactions, Toronto, Ontario, Canada. April 8th, 2002.

"Update on new generation development in Alberta." Speaker, Canadian Institute Conference on Managing Electricity Price Volatility in Alberta, Calgary, Alberta, Canada. February 27th, 2002.

'The Alberta market structure and implications of structural change." Speaker, Insight Conferences Alberta Power Summit, Calgary, Alberta, Canada. February 22nd, 2002.

"Implications for developers of key aspects of competing Midwest ISO designs." Speaker, INFOCAST conference on Maximizing the Value of QFs and IPPs, Orlando, Florida, US. February 1st, 2001.

"Risk and rewards from PBR for US utilities: lessons from overseas." Speaker, UTECH 2000 conference, St. Petersburg, Florida, US. November 30th, 2000.

"Dancing with Goliath: increasing competition in Ontario wholesale generation market." Speaker, Canadian Independent Power conference, Toronto, Ontario, Canada. November 27th, 2000.

"Asset valuation in evolving global power markets." Speaker and case study facilitator, World Bank conference on Emerging Issues in the Power Sector, Washington, DC, US. April 19th-21st, 2000.

"***Overseas exposure: is it worth the risk?***" Speaker at Global Power Markets Conference, organized by Global Power Report and McGraw-Hill, New Orleans, Louisiana, US. April 16th -19th , 2000.

"***Profiting from retail: challenges for MEUs.***" Speaker at conference on buying and selling electric utilities in Canada, organized by IBC USA conferences, Toronto, Ontario, Canada. November 15th-17th, 1999.

"***Assessing the US electricity market and evaluating US targets***." Facilitator for workshop on US acquisition opportunities for European energy firms, organized by IIR Limited, London, England. February 9th-11th, 1999.

Curriculum Vitae

Amit Pinjani

Director, London Economics International LLC

LONDON ECONOMICS

KEY QUALIFICATIONS:

Amit Pinjani has extensive experience advising North American and international clients on matters related to electricity regulation, market design, and cost of capital matters. Amit has been qualified as an expert economist by multiple regulatory authorities in North America, where he has submitted expert written and oral testimony. In addition to working on several economic and regulatory advisory projects, Amit has successfully managed energy litigation support and asset valuation projects with LEI.

Internationally, Amit has managed extensive engagements with government entities and private clients in the Middle East and Asia. Amit is a seasoned project director who ensures client deliverables entail robust analysis and clear recommendations (where necessary), along with providing seamless client communication and management. Prior to LEI, he worked for the Investment Banking Division at Citigroup, and assisted on capital market and mergers and acquisition (M&A) transactions.

EDUCATION:

York University Osgoode Hall Law School, Masters of Law – LLM, Energy and Infrastructure Law, 2021

Brandeis International Business School, Masters in Business Administration (MBA), 2008

Lahore University of Management Sciences, Masters of Science in Economics (MSc), 2004; Bachelors of Science (Economics major, Mathematics minor), 2003

EMPLOYMENT RECORD:

From: 2008	**To:** present
Employer:	*London Economics International LLC, Boston, MA* Director (January 2020 to present), Managing Consultant (October 2013 to November 2019), Senior Consultant (December 2009 to September 2013), Consultant (December 2008 to November 2009)
From: February 2005	**To**: July 2006
Employer:	*Citibank, Karachi, Pakistan* Assistant Manager, Corporate Finance/Investment Banking Group
From: January 2004	**To**: February 2005
Employer:	*Eni Group, Karachi, Pakistan*

SAMPLE PROJECT EXPERIENCE:

Regulatory economics and tariff related

- ***Enbridge Gas equity thickness:*** In 2023, London Economics International ("LEI") was retained by the Ontario Energy Board ("OEB") staff as capital structure expert in respect of Enbridge Gas Distribution ("EGD")'s Application (EB-2022-0200). As part of its engagement, LEI supported OEB staff in prepare interrogatories, LEI prepared an independent expert report following a detailed review of the analysis of business and financial risks set out in the application, and provided an independent opinion on the appropriate equity thickness for EGD for the 2024-2028 period.

- ***ROE expert evidence:*** London Economics International LLC ("LEI") was retained by the legal counsel for the Prince Edward Island Regulatory and Appeal's Commission ("IRAC") to provide independent expert evidence on a just and reasonable return on equity ("ROE") for the Maritime Electric Company, Limited ("MECL"), associated with their General Rate Application ("GRA") for 2023-2025

- ***Cost of capital parameter updates for OEB:*** LEI was retained by the Ontario Energy Board ("OEB") to provide updates on the macroeconomic conditions of the utility sector in Ontario. LEI provided variance analysis/trend analysis of cost of capital parameters, including the return on equity and deemed long-term and short-term debt rates based on movements of relevant economic indicators. These were presented as quarterly reports to OEB staff.

- ***Market design, business model design and regulation for an innovative region***: LEI, as part of a consortium with Frontier Economics, was retained by a large Middle Eastern entity in 2021 to develop a high-level energy market design for a 100% renewable energy city, which is also developing one of the world's largest green hydrogen projects. As part of project scope, the consortium was tasked with defining the energy market actors with their respective business models, as well as to shape an appropriate and stable regulatory framework. The project was completed under three key workstreams:
    - WS1: Market design: defining the playing field and the boundary conditions for the city's energy system along the energy value chain to enable achievement of key goals for the city's energy system.
    - WS2: Business model design: defining, within the boundary conditions of the market/system design, a clear view on which actors are required/desired together with their roles, conceptual business models and interfaces along the value chain.
    - WS3: Regulation: based on WS1 and WS2, defining the conceptual foundations of a "fit for purpose" regulatory framework for the city.

  For each of the three workstreams, the team developed options and a ramp-up or implementation plan until 2030, detailing key dependencies, risks and opportunities.

- ***Regulatory framework and identification of rules for activities across the value chain***: Following completion of the above-mentioned engagement, FE and LEI were retained by the same large Middle Eastern entity in 2022 to perform a deep-dive analysis and advise on the "Regulation" workstream. The project involved two work packages:

  - WP1: Regulation and rules. Under this work package, the project team detailed the market operation principles and the required regulations across each value chain activity, which are envisioned to facilitate and operationalize the market design concept selected by the client; and
  - WP2: Contrast of desirable regulation and rules with current law. Under this workstream, the project team provided the client with a detailed contrast of existing country-level laws/regulations with the city's laws/regulations. The team also performed a gap analysis associated with ideal rules and regulations needed to achieve the city's objectives. In addition, the team provided an implementation roadmap, including preparation needed for activation.

- ***Facilitating activation and establish governing role:*** LEI and FE were retained by a large Middle Eastern entity in 2022, with work continuing into 2023 and 2024, to provide support over four work streams:
  - WP1: General regulatory support in priority areas. The project team worked to define the energy sector's vision and objectives, the client's structure, and the processes and approach in priority areas.
  - WP2: Preparation in the structuring of licenses and codes in the lower tiers of legislation to enable industry stakeholders detailed input into the design of the documents.
  - WP3: Structure and content of tier 3 laws from an economic and regulatory perspective. Similar to work package 2, the project team worked to identify several areas of priority and involve stakeholders in the design of the tier 3 laws.
  - WP4: Transition of assets and energy sources. The project team provided insights on priorities, required timelines and technologies and critical elements of the client's vision in implementing a smooth transition of assets to client.

  Amit served as LEI's project manager, and a key member of the team leading the provision of services to the client, including presenting a series of workshops consistent with each area of regulation, to discuss the team's findings and recommendations.

