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

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

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

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

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

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

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

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

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1 Introduction

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

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

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

Organization of this Report

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

2 Consultative Process

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

2.1 Overview

Initial Consultation

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

Cost of Capital Review

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

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

The Issues List

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

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

The Board identified three areas where further information was needed:

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

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

The Stakeholder Conference

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

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

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

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

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

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

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

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

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

2.2 Approach to Developing Regulatory Policy

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

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

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

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

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

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

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

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

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

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

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

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

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3 Context, Background and the Role of the Board

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

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

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

3.1 Fair Return Standard

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

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

Second, the Federal Court of Appeal also stated:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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[9] National Energy Board. RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital. April 2005. p. 17
[10] *British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al [1960] S.C.R. 837*, at p. 848.

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

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

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

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

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

[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.

[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

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

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

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

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

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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.

[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.

[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

ALBERTA UTILITIES COMMISSION

2018 GENERIC COST OF CAPITAL

PROCEEDING ID #22570

EVIDENCE OF DR. SEAN CLEARY, CFA, BMO PROFESSOR OF FINANCE

Submitted on behalf of:

The Office of the Utilities Consumer Advocate

January 12, 2018

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1. INTRODUCTION

1.1. Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen’s University. I am currently the BMO Professor of Finance at the Smith School of Business at Queen’s University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

I have served as an expert witness on behalf of the Office of the Utilities Consumer Advocate of Alberta (the **“UCA”**) on several occasions including generic cost of capital (“**GCOC**”) proceedings in 2013-2014 (Proceeding ID 2191) and 2015-2016 (Proceeding ID 20622), as well as the generic regulated rate option (“**RRO**”) proceeding (Proceeding ID 2941) in 2014 and the EPCOR Energy Alberta 2018-2021 Energy Price Setting Plan (Proceeding ID 22357) in 2017. I also testified on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, consisting of 30 publications. My work has been cited close to 3,000 times. Most of this work has dealt directly or indirectly with capital markets, capital structure, and cost of equity issues. I have authored or co-authored 13 finance textbooks, all of which deal with capital markets, capital structure, cost of equity, and cost of capital analysis. I examine capital market conditions and estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is attached as Appendix A to my evidence.

1.2. Purpose of Testimony

With respect to the 2018 GCOC Proceeding in Alberta, the UCA has requested that I provide recommendations regarding the appropriate return on equity (“**ROE**”) and equity ratios for Alberta utilities. I acknowledge that I have a duty to provide opinion evidence to the Alberta Utilities Commission (the “**Commission**” or “**AUC**”) that is fair, objective and nonpartisan.

1.3. Summary of ROE Estimates

Section 2 shows that global economic conditions are solid and have improved since the time of the 2016 GCOC Proceeding, and the same can be said of Canadian capital market conditions. Canadian economic growth exceeded expectations during 2017 at an estimated pace of 3% growth in real GDP, while Alberta's 2017 real GDP growth is estimated at 6.7%. Both Canada and Alberta are expected to experience more moderate but solid GDP growth going forward. Bond yield spreads have declined, as has stock market volatility, and both bond and stock markets are healthy. In other words, economic and capital market conditions are solid today, improved since 2016, and far removed from those existing at the peak of the 2008-2009 financial crisis. Regardless, mature, regulated utilities operating in established territories are not influenced by economic cyclicality to the extent of traditional businesses. My evidence confirms this is true for Alberta utilities.

Several approaches were used to estimate the appropriate generic ROE for Alberta utilities including the Capital Asset Pricing Model ("**CAPM**"), Discounted Cash Flow ("**DCF**") and Bond Yield Plus Risk Premium ("**BYPRP**") models. Based on an equal weighting of these three approaches, I estimate the following best estimate and ranges for an appropriate ROE:

Year	CAPM (1/3rd)	DCF (1/3rd)	BYPRP (1/3rd)	Overall Range	Best Estimate
2018 2019	5.5%	6.9%	6.5%	4.0-8.2%	**6.3%**

The details of all estimates are provided herein, as is the reason for choosing an equal weighting scheme.

This estimate is very reasonable when compared to current expectations of market professionals for long-term overall stock market returns in the range of 6-9% (with a best estimate of 7.5%) , when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 6-9% range are consistent with experienced long-term real stock returns of 5.6-7.4%. The ROE estimate is also consistent with our current low interest rate environment, which can be expected to change only gradually over the next few years.

1.4. Summary of Comments on Capital Structure

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility, their ability to generate high operating profit margins, and their ability to grow operating earnings. Given this low risk, it is not surprising that they have been able to generate ROEs above the allowed ROEs for the last 11 years, exceeding the allowed ROE by an annual average (weighted average) of 0.64% (0.97%) over the 2005-2016 period, as I will discuss further below. My analysis also shows that these earned ROEs displayed very low volatility, indicating low total risk.

Combining this risk analysis with my positive economic and capital market outlook, I am recommending no change in allowed equity ratios, but rather emphasize the impetus for a reduction in the allowed ROE. My analysis suggests these recommendations are reasonable, and the credit metric analysis provided by Mr. Bell supports this recommendation.

2. THE ECONOMY AND CAPITAL MARKET CONDITIONS: PAST, PRESENT AND FUTURE

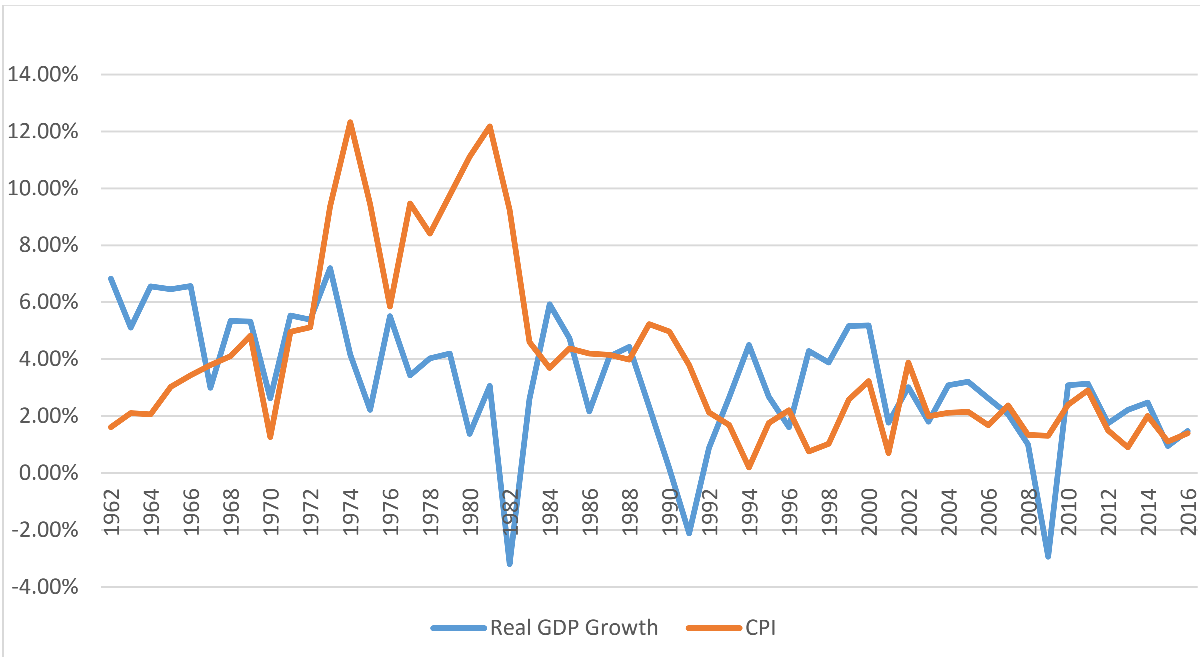
2.1. The Past and Present

2.1.1. Historical Evidence

Figure 1 below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index ("**CPI**") over the 1962 to 2016 period. The graph shows that real GDP growth has generally been in the 2-6% range, with the exceptions of the three recessionary periods that occurred in the early 1980s, the early 1990s, and during our most recent financial crisis. Table 1 reports summary statistics that show the average GDP growth over the entire period was 3.2% (median 3.1%). It is interesting to note that GDP growth declined to an average of 2.5% (median 2.6%) over the 1992 to 2016 period. This represents the period "following" the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from Figure 1, and also as measured by the standard deviation reported in Table 1. The working papers for Figure 1 and Table 1, below, are appended as Exhibit A to my evidence.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2016)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2016)