- ***OPG equity thickness expert report:*** In 2021, London Economics International ("LEI") was retained by the Ontario Energy Board ("OEB") staff as capital structure expert in respect of Ontario Power Generation ("OPG")'s 2022-2026 Payment Amounts Application (EB-2020-0290). As part of its engagement, LEI provided analysis of evidence and support to OEB staff to prepare interrogatories, prepared an expert report following a detailed review of the analysis of risk set out in the application and provided an independent opinion on the risk faced by OPG.

- ***Incentive-based ratemaking filing for Malaysian electric utility:*** LEI was retained by the largest electric utility company in Malaysia to provide project management services for the client's 2nd regulatory period ("RP2") performance-based regulation ("PBR") (2018-2020) submission. LEI's scope of work consists of several tasks: propose the policy and governance framework for the PBR submission; provide detailed project plan; assess the PBR Regulatory

Requirement Model; ensure accuracy and timely delivery of RP2 submission workshops and review of overall RP2 report.

- ***Abu Dhabi distribution company study:*** LEI provided peer review of methodology and deliverables for the project by Tetra Tech to review the regulatory treatment of connection charges and large-scale infrastructure investments.

- ***Electricity rate economic impact study:*** LEI was engaged by an industry association for an Industrial Electricity Rate Economic Impact Study in Ontario's manufacturing sector. The scope of work consisted of review of current Ontario industrial electricity rates and rate designs; assessment of competitive electricity rate levels; development of options to change rates in a manner consistent with rate setting principles that is beneficial to industrial consumers and the Province; quantification of economic benefits from appropriate rate adjustments; and consultation with relevant industry and government officials and experts throughout the project.

- ***Peer-group analysis of US IPPs:*** LEI was retained by a private client to perform a peer-group analysis of Independent Power Producers ("IPPs") in the US market. LEI presented research to the client with insights on the key economic, financial and strategic factors contributing to growth of mid-sized companies in the US merchant generation market. LEI identified nine categories of IPPs in the US merchant market and defined a subset of companies to be considered as the peer-group for the client. For the peer-group, LEI reviewed key success criteria of each company including business focus, leadership, growth strategy and financial performance. LEI presented three peer-group companies as case studies to highlight examples of successful players in the US IPP market. Overall, LEI highlighted the implications that current market trends and key success factors of peer-group would have on the company's future growth strategy in the US market.

- ***Development of bilateral contract arrangements***: Amit managed an engagement where LEI was retained by the energy regulator in Saudi Arabia to assist in development of bilateral contract arrangements. The project involved multiple stakeholder engagements including with the Ministry, major electricity generation, transmission and distribution company members, petrochemical industry. The project culminated with staff trainings and submission of a draft bilateral contracts' arrangement plan for the Kingdom.

- ***PBR filing for Ontario gas LDC:*** LEI was engaged by an Ontario gas local distribution company ("LDC") to review its proposed 2014 to 2018 incentive ratemaking ("IR") plan as presented to stakeholders on April 29th, 2013 and to examine case studies of approaches to IR applied to other North American gas distribution utilities. In the case study analysis, the LDC particularly requested LEI to examine approaches to a set list of ratemaking parameters: productivity and X-factor trends, alternative approaches to designing an I-X framework, approaches to establishing inflation factors, approaches in other jurisdictions to applying an Earnings Sharing Mechanism ("ESM"), use of capital trackers for unknown costs, appropriateness of deferral accounts for unaccounted-for gas ("UFG"), and service quality indicators ("SQIs") and how they are measured. LEI was subsequently requested by the LED to provide comments on its draft Settlement Agreement.

- ***Review of rate of permitted return in Hong Kong:*** for the Hong Kong Government, Amit led the LEI team in the review of the rate base and the rate of permitted return for the power companies in Hong Kong under the Scheme of Control Agreements ("SCAs"). This engagement required reviewing the alternatives to using Average Net Fixed Assets as the rate base, examining the assumptions used and methodology to calculate the WACC of power companies, updating the indicative range for the permitted rate of return, and recommending changes to existing rates of return by identifying new international best practices. Following this engagement, LEI was requested again to review the permitted rate of return for Hong Kong based power companies under the SCAs, beginning 2019.

- ***Return on equity evolution in Ontario***: retained by a private client to perform analysis regarding the prospects for transmission return on equity ("ROE") evolution in Ontario. The report included a discussion on (i) the process for determining transmission related ROE in Ontario; (ii) potential changes in the ROE formula and/or base parameters; (iii) historical trends in transmission ROE in the United States and Canada; (iv) expectation of future interest rate trends across North America, particularly Ontario, and effect on transmission ROE; (v) the effect of public versus private ownership of transmission assets on cost of capital/ROE in Ontario; and (vi) potential factors limiting one-to-one magnitude changes in ROE (for example, regulatory lags and avoiding rate shocks).

- ***Development of reliability, storm response and customer service standards for the province of Nova Scotia:*** LEI was retained by the Nova Scotia Utility and Review Board ("UARB") to act as an independent consultant to the Board assisting in the formulation of performance standards for Nova Scotia Power Inc. ("NSPI") in the areas of system reliability, storm response and customer service. Amit led the preparation and submission of a Consultation Paper followed by a technical workshop with stakeholders. He also led the LEI team in responding to various interrogatories and submission of a rebuttal report. Finally, as part of the LEI team, he testified as an independent expert in Halifax at the oral hearing in late September 2016.

- ***Literature review and case studies related to the organization and governance of electricity systems***: LEI was retained by the Department of Energy to perform a review of the organization and governance of electricity systems both cross-jurisdictionally and within the province of Nova Scotia. The scope of work was divided into two main phases: (i) review of international best practices and lessons learned; and (ii) translation of best practices and lessons learned into best fit for Nova Scotia.

- ***Transmission cost causation study in Alberta***: LEI was retained by the Alberta Electric System Operator (AESO) to develop a transmission cost causation study. The study was used for the determination of the AESO's Demand Transmission Service Rate DTS, and was filed with AESO's 2014 tariff application to the Alberta Utilities Commission (AUC). The study covered four main topics: (i) Functionalization of Capital Costs; (ii) Functionalization of Operating & Maintenance (O&M) costs; (iii) Classification of Bulk and Regional System Costs; and (iv) Implementation Considerations. LEI also worked with the AESO to facilitate technical sessions and Negotiated Settlement Agreement (NSA) meetings, which involved in-depth discussions regarding methods used and results. Following these meetings, the AESO filed an application for approval of the NSA (along with the revised cost causation study), which was unanimously supported by all participants in the process.

- ***Restructuring of the power sector institutions:*** In 2017/2018, LEI provided strategic advice to the Ministry of Energy, Industry and Mineral Resources ("MEIM") on the options for the evolution of the Saudi power sector, including the role of the Saudi Electricity Company ("SEC"). Amit managed the engagement where the team considered a number of options available to SEC (e.g. retain its current form, improved, and encouraged to expand overseas, or fully unbundled, and a competitive power market created from its constituent parts). In any of these scenarios, depending on the governance structures deployed and the range of financing options available, LEI also considered how different aspects of Vision 2030 can be achieved.

- ***Analysis of procurement processes to meet standard offer service load:*** LEI was retained by the Delaware Public Services Commission ("PSC") to assist with review of the procurement process for the provision of Delmarva Power & Light Company ("Delmarva Power")'s standard offer services, and to provide information and analysis regarding alternative long-term electricity procurement options for Delmarva Power to meet its Standard Offer Service residential and small commercial retail load.