	1962-2016 (%)		1992-2016 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.21	3.96	2.46	1.81
Median	3.08	3.03	2.62	1.75
Max	7.20	12.33	5.18	3.88
Min	-3.20	0.20	-2.95	0.20
Std Dev.	2.24	3.11	1.66	0.84

Data Source: Statistics Canada.

The 1962-2016 stats are obviously driven by the high rates of inflation during the 1970s and 1980s. Inflation rates have generally been within the Bank of Canada's 1 to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average CPI of 1.81% (median 1.75%). CPI growth has also been very stable during this latter period, which is obvious from Figure 1, and also by the huge decline in standard deviation from 3.1% over the entire 1962-2016 period to 0.8% since 1991. Obviously, forecasting inflation is much easier today than it was in previous years.

2.1.2. Changes since the 2016 Decision

In Decision 20622-D01-2016 (the "**2016 GCOC Decision**"), the Commission stated:

> The Commission's view is that there is no definitive evidence on the record to explain the increased credit spreads, and accordingly it could be the result of a combination of factors. If there is no clear rationale for the increase in credit spreads, then the Commission cannot conclude that the widening of credit spreads indicates increased risk perceptions among Canadian utility bond investors and by extension, Canadian utility equity investors. Equally, the Commission cannot conclude that the widening of credit spreads does not indicate, at least in part, increased risk perceptions among utility bond and equity investors.[1]

The Commission went on to state:

> Based on Figure 5 above and considering the evidence of the parties with respect to market volatility, the Commission considers it reasonable to conclude that recent instability in estimators of investor perceptions of near-term market uncertainty, including the VIX and the VIXC, are indicative of increased investor uncertainty in the 2016-2017 period compared to investor uncertainty which existed at the time of the 2013 GCOC proceeding.[2]

In other words, at the time of its 2016 GCOC Decision, the Commission felt investor uncertainty was slightly elevated relative to 2013 levels. This opinion was based on the possibility (not certainty) that elevated yield spreads indicated elevated risk perceptions, as well as by the higher levels of VIX and VIXC that prevailed in 2016, among other factors.

[1] Decision 20622-D01-2016, 2016 Generic Cost of Capital, page 21, para. 89.
[2] *Ibid.*, para. 91.

It is worth noting that the Commission had noted in Decision 2191-D01-2015 (the "**2013 GCOC Decision**") that:

> All parties agreed that current global economic and Canadian capital market conditions have improved since the time of the 2011 GCOC proceeding resulting in Decision 2011-474. The parties, however, disagreed on the amount of risk remaining in capital markets.[3]

So, in other words, overall, economic and capital market conditions were better during the 2013 GCOC Proceeding than during the previous 2011 GCOC Proceeding and the subsequent 2016 GCOC Proceeding.

During the 2016 GCOC Proceeding, the Consensus Economics Inc. ("**Consensus")** January 2016 forecasts of Canadian GDP growth for 2016 and 2017 were 1.8% and 2.0% respectively, while the Bank of Canada's January 2016 *Monetary Policy Report* ("**MPR**") anticipated slightly lower GDP growth rates at 1.4% and 1.9% for 2016 and 2017. In fact, real GDP growth turned out to be well above these forecasts – at 2.0% in 2016, and at 3.1% in 2017 (as estimated in the Bank of Canada's October 2017 MPR, appended as Exhibit AA to this evidence).

As a result of this strength in the Canadian economy during 2016 and 2017, the Bank increased its overnight lending rate in July 2017 and September 2017, so that it now sits at 1%. These increases essentially reversed the two decreases the bank implemented during the first half of 2015 in response to slower than expected growth. At the other end of the yield curve, Canadian long-term government bond yields increased approximately 50 basis points ("**bp**") in the month following the unexpected election of U.S. President Donald Trump in November 2016 (i.e., from 1.9% to 2.4% by mid-December), and has remained in the 2.0-2.5% range ever since. During November and December 2017, the 30-year Government of Canada yield has generally been in the 2.2-2.3% range, and it sat at 2.19% as of December 19, 2017 – a mere 4 bp above the level at which it ended in 2015 (i.e., 2.15%).

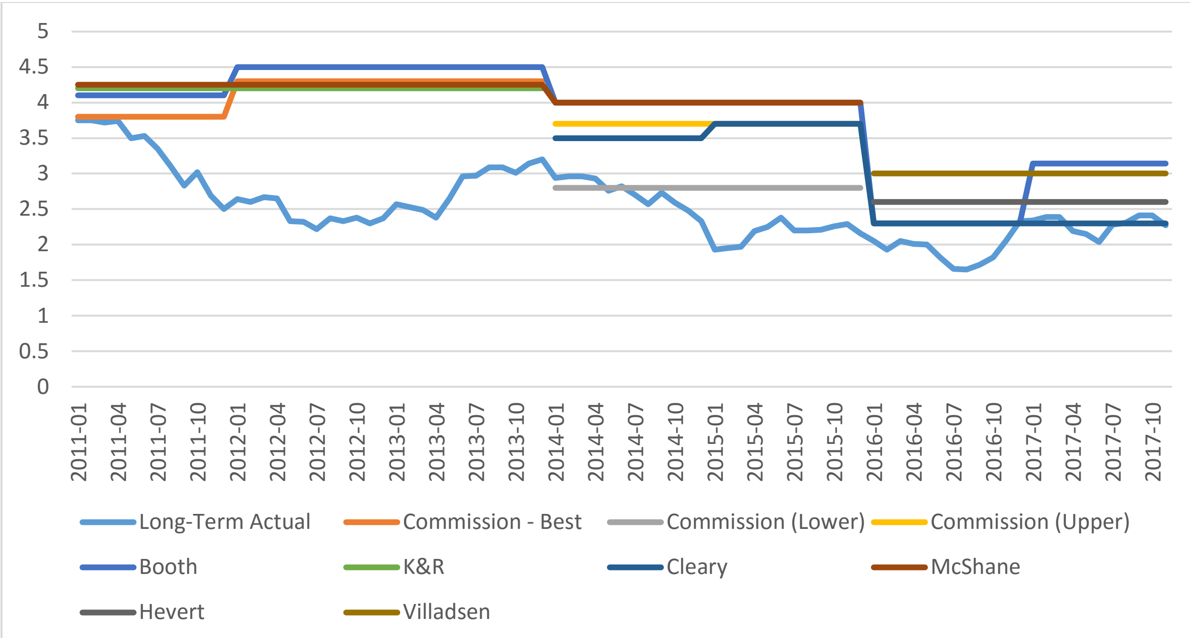
[3] Decision 2191-D01-2015, 2013 Generic Cost of Capital, page 6, para. 37.