- ***Review of the Alberta Electricity Framework:*** LEI was retained by the AESO to perform an assessment of the Alberta Electricity Framework, which encompasses the wholesale generation market, retail market, agencies, transmission planning, access, and distribution, as well as the operations of the Alberta Interconnected Electricity System. The analysis included both qualitative and quantitative components.

- ***Assistance related to incentive ratemaking application***: LEI was retained to review a large Ontario gas utility's proposed 2014 to 2018 incentive ratemaking ("IR") plan and to examine case studies of approaches to IR applied to other North American gas distribution utilities. In the case study analysis, LEI examined approaches to a set list of ratemaking parameters: productivity and X-factor trends, alternative approaches to designing an I-X framework, approaches to establishing inflation factors, approaches in other jurisdictions to applying an Earnings Sharing Mechanism ("ESM"), use of capital trackers for unknown costs, appropriateness of deferral accounts for unaccounted-for gas ("UFG"), and service quality indicators ("SQIs") and how they are measured. LEI was subsequently requested by the utility to provide comments on the utility's draft Settlement Agreement, which was accepted by the Ontario Energy Board ("OEB").

- ***Independent expert related to proposed auctioning for the Load Following Service ("LFS") product***: LEI provided an independent evaluation of the proposed auction, including evaluation of the both the product being auctioned and the auction mechanism and key parameters. The LFS product as proposed to be auctioned was meant to represent the "shape risk" in the Regulated Rate Option ("RRO") service. LEI's evaluation considered whether the product and auction mechanism would result in an efficient, competitive, and fair outcome for the Alberta market, RRO providers, potential suppliers of the auctioned product, and customers of the RRO service. LEI prepared a report titled "Independent assessment of proposed market-based determination of shape risk in RRO supply", which was filed with the Alberta Utilities Commission ("AUC").

- ***Capital structure and cost of capital review in Jordan:*** LEI advised the Jordanian regulator on the weighted average cost of capital and optimal capital structure for Jordan's three distribution companies: EDCO, IDECO and JEPCO. The recommended optimal capital structure was consistent with targeted debt service and interest coverage ratios in line with the rating methodology for distribution companies from the global credit rating agencies. Work also included identifying salient risk factors for the distribution companies, identifying appropriate local and international metrics and benchmarks, developing a usable cost of capital model, and providing training workshops for local staff.

- ***Tariff model and regulatory advice to a water and power utility in Saudi Arabia:*** LEI was retained for development of a regulatory framework for a power and water utility not regulated by the government, development of a charter for a new regulatory body, establishment of a recommended tariff structure and accompanying tariff model for its business activities, and filing of tariff petitions with the applicable regulatory authorities for approval. The tariff model separated out business entities such as power, potable water, processed water, industrial wastewater etc. across two jurisdictions.

Asset valuation and transaction advisory work

- ***Review and analysis of power purchase agreements (PPAs), energy conversion agreements (ECAs), financial models and stakeholder interaction/negotiations with counterparties on large generation projects***: In 2024, Amit has been leading an ongoing project in the Middle East where LEI has been retained by a private client for commercial advisory services associated with multiple large generation expansion projects in the Middle East. To address the security of supply concerns, the client expects to sign Energy Conversion Agreements ("ECAs") on fast-track generation projects with counterparties. LEI's role is to assist the client across four milestones for each of the projects: (i) Milestone 1: reviewing non-binding offers and financial models prior to ECA signing; (ii) Milestone 2: Assisting on ECA preparation, negotiation, and review of pertinent documentation; (iii) Milestone 3: Assistance post-ECA signing and submission of documents to lenders/banks; and (iv) Milestone 4: Assisting on Financial Close.

- ***Comprehensive review of multiple power purchase agreements – potential buy side due diligence***: LEI was engaged by a private client for professional services related to assistance with developing underwriting scenarios for a solar portfolio located across several US states. As part of the diligence, LEI reviewed the Seller's model assessing reasonability of re-contracting assumptions for the portfolio across all markets, provided high level commentary around outlook for renewables in key markets, highlighted any other red flags or key concerns that were captured as part of the review, and identified any potential options for performance improvement projects based on the key markets (e.g. repowering, addition of storage, selling to different markets etc.). Amit also led a comprehensive review of over 25 PPAs as part of the due diligence.

- ***Hydroelectric asset acquisition in Maine:*** London Economics International LLC ("LEI") was retained to provide assistance in relation to the potential acquisition of a set of hydroelectric assets in Maine. As part of this process, LEI performed (i) an operating performance and review of the assets in the portfolio; (ii) forecasts for energy, capacity, and Renewable Energy Credit prices over a 20-year timeframe, as well as the development of a revenue profile for the target portfolio; and (iii) an investment review, which included developing the ultimate valuation model and associated report. Amit provided due diligence questions to LEI staff on this engagement.

- ***Litigation support - valuation of a power purchase agreement***: LEI was engaged by counsel to provide an independent valuation of an asset in conjunction with a tax payment challenge for an Alberta generator. LEI assessed the appropriateness of valuations related to the acquisition of a coal-fired generating station. Engagement required developing power pool price forecasts that would have been appropriate as of the valuation date several years previously, as well as estimating a range of asset values using multiple valuation approaches. The engagement also included developing critiques of work prepared by opposing expert witnesses.

- ***Investment advice related to district energy assets***: LEI was retained to analyze revenue/gross margin modules for various district energy assets being considered for acquisition. LEI reviewed information received from the client, including detailed documents in the data room, and presented analysis in a slide deck relating to contract revenues (prices and volumes) and fuel costs (electricity) along with revenue and cost drivers. LEI also presented sensitivity analysis for high/low sales volumes, new customers, expiry dates of existing contracts, and fuel costs.

- ***Bid advice in California***: LEI was retained by a private client to analyze alternative technology solutions in relation to preparation of a bid for a Southern California Edison Company ("SCE") Local Capacity Requirements ("LCR") Request for Offers ("RFO"). Work included: (i) a review of the RFP, PPA and related documents and creation of a working memo on relevant issues; (ii) PoolMod (hourly dispatch simulation model) Base Case and up to four sensitivities for the California market for a 20-year time frame, varying only the technology solutions for the project; (iii) development of an excel pro-forma financial model for comparison of up to four technology alternatives; and development of a brief PowerPoint slide deck.

- ***Advice related to transmission acquisition***: LEI was retained by a private client to evaluate the potential acquisition of incumbent transmission companies located in the Alberta power market. Specifically, the client was seeking assistance in understanding the regulatory regime in Alberta as it relates to transmission ratemaking, as well as potential drivers for transmission asset values in Alberta. LEI provided the client with a PowerPoint presentation focusing on historical background of each of the following subjects, discussing the current state of play related to the subject, and conceptually discussing how important it may be in the overall consideration of value. The subjects discussed were as follows: (i) overview of transmission ratemaking in Alberta; (ii) potential regulatory issues resulting from the transaction; and (iii) potential value drivers (including development of the deemed cost of capital for transmission, evolution of performance-based ratemaking ("PBR") and relevance to transmission, distinguishing between those future capex projects that will retain incumbent preference and those that will be placed into competitive processes, and overall implications of Alberta transmission policy for future interconnected load growth versus behind-the-meter growth).

- ***Valuation associated with coal station contracts***: Amit was extensively involved in the analysis as an external consultant retained by a law firm to provide an independent assessment of costs associated with coal-fired generation units in Alberta, consistent with their underlying power purchase arrangements. The range of cost estimates was developed using pro forma cash flow analysis performed for both owner and buyer under the PPA, by modeling flows of payments under the PPA (and post-PPA life) and using results of forward wholesale price forecasts of the Alberta Power Pool, along with research associated with related environmental regulations on plant refurbishments in the region. The analysis also relied on explicit modeling of revenues and costs and utilized a realistic specific discount rate for both the owner and buyer separately.