During the 2016 GCOC Proceeding, I relied upon the January 2016 Consensus forecasts for government 10-year yields, which were 1.7% for April 2016 and 2.1% for January 2017. I then added the long-term average spread between 10-year and 30-year government yields of 50 bp to arrive at Consensus-based estimates for 30-year government bond yields of 2.2% and 2.6% for April 2016 and January 2017 respectively.[4] Noting that forecasts had consistently been too high in previous decisions, and consistent with the approach used by the Commission in its 2013 GCOC Decision, I used the actual prevailing long-term yield at the time of 2% as a lower bound, and used the 2.6% Consensus-based estimate noted above as my upper bound. I then used the 2.3% mid-point as my base case long-term Canada government bond yield estimate for 2017. This turned out to be very appropriate as the average 30-year government yield from January 1, 2017- November 15, 2017 was 2.29%. No doubt this estimate would have turned out to be too high had it not been for the unexpected election of Donald Trump. This is because my estimate was biased upwards by the influence of Consensus estimates which turned out to be too high, just as they had been during the time periods involved during previous proceedings. This is precisely why it is beneficial to use existing rates as a floor (or ceilings, in the case where Consensus-based forecasts indicate declines from prevailing yields). In other words, forecasters are often wrong, while existing rates offer the benefit of a starting point that reflects actual yields (i.e., yields that investors can actually achieve today), rather than forecasts which may or may not materialize. This is obvious when we look at Figure 2, produced below, which reports the estimates provided by all experts and the Commission in the 2011, 2013 and 2016 GCOC Proceedings, which were all well above the actual long-term government bond yields that materialized, with the exception of my 2016 forecasts which were close. The working papers for Figure 2 are appended as Exhibit B to my evidence.

[4] During the 2016 GCOC Proceeding, the utilities criticized my use of this long-term “average” maturity yield spread rather than the using the existing 76 bp spread at the beginning of 2016. This spread now sits at 26 bp as can be seen later in Figure 9.

FIGURE 2

LONG-TERM CANADA BOND YIELDS VERSUS FORECASTS (2011-2017)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

If we focus on the far right portion of Figure 2, we observe the 2016-2017 actual yields versus the forecast yields. I would note that in the 2016 GCOC Decision, the Commission did not provide a specific forecast that it had relied upon which could be included in Figure 2, but rather it indicated:

> Based on the foregoing, the Commission notes that although the prevailing risk-free interest rate is lower than at the time of the 2013 GCOC decision, general expectations are that interest rates will rise during the 2016-2017 period. Uncertainty remains, however, regarding the speed and magnitude of the expected interest rate increases.[5]

Figure 2 shows that the 2016-2017 forecasts that relied primarily upon Consensus Forecasts in one form or another (i.e., Booth, Hevert and Villadsen) and ignored existing yields were too high. In contrast, my 2016-2017 forecasts were closer to actual results, since they were based on a 50% weighting of prevailing yields in 2016, in addition to Consensus forecasts. Not coincidentally, my forecasts were also much more accurate than my forecasts made

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[5] Decision 20622-D01-2016, 2016 Generic Cost of Capital, page 31, para. 133.

during the 2013 GCOC Proceeding, which relied solely upon Consensus forecasts, and ignored the level of prevailing rates at that time.

During the 2013 GCOC Proceeding, it was noted that yield spreads had declined significantly from their previous abnormal high levels during the 2009 GCOC Proceeding, but remained somewhat elevated at around 140. This spread was noted to be above the long-term average spread of around 100 bp, but well below the peak levels of around 300 bp in 2008-2009. During the 2016 GCOC Proceeding, the utilities' witnesses spent a lot of time discussing the importance of "elevated" yield spreads as an indicator of elevated risks. The A-rated utility spreads were around 200 bps at the time their evidence was prepared in the 2016 GCOC Proceeding; although they had declined to 170 bps by the end of May 2016.

Despite the obvious importance of the total cost of borrowing to utilities, the initial evidence provided by the utilities' experts during the 2016 GCOC Proceeding did not discuss the important fact that the total yields (i.e., their cost of long-term debt) at which the utilities could borrow were actually lower in 2016 than in 2013. Ultimately, the utilities' experts were forced to acknowledge this fact in response to information requests and/or under cross examination. The decline in utility borrowing rates in 2016 was of course due to the decline in government yields, which more than offset the increase in yield spreads. In contrast, I noted this important fact in my evidence in the 2016 GCOC Proceeding:

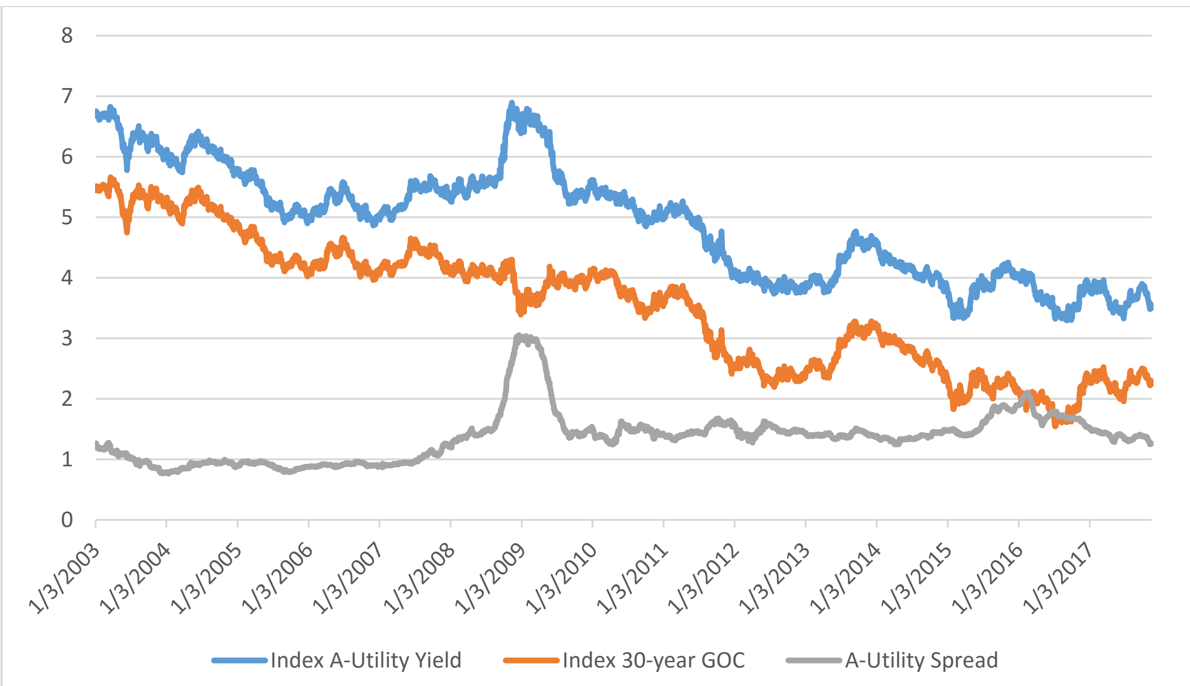
> Despite this increase in yield spreads, the cost of long-term borrowing to A-rated utilities has actually declined since 2013. For example, the average yields were 4.24% and 4.14% during 2013 and 2014, years during which the corresponding yield spreads averaged 1.41% and 1.37% respectively. During 2015, the average yield for A-rated utility bonds was lower at 3.82%, despite a higher average yield spread of 1.63%. While the yield spread had increased to 1.90% by the end of 2015 and to 2.06% by February 3, 2016, the yields on A-rated utility bonds were actually lower than in 2013 and 2014 at 4.05% in December 2015 and 4.03% on February 3, 2016 – of course this is due to the decline in risk-free government bond yields, which form the base rate for utility borrowing.[6]

[6] Exhibit 20622-X0306, Evidence of Dr. Sean Cleary, page 9, lines 4-12.