- ***Analysis of long-term PPA related to contractual dispute***: LEI served as lead analyst in an expert testimony engagement for a private equity investor in matter related to a contractual dispute regarding a long-term power purchase agreement between a municipal utility located in New England and a landfill gas generator. LEI analyzed the key contractual terms of the PPA and provided a review of how those terms compared to the industry norm when the contract was signed and became effective.

- ***Strategic advice related to entrance in the power sector:*** In late 2017, LEI was retained by a private Middle Eastern client in relation to developing a comprehensive study with a road map and implementation plan for the client's entrance in the power sector nationally and regionally. The key objective of this engagement was to determine where best the client would be positioned in the power generation ecosystem in the country and the region, to create capacity and value. The assessment evaluated opportunities along the power sector value chain and across the following energy types: conventional, renewables (including hydro, wind, solar, geothermal and biomass), and nuclear energy. Amit managed the project involving multiple stakeholder meetings and presentation to the Board.

- ***Investment analysis related to new potential capacity***: LEI was retained by a Canadian power utility to provide advice on long-term Alberta electricity power prices (2010-2030) to inform an investment decision on an 800MW gas-fired power station based on different market parameters and build decisions. The project included a detailed assessment of gas procurement costs and forecast gas price trends. The forecast also made special note of the effect on the market, if any, of the following conditions: (i) greenhouse gas legislation; (ii) increase in unconventional (shale) natural gas production; (iii) effect of the enactment of Bill 50; and (iv) effect on the market by external jurisdictions. LEI was asked to provide two subsequent updates for the company's board of directors on the status of the project.

- ***Privatization transaction***: Amit was part of the advisory team to the Government of Pakistan on potential privatization of one of the largest public sector enterprises. Involved strategic industry and financial analysis, due diligence, and working with potential buyers

- ***Capital syndication transaction for a cement company***: Worked as a lead team member in a capital syndication transaction involving eight corporate financial institutions for a takeover and long-term financing for a cement plant. Work involved financial modeling and future long-term cash flow forecasts.

Renewable energy analysis

- ***Analysis of potential Canadian clean energy exports:*** LEI was retained by Corporate Knights Inc. to perform a high-level estimation and analysis of potential opportunity for developing clean energy exports from Canadian markets to target US power markets. An LEI staff member also travelled to Calgary, Alberta to present the analysis at the ABB Energy and Automation Forum.

- ***Impact of regulatory delays for renewable projects globally***: The IEA's Implementing Agreement for Renewable Energy Technology Deployment (IEA-RETD) retained LEI, in consortium with 3E (based in Belgium) to carry out a study on the impact of regulatory delays and uncertainty. The project developed a model to estimate the cost of regulatory delays to renewable energy industry and the broader economy and documented its validity through a number of case studies.

- ***Potential for low carbon energy exports in North America***: LEI was retained by a private client to perform a high-level estimation and analysis of potential opportunity for developing low carbon energy exports from Canadian markets to target US power markets. LEI submitted a detailed PowerPoint slide deck and presented its analysis to key industry stakeholders at the ABB Energy and Automation Forum.

- ***Development of a comprehensive renewable energy procurement plan***: Amit managed a firm engagement where LEI was retained by a large Middle Eastern client involving development of the renewable energy competitive procurement process (CPP), customized feed in tariff (FIT) program, sustainable energy procurement company (SEPC), and a procurement leverage strategy (PLS). The client's objective of procuring significant amount of renewable energy by 2032 had to be carefully balanced with competing objectives related to macroeconomic development. The work conducted by the project team consisted of four interrelated "modules": (i) detailed design of a CPP and underlying documents; (ii) detailed design of a robust and flexible FIT building upon the design of the CPP and underlying documents; (iii) company framework documents for the formation of a creditworthy SEPC (covering the legal and regulatory framework, mandate, board structure and composition, business and human resources plans, and organizational structure); and (iv) algorithmic model and detailed strategy for a procurement leverage strategy infused throughout other modules, promoting the client's objectives in terms of job creation, local content, training, and research & development. Throughout the engagement, international best practices (building on case studies covering 18 jurisdictions) were taken into account and translated into best fit for the Saudi economic, legal, regulatory, and financial context. The engagement was structured so that implementation is essentially a matter of "pushing the button": templates, contract forms, online frameworks, promotional material, etc. were created.

- ***Development of a financial, commercial, and regulatory framework for renewable and atomic energy***: Amit was a key member of the project team involved in the development of a financial, commercial, and regulatory framework, as well as drafting an investment strategy and model for a large Middle Eastern private client. Deliverables included: (i) a master plan on how to develop renewable and atomic energies based on local value chains in the country; (ii) an economic framework to create a favorable environment in order to follow this master plan; (iii) an investment strategy to make use of in-country resources and available funds in an efficient way; (iv) a multitude of international case studies to avoid costly mistakes in the future and to know when to adopt; (v) a final report on 'National Policy for Investment in Alternative Energy Sources'; and (vi) two 'sales pitch' documents submitted to the Supreme Council and to the financial community.

- ***Renewable energy fund analysis for first nations***: LEI analyzed costs related to the development of renewable energy projects in aboriginal communities and assisted the client in the establishment of the Aboriginal Renewable Energy Fund. The Fund's aim was to provide grants based on a list of potential activities associated with the development of renewable energy projects.

- ***Municipal renewable energy fund analysis:*** LEI investigated the types of costs incurred by a municipality when hosting a renewable energy project. Amit and the team identifying which of these costs are paid for by the developer, and which are paid for by the municipality, in order to assist the client in the establishment of the Municipal Renewable Energy Fund. The Fund's target was to provide grants to municipalities for direct costs of hosting renewable projects, which are not covered by developers.

- ***Evaluation of feed in tariff applications***: LEI monitored of the application review process under the FIT program administered via the Green Energy Act in Ontario. Work involved evaluating FIT applications independently and validating results with those obtained by the client.

- ***Advice related to wind farm investment***: Examined and modeled long term energy price forecast scenarios for the Electric Reliability Council of Texas ("ERCOT") power market, where client considering investment in a wind farm in one of the ERCOT zones.

- ***Development of a solar project in Vermont***: Amit assisted an LEI client in successful development of a greenfield solar project in Vermont. Key tasks involved assistance in permitting, coordinating with EPC suppliers on quotes, discussing financing and leasing alternatives with banks and other investors, and negotiating property tax matters with the town, among other matters.

- ***Asset management services for a small hydro portfolio***: On behalf of an LEI private client, Amit provides asset management services for an existing renewable (small hydro) portfolio of assets in the US. In his role, Amit performs detailed economic and financial analyses, assists with regulatory filings, oversees property tax and insurance related matters, and is involved in business development and product marketing activities (such as net metering).

ORAL TESTIMONY

- ***Testified as capital structure expert in July 2023 respect of Enbridge Gas Inc. ("EGI")'s Application (EB-2022-0200).***

- ***Testified in front of Nova Scotia Utility and Regulatory Board in September 2016 in relation to implementing performance stands related to reliability, customer service and storm response for Nova Scotia Power*.**

- ***Testified at the Alberta Utilities Commission in relation to independent evaluation of auction mechanisms associated with Load Following Service ("LFS") product.***

SPEAKING ENGAGEMENTS:

- "***Energy Finance and Trading***" Invited to be Chair and Presenter for this conference session. International Association of Energy Economics ("IAEE") conference, Istanbul. June 2024.

- ***"Changes in Effective Load Carrying Capacity ("ELCC") for solar PV in KSA at various levels of penetration."*** Presenter, International Association of Energy Economics ("IAEE") conference, Riyadh. February 2023.

- ***"Energy 2020: Reducing Your Energy Costs"*** Panelist, Canadian Manufacturers & Exporters ("CME"), Toronto. February 2020.

Shashwat Nayak

Senior Consultant, London Economics International LLC

LONDON ECONOMICS

KEY QUALIFICATIONS:

Key Qualifications:

Shashwat Nayak is a Senior Consultant at LEI. He has six years of experience in the electricity sector. He joined LEI in 2022 and has been primarily focused on projects related to the energy sector in Ontario. Shashwat has supported multiple regulators and utilities in engagements, including support in Alberta PBR filing, recommending an appropriate capital structure for Enbridge Gas Inc. and providing quarterly updates to the OEB on cost of capital/inflation parameters. Shashwat was also qualified as an expert witness for testimony on behalf of the OEB staff regarding appropriate equity thickness for Enbridge Gas Inc. [OEB, proceeding ID: EB-2022-0200].

Prior to joining LEI, Shashwat worked as a Management Consultant in the 'Energy Utilities and Resources' practice of PwC India. He has hands-on experience in policy, regulatory and financial aspects of the electricity and other infrastructure sectors. He has assisted multiple regulators (at the federal and state level in India), utilities (power generation, power transmission, power distribution, water collection, water treatment, etc.), think tanks and other private sector entities in financial advisory, bid advisory, risk management, electricity sector reforms, developing Multi-Year Tariff ("MYT") regulations, drafting/ reviewing utility business plans and capital expenditure plans, tariff/rate determination, policy advocacy, determination of accurate cost of electricity supply etc.

Education:

Institution	Xavier Institute of Management, Bhubaneswar (India)
Date:	March 2018
Degree(s) or Diploma(s) obtained:	MBA in Business Management (with a major in 'Finance')

Institution	B. M. S. College of Engineering, Bengaluru (India)
Date:	June 2013
Degree(s) or Diploma(s) obtained:	Bachelor of Engineering (Information Science & Engineering)

Employment Record:

Date:	August 2022 – Present
Location:	Toronto, ON (Canada)
Company:	London Economics International LLC ("LEI")
Position:	Senior Consultant

Date:	May 2018 – June 2022
Location:	Gurgaon, India
Company:	PricewaterhouseCoopers Pvt. Ltd. ("PwC India")
Position:	Manager (April 2022 – June 2022) Senior Consultant (October 2020 – March 2022) Consultant (May 2018 – September 2020)

Date:	August 2013 – August 2015
Location:	Bengaluru, India
Company:	Tata Consultancy Services Ltd.
Position:	Systems Engineer

Recent project experience (LEI):

Date:	January 2023 – August 2023
Location:	Toronto, ON (Canada)
Company:	Ontario Energy Board
Description:	**Capital structure expert for Enbridge Gas** LEI was engaged by the OEB staff as a cost of capital / capital structure expert to review Enbridge Gas' application for 2024 rebasing and 2025-2028 price cap plan. LEI's responsibilities includes analyzing the evidence and assisting OEB staff in preparing interrogatories, independent expert evidence, and participating in the technical conference following the review of interrogatory responses.

Date:	July 2019 (project start date) – Ongoing
Location:	Toronto, ON (Canada)
Company:	Ontario Energy Board
Description:	**Quarterly updates on cost of capital parameters and macroeconomic developments** LEI has been retained by the OEB to provide quarterly updates on the macroeconomic conditions of the utility sector in Ontario. LEI provides variance analysis/trend analysis of interest rates, inflation factors and cost of capital parameters, including the Return on Equity and deemed long-term and short-term debt rates based on movements of relevant economic indicators. These are presented in the form of quarterly reports.

Date:	June 2022 – February 2023
Location:	Charlottetown, PE (Canada)
Company:	Carr, Stevenson & MacKay (legal counsel to Prince Edward Island Regulatory and Appeals Commission)
Description:	**Recommendation of a just and reasonable ROE for Maritime Electric Company, Limited ("MECL")** LEI was engaged to provide independent, expert evidence to Prince Edward Island Regulatory and Appeals Commission ("IRAC") regarding a just and reasonable ROE for MECL.

Date:	October 2022 – April 2022
Location:	North Dakota
Company:	North Dakota Public Service Commission
Description:	**Montana-Dakota Utilities rate case** LEI was engaged by the North Dakota Public Service Commission as the outside independent technical consultant supporting the Commission's ratepayer advocacy staff in a rate case involving Montana-Dakota Utilities. LEI examined key components of the rate case, which included the depreciation study, tax rates, environmental upgrades, transmission investment, the ROE/common equity ratio, amortization for early retirement of coal plants, and impacts on residential rates versus impacts on other classes of service. LEI prepared data requests and provided written and oral testimony. Barbara worked on the sections of the audit related to depreciation and environmental upgrades.

Date:	January 2024 – Ongoing
Location:	Maine
Company:	Maine Public Utilties Commission
Description:	**Alternate procurement options for Maine** LEI was retained by the Maine Public Utilities Commission to explore alternative procurement mechanisms associated with procuring standard offer service ("SOS"). The objective of the study is to review the status quo mechanism in Maine, perform a review of alternative approaches and SOS procurement mechanisms in other New England Independent System Operator jurisdictions, and provide recommendations for Maine that may result in higher price stability and/or reduced SOS prices.

Date:	October 2023 – February 2024
Location:	Ontario
Company:	Confidential
Description:	**Expert witness services in a legal proceeding** LEI was engaged by an international law firm to provide expert witness services in a legal dispute regarding interpretation of a Feed-in Tariff contract for a rooftop solar facility in Ontario.

Date:	November 2023 – January 2024
Location:	Ontario
Company:	Confidential
Description:	**Expert witness services in a legal proceeding** LEI was retained by a renewable energy generator to provide evidence in a confidential legal proceeding, which ultimately reached a resolution satisfactory to the parties.

Date:	January 2023 – December 2023
Location:	Ontario
Company:	Ontario Energy Board
Description:	**Benchmarking reliability for Ontario LDCs**

	LEI was retained by the OEB to develop a customized reliability benchmarking model for the Ontario electricity distribution sector, while also proposing reliability performance expectations to enhance utility accountability to customers. The engagement involved completing the following tasks in consultation with the OEB staff and the RPQR Working Group: (i) identify a set of potential approaches to benchmarking reliability by assessing the status quo in Ontario and other North American international jurisdictions; (ii) develop a straw man benchmarking model and set reliability performance expectations; and (iii) finalize benchmarking model and the proposal for reliability performance expectations.

Date:	October 2022 – March 2023
Location:	Alberta (Canada)
Company:	ENMAX
Description:	**Preparation of expert testimony related to performance-based ratemaking ("PBR"):** LEI was engaged by ENMAX to provide expert evidence and assist in its participation in the Alberta Utilities Commission ("AUC") proceeding to establish parameters for the third PBR term in the province (AUC Proceeding 27388). LEI provided recommendations related to the timing of PBR rate adjustments, merits of the price cap versus revenue-per-customer cap approaches, I factor, X factor, capital funding provisions, earnings sharing mechanisms, and quantifying and tracking efficiencies. LEI based its recommendations on industry best practices as well as analysis of Alberta-specific data.