The opposite offsetting movements in government yields and yield spreads have occurred since the 2016 GCOC Proceeding, which is obvious in Figure 3. In particular, we can see that yield spreads have declined since 2016 (to 1.26% by November 15, 2017), while government yields have increased (to 2.25% by November 15, 2017). The net result of these two changes was a decrease in A-rated Utility bond yields to 3.51%, 52 bp lower than when I prepared my evidence in the 2016 GCOC Proceeding, and 18 bp below the May 30, 2016 level of 3.69%, which was prevailing around the time of the oral hearing in 2016. The working papers for Figure 3 are appended as Exhibit C to my evidence.

FIGURE 3

A-UTILITY YIELDS (January 1, 2003-November 15, 2017)



Source: Bloomberg.

The fact that yield spreads declined and government yields increased as economic and capital market conditions improved is consistent with the argument that I advanced in my evidence in the 2016 GCOC Proceeding:

> It is reasonable to assume that as economic and capital markets gradually return to a more typical state that A-rated utility yield spreads will experience a gradual reduction from their current 2% level to around 1%. This 100 bps decrease would offset to a great extent by the

> expected increase in 10-year (and long-term) government yields of 70 bps during 2016, and another 40 bps in 2017. Of course, if some of the uncertainties identified earlier persist or get worse, these spreads may not return to normal levels, or may do so much slower than expected, so it is not a given. However, under such circumstances, it is unlikely that government yields would increase as much as expected – so changes in government yields and yield spreads tend to go in opposite directions, and offset one another to a certain extent.[7]

In fact, the correlation coefficient between long-term government bond yields and A-rated Utility yield spreads over the January 2003-November 2017 period was -0.49, which indicates a strong negative relationship – exactly as logic would dictate, and as I have argued.

Of course, the evidence of the utilities filed in the current proceeding does not give much attention to this decline in yield spreads (i.e., 80 bp decline since February 2016). Instead, the evidence now focuses on the increase in government yields (i.e., 28 bp since February 2016), which of course has occurred due to improved economic and capital market conditions. In doing so, they are once again ignoring one of the two important components that comprise utility bond yields.

Regardless whether one focuses on yield spreads, on underlying government bond yields, or on both (as should be the case), it is obvious that the cost of long-term borrowing for A-rated Canadian utilities, as measured by long-term bond yields, remains extremely low. This is true in both absolute terms and relative to historical borrowing costs. This implies that the cost of equity for A-rated utilities is also low in both absolute and relative terms, since a company's cost of equity is linked to its cost of debt.[8]

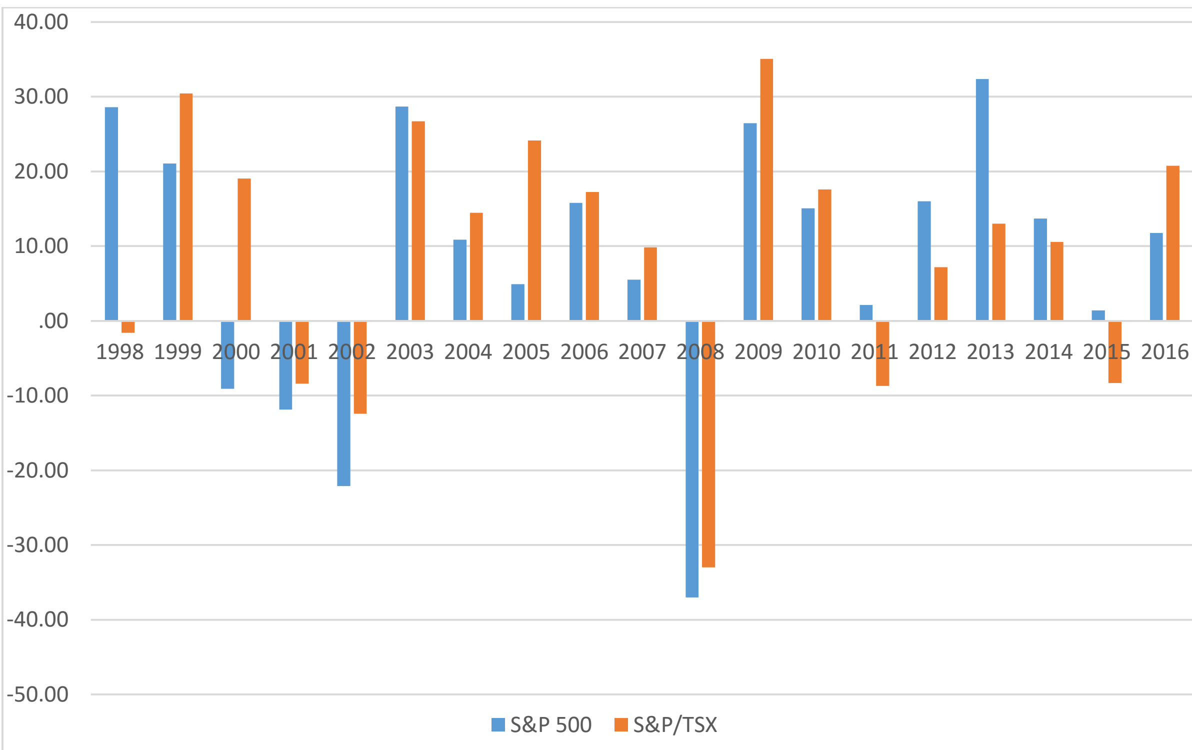
The Canadian stock market had an excellent year in 2016, providing an average total return of 20.8% in 2016, while U.S. markets also had a good year, providing an average return of 11.8%. As of December 20, 2017, the return on U.S. stock markets was 19.7%, while the Canadian market return was 5.7%. Figure 4 provides the average annual total stock returns for Canada and the U.S. over the 1998-2016 period. Over this period, stocks in Canada provided an average return of 9.1% (geometric mean of 7.7%), while U.S. stocks provided an

[7] *Ibid.*, page 27, lines 1-9.
[8] For example, this link is very clear in the widely used BYPRP approach, which will be discussed in detail in Section 3.3.

average return of 8.1% (geometric mean of 6.5%). These figures are low relative to longer term historical nominal averages; however, they are consistent with long-term "real" stock returns in the 6.2% to 7.4% range, and current market expectations (both of which are discussed in Section 2.3.3) that are based on lower inflation expectations over more recent periods, as monetary authorities around the globe have strived to maintain inflation levels in the area of 2%. The working papers for Figure 4 have been appended as Exhibit D to my evidence.

FIGURE 4

STOCK MARKET RETURNS - (1998-2016)



Source: Bloomberg

The trailing price-earnings ("**P/E**") ratio for the S&P/TSX Composite Index stood at 19.6 on November 24, 2017, while the P/E ratio for the U.S. S&P 500 Index was 21.9 on that date. It is common to hear market observers suggest that the stock market is undervalued when P/E ratios fall below 15, or that they are over-valued when they exceed 20, which is the range of long-term average P/E ratios. While this is very simplistic, it does suggest that the current P/E ratios in the 19 to 22 range in Canada and the U.S. are in familiar territory; albeit slightly elevated especially in the case of the U.S. As at November 24, 2017, dividend yields were 1.9% in the U.S. and 2.7% in Canada, also within typical ranges.