SAMPLE PROJECT EXPERIENCE (PwC India):

- ***Assistance to Central Electricity Regulatory Commission (CERC):*** Assistance to CERC (federal electricity regulator in India) in review & scrutiny of 50+ tariff applications filed by utilities (generation & transmission), revision of revenue requirement of prior periods based on audited accounts, projecting the revenue requirement for the upcoming period and accordingly finalizing the regulatory tariffs for the utilities based on these projections

- ***Assistance to Indian regulatory authorities such as Joint Electricity Regulatory Commission (JERC) & Punjab State Electricity Regulatory Commission (PSERC):*** Formulation of Multi Year Tariff (MYT) Regulations for periods FY 2019-2022 (JERC) and FY 2020-2023 (PSERC) respectively. Assistance in review and analysis of Business Plan and Capital Investment Plan (CIP), submitted by distribution companies in the state of Goa and 6 Union Territories (UTs) in case of JERC, and State-owned transmission and distribution utilities of the state of Punjab (PSTCL & PSPCL) in case of PSERC. The engagements involved forecasting energy sales, connected load & consumer base, preparation of power purchase plan and evaluation/approval of CIP of the utilities. Review and approval of tariff applications filed by the Generation, Transmission and Distribution utilities.

- ***Assistance to utilities in regulatory submissions:*** Supported a Middle East based client in regulatory submissions by developing financial models for calculating tariffs/rates for power (generation/transmission/distribution) & water sector (desalination/collection/distribution /wastewater treatment etc.) utilities. Assessing the financial impact of various decisions of regulatory bodies and judicial authorities (including the Supreme Court of India) on an Indian distribution utility and providing suitable recommendations based on the assessment.

Assisting various utilities such as Power Transmission Company of Uttarakhand (PTCUL) & Himachal Pradesh State Electricity Board (HPSEB) in in preparation of application/ petition for determination of tariff for multiple years, preparation of financial model based on applicable regulations, support during technical validation of the application, support during public consultation, analysis of Order by the state regulatory commission and recommendations on further course of action based on the Order. Assistance to a federal government owned central transmission utility and a federal government owned hydropower generation company, in policy advocacy & impact assessment of CERC tariff Regulations applicable for the period from FY 2019-24.

- ***Advice on electricity sector reforms:*** Assisted an international financial institution in developing structural reform options in the Indian electricity distribution sector by introducing choice/competition in the retail supply of electricity. Supported a prominent think tank funded by USAID in conducting a study on regulatory interventions for grid discipline and grid reliability for 8 countries in the South Asian Region. Assisted a prominent Indian think tank in developing a financial model for computing cost of supply of electricity to various class of consumers and building a framework to assess affordability of electricity tariffs.

- ***Assistance in bid submission:*** Assisted a European multinational utility in the bidding process for privatization of an Indian electricity distribution utility, including regulatory & commercial due diligence and preparing financial projections for the target utility.

- ***Assistance in formulating a market entry strategy:*** Assisted a European multinational utility in developing a market entry strategy for electricity trading in Indian wholesale energy markets.

TAB 9

Figure 20: Jurisdictional Comparison of Financing and Flexibility Adjustment

Jurisdiction	Adj.	Docket/Proceeding	Notes
Alberta	50 bps	2018 GCOC Decision 22570-D01-2018 and 2024 GCOC Decision 27084-D02-2023	Adjustment of 50 bps is normally included in the allowed return to account for administrative and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.
British Columbia	50 bps	2013 GCOC Decision Stage 1, and 2016 FEI Decision	Has previously approved 50 bps adjustment but cautioned that it should not be considered "automatic" and instead should be considered on a case-by-case basis. (see note above on most recent decision)
Manitoba	N/A	N/A	N/A
New Brunswick	50 bps	2010 EG Decision	Accepted 50 bps as being the lower of two proposed adjustments presented.
Newfoundland and Labrador	50 bps	P.U. 13(2013), and P.U. 18(2018)	Accepted 50 bps adjustment
Nova Scotia	N/A	2023 NSUARB 12	The 2023 Nova Scotia Power rate application was resolved through a settlement agreement that specified an authorized ROE but did not indicate whether that return included flotation costs and/or financing flexibility.
Ontario	50 bps	EB-2009-0084	Base ROE value included a 50 bps adjustment for flotation and financing flexibility.
Prince Edward Island	50 bps	Order UE19-08	Approved ROE included a 50 bps adjustment for flotation costs.
Saskatchewan	N/A	N/A	N/A
Quebec	30-40 bps	D-2011-182/R-3752-2011	Regie determined provision for flotation costs and other costs of accessing capital markets ranging from 30-40 bps, with a greater weighting at the lower end of the range.

TAB 10

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, p. 128

Question(s):

Note this interrogatory has been asked by LEI.

Concentric stated the following:

On that basis and as further discussed below, we find that these Ontario electric and gas utilities have higher financial risk than the North American proxy groups.

a) Please confirm if major credit rating agencies widely share this view and provide relevant specific examples.

Response:

a) The “basis” discussed in the referenced part of Concentric’s report refers to the fact that Ontario’s electric transmission and distribution utilities have similar deemed equity ratios as other electric utilities in Canada but substantially lower equity ratios than their U.S. counterparts, and that Ontario’s gas distributors have somewhat lower deemed equity ratios than other gas distribution companies in Canada and substantially lower equity ratios than their U.S. peers. The major credit agencies share this view. For example, in a July 2024 Credit Opinion update, Moody’s notes “[Hydro One’s] relatively weak financial metrics are primarily the result of its low authorized equity layer in the capital structure (currently 40%) that is established by the OEB.”[1] Further, Moody’s cites the company’s weak financial metrics driven by the low authorized equity capital as one of the Company’s main credit challenges.

[1] Moody’s Ratings, “Credit Opinion: Hydro One Inc,” July 26, 2024.

According to DBRS Morningstar, the Canadian credit rating agency, Ontario regulation is generally credit supportive. DBRS has observed, however, that deemed equity ratios and authorized returns on equity are lower in Ontario than in many other North American jurisdictions. DBRS rates the regulatory environment for regulated utilities on eight criteria on a five-point scale from Excellent to Poor (i.e., Excellent, Good, Satisfactory, Below Average, and Poor). The Figure below summarizes those factors for various Ontario utilities:

Criteria	**Toronto Hydro**[2]	**OPG**[3]	**Hydro One Networks**[4]	**Alectra**[5]
Deemed Equity	Satisfactory	Good	Satisfactory	Satisfactory
Allowed ROE	Satisfactory	Satisfactory	Good	Satisfactory
Energy Cost Recovery	Excellent	N/A	Excellent	Excellent
Capital and Operating Cost Recovery	Good	Good	Good	Good
Cost of Service vs. Incentive Rate Mechanism	Satisfactory	Satisfactory	Good	Satisfactory
Political Interference	Below Average	Below Average	Below Average	Below Average
Stranded Cost Recovery	Good	Satisfactory	Good	Good
Rate Freeze	Good	Below Average	Satisfactory	Satisfactory

Similarly, in their most recent updates to their credit reports, Moody's and S&P both noted the high levels of execution risk in OPG's plan to refurbish the Darlington Nuclear

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2 DBRS Morningstar, Rating Report Toronto Hydro Corporation, May 1, 2023, at 9.
3 DBRS Morningstar, Rating Report Ontario Power Generation Inc., April 30, 2024, at 14.
4 DBRS Morningstar, Rating Report Hydro One Networks, Inc., November 20, 2023, at 11.
5 DBRS Morningstar, Rating Report Alectra Inc., June 22, 2021, at 12.

Plant could pressure the company's credit quality over time.[6,7] Notably, Moody's further highlights the lack of clarity regarding OEB's regulatory support in the Company's completion of its Pickering refurbishment and small modular reactor ("SMR") reactor project.

Investors' perception of higher financial, execution, and regulatory risk signal that an investment in the utility's equity should constitute a higher return commensurate with that risk. During times of high capital spending or evolving financial conditions, the ability to attract capital at a reasonable cost is of paramount importance. Periodic regulatory reviews of established ROEs and capital structures can assist in managing a utility's ability to access the capital markets.

6 Moody's Ratings, "Rating Action: Moody's Rating affirms Ontario Power Generation ratings; outlook stable," May 29, 2024.
7 S&P Ratings Direct, "Ontario Power Generation Inc.," August 8, 2023.

TAB 11

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, Figure 16, p. 66

Question(s):

Note this interrogatory has been asked by LEI

Concentric presented a chart on “Value Line and Bloomberg Betas” in Figure 16 on this page.

a) Please provide the backup calculations for the derivation of the Betas provided in the Figure (in MS Excel worksheet)

b) Please provide the breakdown of raw betas, and how the raw beta was adjusted, for each company in the six proxy groups (in MS Excel worksheet).

Response:

a) Please see N-M2-10-OEB Staff-12(a), Attachment 1 for the requested data. Value Line betas are taken from the summary sheet for each company; Bloomberg betas are downloaded directly from Bloomberg based on inputs of the user. No additional calculations were made to produce the betas for each utility company.

b) Please see N-M2-10-OEB Staff-12(b), Attachment 1 for the requested data. Value Line reports Blume-adjusted betas. Concentric used Value Line’s most recently reported betas for each company in the proxy group as of May 31, 2024. Bloomberg reports raw and adjusted betas. Concentric used Bloomberg’s most recently reported 5-year Blume adjusted betas for each company in the proxy group as of May 31, 2024.

   To convert an adjusted Beta to a raw Beta, Concentric used the formula:

   Raw Beta = (Adj. Beta – (1/3)) x (3/2).

TAB 12

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

EDA Report, pp. 43 & 46 & 84
Dr. Cleary Report, pp. 29 & 44
Concentric Report, pp. 136 & 137

Question(s):

Nexus stated that "capital from US exchanges is equivalent to capital from Canadian exchanges."

Nexus' proposal is that the OEB retain its existing policy regarding capital structure applicable to electricity distributors for now.

Dr. Cleary stated that U.S. utilities are not reasonable comparators for Canadian utilities. In Dr. Cleary's view, this is true because they have significantly higher business risk – partly due to their holding company structure and business holdings, partly due to operating in the U.S. and not in Canada, and partly due to the nature of their operations which entail more risk.

Concentric stated that it finds that Ontario's regulated distribution and transmission utilities generally have comparable business risk to the companies in the North American Electric and Gas comparator groups. Concentric also concluded that Ontario's utilities have similar financial risk to other electric and gas utilities in Canada and substantially greater financial risk than their U.S. peers due to the relatively low deemed equity ratios of 38 percent for Enbridge Gas, 40 percent for electric distribution and electric transmission, and 45 percent for OPG.

Concentric stated that an immediate move to parity with the U.S. would be abrupt. For that reason, Concentric recommended that the OEB set a minimum deemed equity ratio for Ontario utilities of 45 percent, which is at a point approximately halfway between the Ontario level and the U.S. average.

a) Concentric – please provide Concentric's views on Dr. Cleary's statement that U.S. utilities are not reasonable comparators for Canadian utilities.

b) Concentric – please explain why a minimum deemed equity ratio for Ontario utilities of 45 percent is appropriate, given Dr. Cleary's statements noted above, and Nexus' recommendation to keep the status quo.

Response:

a) Concentric disagrees with Dr. Cleary's conclusion that U.S. utilities are not reasonable comparators for Canadian utilities. In fact, as discussed in the Concentric report (at 51-52), Exhibit M2, both the BCUC and the AUC have accepted the use of a North America proxy group comprised of utility companies in both Canada and the U.S. to set the authorized ROE for utilities under their jurisdiction. In addition, as discussed on page 50 of Concentric's report, the OEB determined in 2009 that U.S. utilities can be used as comparators to Canadian utilities for purposes of establishing the authorized ROE. Also, in September 2013, Moody's published a report in which the rating agency changed its previous view that U.S. utilities had greater regulatory risk than their peers in Canada. Moody's ultimately concluded that U.S. utilities have similar regulatory risk as Canadian utilities, noting the increased use of forecast test years in the U.S. and the adoption of adjustment clauses and cost recovery mechanisms that enhanced the timeliness of cost recovery for U.S. companies and reduced regulatory lag.

   Further, Concentric's experience suggests that equity analysts perceive the U.S. and Canada as part of an integrated North American market for capital. This is demonstrated by a March 2019 report by equity analysts at Scotiabank indicating that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed: "Canadian and U.S. valuations should converge. Historically, the Canadian utilities have traded at a premium to their mid-cap U.S. peers. We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (***we no longer have that view***) as well as to strong earnings growth in part due to M&A. As shown in Exhibit 19, based on forward consensus estimates, the Canadian names now trade at a 3x discount."[13]

b) Concentric has included U.S. companies in our North American proxy group analysis. Our recommended 45% minimum equity thickness falls short of parity with U.S. equity ratios, which, as described in the Concentric report, at page 134, average 51% for electric companies and 52% for gas LDCs.

Nexus' proposal is that the OEB retain its existing policy regarding capital structure applicable to electricity distributors for now. However, Nexus adjusts its authorized ROE recommendation to account for differences in financial leverage. Specifically, Nexus, at page 6, stated that they adjusted their ROE results "for differences in leverage to the Deemed Debt Rate of 60 percent. In this way, we put the results on the same financial risk footing as Ontario." As such, while Nexus has not recommended a change in equity thicknesses for Ontario utilities, Nexus has accounted for Ontario's lower equity thicknesses through its leverage adjustment, which "eliminate[s] financial risk as a cause for differentiation among cost of equity estimates." Further, Nexus observes at page 84 of their report that "[f]irst, a 50:50 Debt-to-Equity ratio for regulated electric utilities is common in the US. Second, Debt ratios greater than 60 percent are fairly rare. Third, Ontario's Deemed Debt-to-Capital Ratio of 60 percent is higher than those of the Comparable states (New York and California) identified by LEI in its report. British Columbia and Alberta have Deemed Debt Ratios of 55 percent."

TAB 13

Energy Probe Interrogatory # N-M1-1-EP-2

Interrogatory

Reference:

Exhibit M1, page 50

Preamble:

At page 50, LEI states:

"The Supreme Courts in both the US and Canada have upheld that publicly owned utilities are entitled to a fair return on equity, in the same way that privately owned utilities are entitled to earn a fair return. This will enable utilities to finance their capital investments appropriately.

In Bluefield Waterworks & Improvement Company v. Public Service Commission of the State of West Virginia et al (Bluefield) the US Supreme Court stated: '*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*.'"

Question(s):

a) Was the Bluefield Waterworks & Improvement Company owned by the City of Bluefield, West Virgina or by private investors?

b) Public utility is an organization that supplies the public with water, gas, or electricity according to Cambridge Dictionary. The word public does not refer to ownership. Does LEI agree with that definition?

Response: Note that this interrogatory response has been prepared by LEI.

a) While this case is from 1923, meaning ownership records are difficult to review, the case would not have come before the court were the utility not operated on a commercial (for profit) basis.

b) LEI disagrees. The meaning of the word "public utility" depends on context. In some cases, the definition is as suggested. However, in other cases, the word may refer to a government-owned entity.