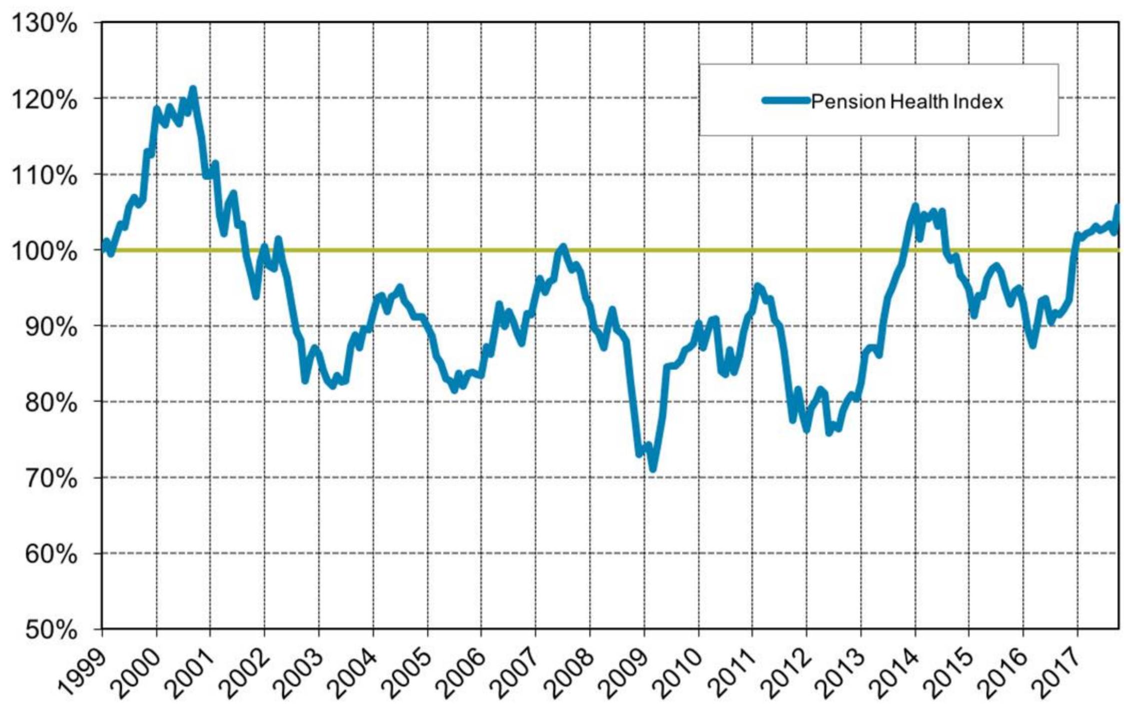
The implied volatility indexes in Canada and the U.S. have averaged in the 16-20 range through time.[9] The Canadian and U.S. VIX indices stood at 10.6 and 9.7 respectively as of December 20, 2017, indicating well below normal volatility in both Canada and the U.S. The current levels are dramatically lower than those that existed at the start of the 2016 GCOC Proceeding and are well below long-term averages. During the 2016 GCOC Proceeding, the utilities' experts stressed that elevated volatility index levels (in the 26 to 40 range) represented a major indicator of elevated levels of risk in equity markets. However, in the current proceeding, the utilities' experts fail to acknowledge that the converse is true – i.e., lower levels could indicate lower levels of risk. Instead, they merely point out that this is a short-term volatility measure.

Finally, pension fund health is a closely watched and important financial health indicator. Poor stock returns during the crisis, combined with extremely low levels of interest rates, hit the funding status of all pension funds. This created concerns that amounted to crises both at the individual and systemic levels. A commonly used measure of overall Canadian pension health is the Mercer Pension Health Index, which tracks the funded status of a hypothetical defined benefit pension plan. Figure 5 depicts the value of this index over the 1999 to 2017 period. The index ended September of 2017 at 106%, up from 102% at the start of 2017, and well above the level of 95% at which it sat in January of 2016, when I prepared my evidence for the 2016 GCOC Proceeding. The continuous improvement since 2016 is a result of increases in long-term bond yields and solid Canadian and U.S. equity market performance. The current level of 106% represents an 11% improvement over the January 2016 level of 95%, is comfortably above 100%, and is well above the all-time low of around 70% in early 2009. Hence, this measure of financial stability indicates improving and solid market conditions, which are better than those existing during the 2016 GCOC Proceeding, and which are nowhere near crisis levels.

[9] According to Mr. Hevert's evidence, the U.S. index has averaged 19.5 since 1990, while the current Canadian index has averaged 16.6 since its inception in 2009.

FIGURE 5

MERCER PENSION HEALTH INDEX - (1999-2017)



Source: https://www.mercer.ca/en/newsroom/defined-benefit-pensions-edge-up-in-q3-2017.html, December 20, 2017.

2.2. The Future

2.2.1. Global Economic Activity

The global economy has faced several challenges since 2008, but is expected to grow at solid rates in 2017 and 2018. For example, Table 2 shows the October 2017 Consensus forecasts for average global real GDP growth figures of 3.1% for both years, while the Bank of Canada's October 2017 MPR estimates were slightly higher at 3.4% for both years. Table 2 shows that the expected global improvements are based in large part on expectations that the U.S. economy will continue to grow steadily over 2017 and 2018 in the 2.2-2.4% range, while the Euro zone will continue to rebound back to more normal growth levels with expected growth rates of 2.2% for 2017 and 1.8% for 2018.

TABLE 2

REAL GDP GROWTH GLOBAL FORECASTS (2017-2018)

Real GDP Growth (%)	2017		2018	
	Consensus	Bank of Canada	Consensus	Bank of Canada
World	3.1	3.4	3.1	3.4
U.S.	2.2	2.2	2.4	2.2
Euro Zone	2.2	2.3	1.8	1.8

Source: Consensus Economics Inc. (October 2017) and Bank of Canada MPR (October 2017).

The Bank of Canada notes several factors contributing to its solid global growth projections in its October 2017 MPR, which is appended as Exhibit AA to this evidence. These factors include: accommodative global financial conditions; moderate growth in the U.S. economy; improving growth in the Euro zone; inflation continuing to track below targets in advanced economies; emerging markets continuing to drive global growth (noting stronger than expected growth in China in particular); and, increases in oil and commodity prices.

2.2.2. Canada's Outlook

The Bank of Canada noted in its October 2017 MPR, appended as Exhibit AA, that Canadian economic growth was rapid during the second quarter of 2017, exceeding expectations. This growth was robust on several levels – across regions, industries, individual consumption, business investment, and export growth. As a result, the Bank estimates that excess capacity declined faster than expected and the Bank estimates the output gap to be between -0.5 to +0.5 percent. This means the economy is operating at or near capacity.

Going forward, the Bank expects solid growth to continue, but at a more moderate and sustainable level. This growth will be supported by several factors, including: rising foreign demand; firming of commodity prices; accommodative monetary and fiscal conditions; improved contributions from exports; and, continued steady business investment. Their growth projections are also reflective of a decline in the contribution to total growth from consumption and residential investment. The Bank notes that its forecast incorporates the most recent increases in the Bank policy rate, as well as the recent appreciation in both the Canadian dollar and commodity prices.

As a result of their analysis, the Bank predicts real GDP growth of 3.1% in 2017, followed by growth rates of 2.1% in 2018 and 1.5% in 2019. Table 3 shows that the 2018 and 2019 forecasts are in line with the Consensus forecasts of 2.0% and 1.9%.