TAB 14

School Energy Coalition Interrogatory #N-M1-0-SEC-2

Interrogatory

Reference:

Exhibit M1

Question:

Please provide LEI's views on the recommendations and analysis contained in the expert report from Dr. Clearly on behalf of AMPCO/IGUA.

Response: Note that this interrogatory response has been prepared by LEI.

LEI's disagreement with Dr. Cleary's report primarily relates to Issue 10 (determination of ROE). LEI believes that Dr. Cleary's recommendation of 7.05% does not meet the FRS. Dr. Cleary relies heavily on a small sample size of Canadian companies. The Canadian companies are mostly holding companies with significant operations in the US, which further adds to the argument that the US data is relevant for determining ROE. The eight major pension funds in Canada (informally known as the Maple 8) allocate only about 25% of their portfolio to domestic Canadian investments, which indicates that investors are more likely to consider their investment opportunity costs.[13,14] As such, the ROE methodology needs to consider US returns. However, this does not necessarily mean that the outcome of the methodology needs to match US returns exactly to be valid.

[13] Omers. Terms Explained: Pensions. November 12th, 2021.

[14] The Globe and Mail. Opinion: Pension funds need to seek out more investments in Canada. November 30th, 2023.

TAB 15

Potential alternatives for ROE determination

The OEB may consider the following options for ROE methodology:

1. Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads, and adjustment factors based on current data;
2. Same as #1 but determining base ROE with the discounted cash flow ("DCF") approach instead of the ERP approach;
3. Same as #1 but determination of adjustment factors using multivariate regression analysis;
4. Determination of base ROE using CAPM and adjustment of ROE using CAPM formula parameters;
5. Determination of base ROE using CAPM, with ROE updated annually using adjustment factors determined in #3; and
6. Determination of an average base ROE from CAPM, ERP and DCF methodologies, with annual updating of ROE based on #3.

In subsequent paragraphs, LEI has discussed the above alternatives in more detail.

1. Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads and adjustment factors based on current data

LEI analyzed the historical premiums observed between 30-year GoC bond yields and returns from the S&P/TSX composite index (total returns, including dividend returns) and from the BMO equal weight utilities index ETF to determine base ROE based on the ERP approach. This is similar to Dr. J.H. Vander Weide's ERP approach in EB-2009-0084. This approach, using current data, yielded an ERP of 5.5% (as presented in Figure 36).

Figure 36. Determination of updated ERP

Comparable group	Period of analysis	Average stock return	Average bond yield	ERP
S&P/TSX composite (total return) index	2001-2024	6.77%	3.37%	3.40%
BMO equal weight utilities index ETF	2010-2024	10.98%	3.37%	7.60%
Average				**5.50%**

Sources: S&P Capital IQ, Bloomberg, BMO.

The base LCBF using March 2024 data is 3.15%. As such, the base ROE is 8.65% (3.15% + 5.50%) using the existing methodology.

To determine the LCBF adjustment factor, LEI used regression analysis for the 2001 to 2023 period. To maximize the data points for regression analysis, LEI utilized quarterly data instead of annual data (see Appendix 7). The weighted average ROEs allowed by US regulators for

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Figure 36. Determination of updated ERP

Comparable group	Period of analysis	Average stock return	Average bond yield	ERP
S&P/TSX composite (total return) index	2001-2024	6.77%	3.37%	3.40%
BMO equal weight utilities index ETF	2010-2024	10.98%	2.50%	8.48%
Average				**5.94%**

Sources: S&P Capital IQ, Bloomberg, BMO.

The base LCBF using March 2024 data is 3.15%. As such, the base ROE is 9.09% (3.15% + 5.94%) using the existing methodology.

To determine the LCBF adjustment factor, LEI used regression analysis for the 2001 to 2023 period. To maximize the data points for regression analysis, LEI utilized quarterly data instead of annual data (see Appendix 7). The weighted average ROEs allowed by US regulators for

The results from the options presented by LEI are summarized in Figure 46 below.

Figure 46. Summary of ROE options

Alternative #	Description	Base ROE value	LCBF adjustment factor	Corporate bond yield spread adjustment factor
1	Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads, and adjustment factors based on current data	8.65%	0.39	0.33
2	Same as #1 except determining base ROE with the discounted cash flow ("DCF") approach instead of the ERP approach	10.77%	0.39	0.33
3	Same as #1 but determination of adjustment factors using multivariate regression analysis	8.65%	0.26	0.13
4	Determination of base ROE using CAPM and adjustment of ROE using CAPM formula parameters	**Average: 8.95%** High: 10.22% Low: 8.23%	N/A	N/A
5	Determination of base ROE using CAPM, with ROE updated using adjustment factors determined in #3	**Average: 8.95%** High: 10.22% Low: 8.23%	0.26	0.13
6	Determination of an average base ROE from CAPM, ERP and DCF methodologies, with updating of ROE based on #3	9.46%	0.26	0.13

Notes:

(i) LEI recommended alternative is highlighted.

(ii) The ROEs allowed by US regulators in 2022 and 2023 rate cases have ranged between 7.85% and 11.45% (Source: S&P Capital IQ).

(iii) For each alternative presented above, the base ROE value and adjustment factors are to be updated after five years; $LCBF_t$ is to be updated annually in October/November of every year as per the methodology described in Figure 26 (latest 30-year GoC bond yield forecasts for the subsequent year from major Canadian banks); $UtilBondSpread_t$ is to be updated annually in October/November of every year based on the 12-month average (data from October of the previous year to September of the current year) for the BVCAUA30 BVLI Index.

Potential alternatives for frequency of updating ROE

The OEB may consider the following options for updating ROE:

1. **Status quo:** ROE is updated annually using a formulaic approach. The prevailing ROE during the year of rate case filing is applicable for the entire IRM period.

2. **Set ROE for the five upcoming years** and update the ROE every five years (for the next five years) based on new data.

4.10.4 Recommendations

LEI prefers to use CAPM for base ROE determination (alternative #5). Beta is a useful indicator in measuring sector-specific risk (which the ERP methodology lacks). Due to the stable returns

The results from the options presented by LEI are summarized in Figure 46 below.

Figure 46. Summary of ROE options

Alternative #	Description	Base ROE value	LCBF adjustment factor	Corporate bond yield spread adjustment factor
1	Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads, and adjustment factors based on current data	9.09%	0.39	0.33
2	Same as #1 except determining base ROE with the discounted cash flow ("DCF") approach instead of the ERP approach	10.77%	0.39	0.33
3	Same as #1 but determination of adjustment factors using multivariate regression analysis	9.09%	0.26	0.13
4	Determination of base ROE using CAPM and adjustment of ROE using CAPM formula parameters	**Average: 8.95%** High: 10.22% Low: 8.23%	N/A	N/A
5	Determination of base ROE using CAPM, with ROE updated using adjustment factors determined in #3	**Average: 8.95%** High: 10.22% Low: 8.23%	0.26	0.13
6	Determination of an average base ROE from CAPM, ERP and DCF methodologies, with updating of ROE based on #3	9.60%	0.26	0.13

Notes:

(i) LEI recommended alternative is highlighted.

(ii) The ROEs allowed by US regulators in 2022 and 2023 rate cases have ranged between 7.85% and 11.45% (Source: S&P Capital IQ).

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The OEB may consider the following options for updating ROE:

1. **Status quo:** ROE is updated annually using a formulaic approach. The prevailing ROE during the year of rate case filing is applicable for the entire IRM period.

2. **Set ROE for the five upcoming years** and update the ROE every five years (for the next five years) based on new data.

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LEI prefers to use CAPM for base ROE determination (alternative #5). Beta is a useful indicator in measuring sector-specific risk (which the ERP methodology lacks). Due to the stable returns