TABLE 3

REAL GDP GROWTH FORECASTS – CANADA (2017-2019)

	2017	2018	2019
Conf. Board of Canada	2.6	1.9	
CIBC World Markets	3.0	2.1	
IHS Economics	3.1	2.3	
Citigroup	3.1	2.1	
BMO Capital Markets	3.1	2.2	
Desjardins	3.1	2.2	
Econ Intell Unit	3.0	1.9	
EconoMap	3.2	2.1	
Oxford Economics	3.0	2.0	
JP Morgan	3.1	1.8	
National Bank	3.0	2.5	
RBC	3.1	2.2	
TD Bank	3.1	2.2	
University of Toronto	2.9	2.1	
Scotia Econ	3.1	2.0	
Informetrica	3.1	2.1	
Inst Fiscal Studies	3.1	2.0	
Capital Economics	3.0	1.5	
Centre for Spatial Economics	2.8	1.9	
Average	**3.0**	**2.0**	**1.9**
Median	**3.1**	**2.1**	
Max	**3.2**	**2.5**	
Min	**2.6**	**1.5**	
IMF (Oct 17)	**3.0**	**2.1**	
OECD (Sept 17)	**3.2**	**2.3**	
Bank of Canada (Oct 2017)	**3.1**	**2.1**	**1.5**

Source: Consensus Economics Inc. (October 2017) and Bank of Canada MPR (October 2017).

Based on the discussion above, the Bank predicts that the economy will operate at close to capacity, but inflation will remain below target at 1.5% in 2017 and 1.7% in 2018, before increasing to 2.1%, slightly above target in 2019. The Bank's projections were slightly below the 2017 and 2018 Consensus forecasts of 1.6% and 1.9%, as well as with those of the IMF (1.6% and 1.8%), all of which can be found in Table 4.

TABLE 4

CPI FORECASTS – CANADA (2017-2018)

	2017	2018
Conf. Board of Canada	1.9	2.0
CIBC World Markets	1.6	2.1
IHS Economics	1.8	2.0
Citigroup	1.7	1.9
BMO Capital Markets	1.5	1.9
Desjardins	1.5	1.8
Econ Intell Unit	1.5	1.8
EconoMap	1.5	1.8
Oxford Economics	1.6	2.1
JP Morgan	1.5	1.9
National Bank	1.6	1.8
RBC	1.5	1.7
TD Bank	1.5	1.7
University of Toronto	1.5	2.1
Scotia Econ	1.5	1.9
Informetrica	1.6	1.9
Inst Fiscal Studies	1.3	1.8
Capital Economics	1.6	1.7
Centre for Spatial Economics	1.7	1.8
Average	**1.6**	**1.9**
Median	**1.6**	**1.9**
Max	**1.9**	**2.1**
Min	**1.5**	**1.6**
IMF (Oct 17)	**1.6**	**1.8**
Bank of Canada (Oct 2017)	**1.5**	**1.7**

Source: Consensus Economics Inc. (October 2017) and Bank of Canada MPR (October 2017).

Of course, there are several uncertainties associated with the projections above. The Bank discussed several key upside and downside risks to their inflation outlook, and suggested that these risks "to the projected path for Canadian inflations are roughly balanced." The noted risks are: (1) a shift toward protectionist trade policies and weaker Canadian exports; (2) a larger impact of structural factors and prolonged excess supply on inflation; (3) stronger real GDP growth in the United States; (4) stronger consumption and rising household debt in Canada; and, (5) a pronounced drop in house prices in overheated markets.

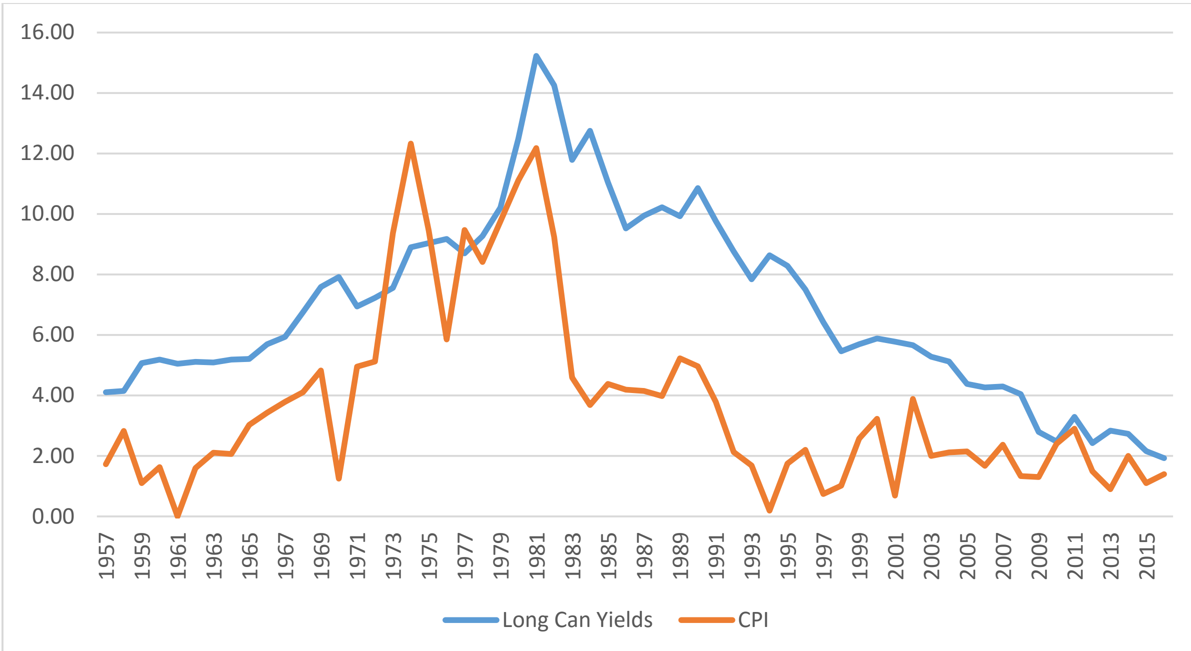
2.3. Capital Market Conditions and Expectations

2.3.1. Debt Markets

What does all this mean for capital markets? I begin by looking at bond yields in particular. Figure 6 shows the relationship between long-term Canada bond yields and inflation since 1957. The graph shows that yields are closely related to inflation. Of course, yields are determined based on "expected" inflation, and we can see a few years in the 1970s where actual inflation exceeded bond yields, since inflation greatly exceeded expectations. The decline in both inflation and yields since 1991 is obvious from the graph, with inflation hovering around the 2% target and bond yields declining and tracking inflation so that by 1998 they were below 6%, where they have remained ever since. It is this part of the graph that we should focus on, since this is representative of our current monetary regime, and during this period, long-term Canada bond yields averaged 4.03%, with inflation averaging 1.92%. Not only have long-term Canada bond yields not exceeded 6% since 1998, they have not exceeded 4.5% since 2005.

FIGURE 6

BOND YIELDS AND INFLATION – CANADA (1957-2016)

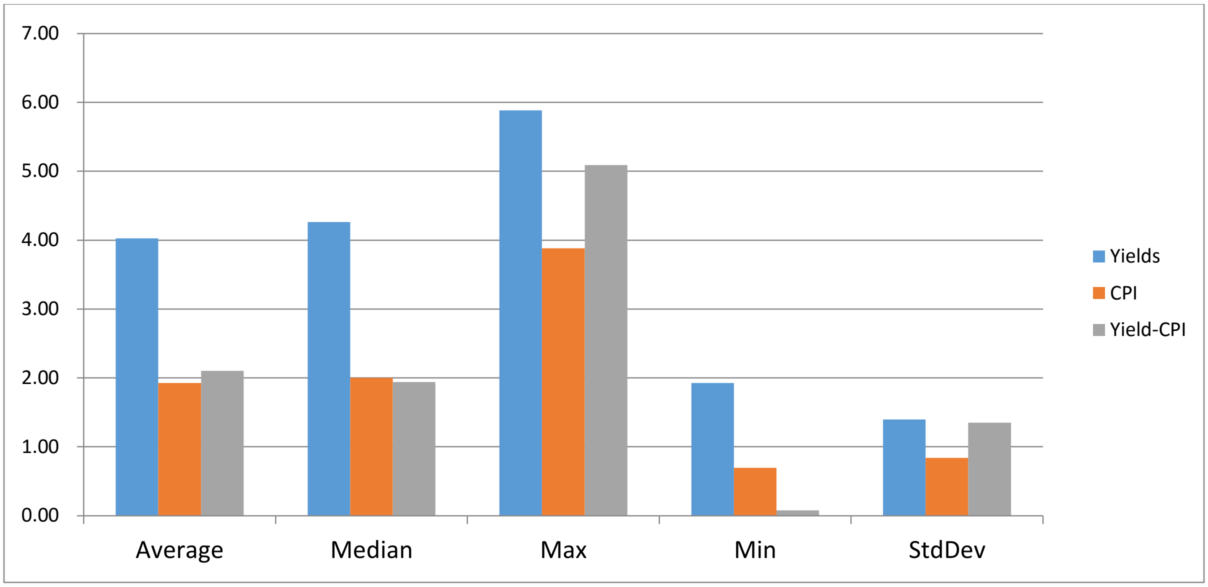


Data Source: CANSIM database.

It is noteworthy that the volatility in yields and inflation has decreased significantly since 1998, which is obvious from Figure 6. This can also be seen in the standard deviations reported in Figure 7, which reports summary statistics for the 1998 to 2016 period. For example, the standard deviation of the yields was 1.39% over this period, versus 3.10% over 1957-2016. Figure 7 also shows that the difference between yields and inflation averaged 2.10% over the period, with a standard deviation of 1.35%. Combining these stats with long-term inflationary expectations of 2% suggests that long-term yields may gravitate towards 4.1% in the long-term, and under average conditions. Clearly, yields remain low today, but they are forecasted to increase, although they are expected to do so at a gradual pace over the next few years, and it may take quite some time to reach 4% levels, if they in fact do. The working papers for Figure 6 and Figure 7 are appended as Exhibit E to my evidence.

FIGURE 7

SUMMARY STATISTICS YIELDS AND INFLATION – CANADA (1998-2016)

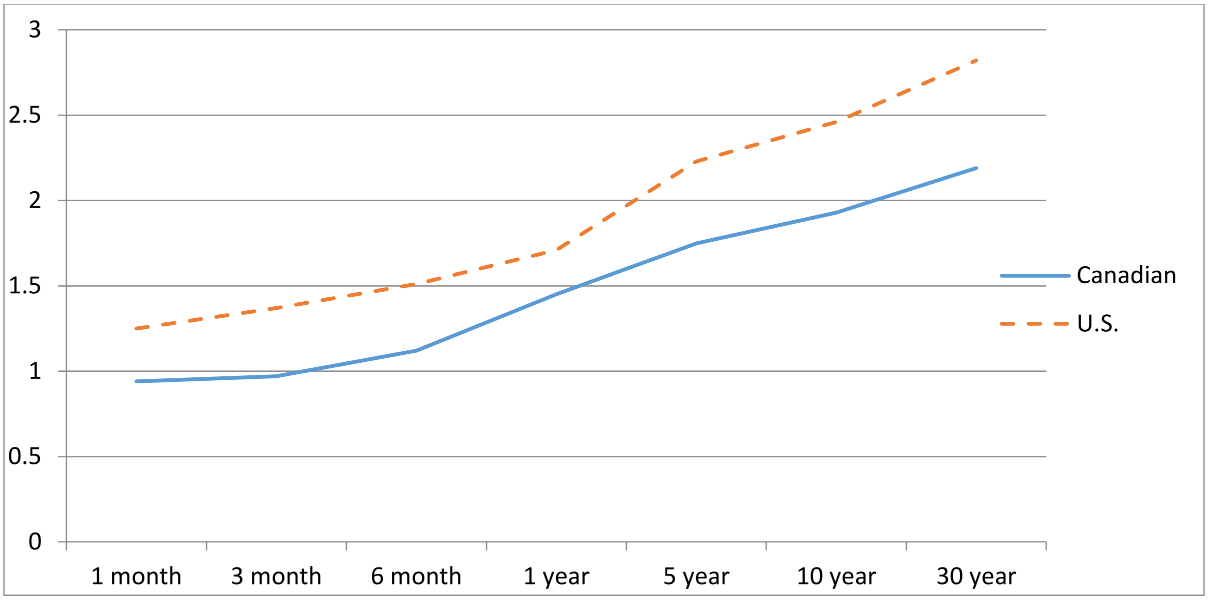


Data Source: CANSIM database.

Figure 8 below depicts the yield curves for Canada and the U.S. as of December 19, 2017. We can see that U.S. rates exceeded Canadian rates across the entire yield curve. For debt that matures within a year, U.S. yields were between 1.2% and 1.7%, while in Canada they were between 0.94% and 1.45%. At the long end of the yield curve, we see 10-year and 30-year U.S. rates of 2.46% and 2.82%, which exceed their Canadian counterparts of 1.93% and 2.19% by 53 bp and 63 bp respectively. According to the 10-year government yield forecasts for Canada and the U.S. from Consensus forecasts (October 2017), the spread between U.S. and Canadian rates are expected to narrow from their current level of 63 bp to 40 bp by October of 2018. The working papers for Figure 8 are appended as Exhibit F to my evidence.

FIGURE 8

YIELD CURVES – CANADA AND THE U.S. (DECEMBER 19, 2017)



Sources: U.S. Data - https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield, December 20, 2017. Canadian data – http://www.pfin.ca/canadianfixedincome/Default.aspx, December 20, 2017.

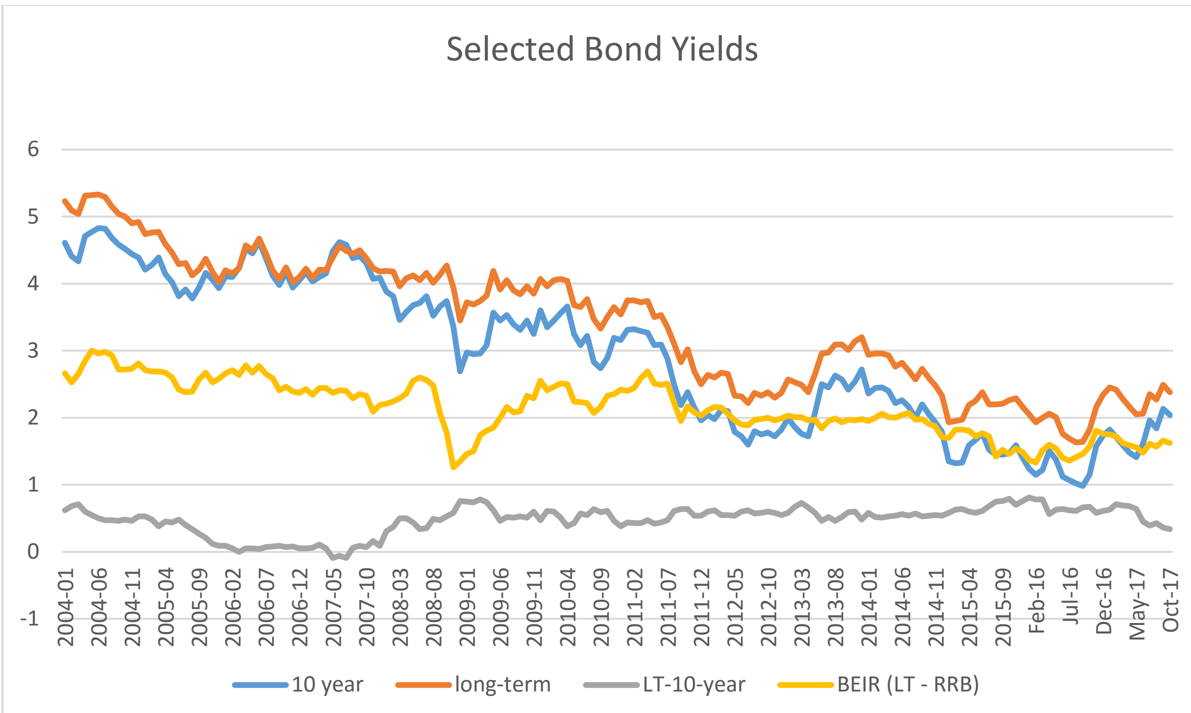
2.3.2. Interest Rate Levels

Figure 9 shows 10-year and long-term bond yields in Canada over the last 14 years, which have moved in tandem for the most part, with a correlation coefficient of 0.99 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.48% (0.53%) over the entire period. It is obvious from Figure 9 that this spread has narrowed considerably during 2017 and sat at 0.34% at the end of October 2017, with long-term rates of 2.38% and 10-year rates of 2.04%, before falling further to 0.26% by December 19, 2017, as long-term rates and 10-year rates fell to 2.19% and 1.93%, respectively, as noted above. Figure 9 also shows the break-even inflation rate ("**BEIR**"), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR is often viewed as an indicator of future inflation rates. This rate remained within the Bank of Canada's target band for inflation over the entire period, peaking at 3.0% in 2004, hitting a trough of 1.26% in November of 2008 around the peak of the crisis, and averaging 2.14% overall, slightly above the Bank's target. It sat at 1.62% at the end of October 2016, a mere 8 basis points below the Bank's CPI forecast for

2018, and 28 basis points below the Consensus CPI forecast. The working papers for Figure 9 are appended as Exhibit G to my evidence.

FIGURE 9

SELECTED BOND YIELDS – CANADA (January 2004-October 2017)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

Considering the discussion above, it is possible that bond yields will increase, albeit slowly, in the coming months, although this is far from a given fact. For example, this represented the consensus view of most economists as of October 2017, as can be seen in Table 5, which reports Consensus forecasts for Government of Canada 10-year bond yields. In particular, the October 2017 Consensus forecasts for 10-year Canada bond yields were 2.3% for the end of January 2018 and 2.5% for the end of October 2018 – representing significant increases from their October 2017 level of 2.04%. Yet, as of December 19, 2017, the 10-year rate had actually decreased 11 bp to 1.93%, a full 37 bp below the January 2018 forecast.

Despite the consistent inaccuracy of Consensus yield forecasts, if we assume the predicted increases occur fairly evenly throughout the year, this implies an average 10-year rate of approximately 2.4% for 2018, with a rate of 2.5% at the start of 2019. Assuming that the long-term average 50 bp spread of 30-year yields over 10-year yields persists throughout 2018, this implies long-term rates would increase from the December 19, 2017 level of 2.19% to an average of 2.9% throughout 2018, and would lie at around 3.0% by January of 2019.[10]

TABLE 5

10-YEAR YIELD FORECASTS – CANADA (2018)

10-Year Canada Yields	**Jan-18**	**Oct-18**
Conf. Board of Canada	2.2	2.6
CIBC World Markets	2.0	2.2
IHS Economics	2.6	3.3
Citigroup	2.4	2.7
BMO Capital Markets	2.3	2.6
Desjardins	2.4	2.9
Econ Intell Unit	2.1	2.5
Oxford Economics	2.1	2.3
EconoMap	2.3	2.5
JP Morgan	NA	NA
National Bank	2.4	2.8
RBC	2.4	2.9
TD Bank	2.1	2.4
University of Toronto	NA	NA
Scotia Bank	2.2	2.5
Informetrica	2.3	2.5
Inst Fiscal Studies	2.1	2.3
Capital Economics	2.5	2.2
Centre for Spatial Economics	NA	NA
Average	**2.3**	**2.5**
Median	**2.3**	**2.5**
Max	**2.6**	**3.3**
Min	**2.0**	**2.1**

Source: Consensus Economics Inc. (October 2017).

As noted in my evidence in the 2016 GCOC Proceeding, reproduced above, it is reasonable to assume that as economic and capital markets continue to improve that A-rated utility yield

[10] Using the prevailing 26 bp spread between 10-year and 30-year yields as of December 20, 2017, would result in Consensus-based long-term yield estimates of 2.66% for 2018 and 2.76% for the start of 2019.

spreads could continue to decline from their current levels of 1.26% (as of November 15, 2017), which would offset to some extent any expected increases in 10-year (and long-term) government yields. Of course, if some of the *uncertainties* identified earlier persist or get worse, these spreads may not return to normal levels, or may do so much slower than expected, so it is not a given. However, under such circumstances, it is unlikely that government yields would increase as much as expected – so changes in government yields and yield spreads tend to go in opposite directions, and offset one another to a certain extent. This is consistent with the observed correlation coefficient of -0.49 between long-term government bond yields and A-rated Utility spreads that was noted previously.

2.3.3. Stock Markets

Predicting stock market performance in the short run is always fraught with uncertainties, and it is always much more productive to think in terms of long run expectations. Table 6 reports summary statistics for Canadian capital markets over the 1938 to 2016 period. The working papers for Table 6 are appended as Exhibit H to my evidence.

TABLE 6

CAPITAL MARKET SUMMARY STATISTICS – (1938-2016)

1938-2016 (%)	CPI	Cdn. Stocks	Long Canadas	T-bills(91-day)	U.S. Stocks (CAD)
Average	3.71	11.14	6.54	4.69	12.76
Median	2.82	11.08	4.26	3.86	12.50
Std. Dev.	3.42	16.44	9.05	4.24	17.36
Geo. Mean	3.65	9.88	6.18	4.61	11.40

Data Source: Data to 2008 are from the Canadian Institute of Actuaries; return data since 2009 are from Bloomberg, while the CPI data are from CANSIM.

The long-term average return in the Canadian stock market over this period was 11.1%, with a geometric mean of 9.9%. This occurred over a period in which inflation averaged 3.7% (geometric mean of 3.65%). This implies “real” returns of approximately 7.4% (6.2%). If we combine these with long-term expected inflation of 2%, we would expect stock returns of 8.2% to 9.4% going forward. These numbers are consistent with, but are higher than, most current estimates of expected stock returns going forward by market professionals, as shown in Table 6 and as discussed in Section 3.1.

2.4. The Alberta Economy

The Conference Board of Canada ("**CB**") 2017 Autumn Provincial Outlook, appended as Exhibit AB to my evidence, estimated that Alberta led the provinces in GDP growth during 2017 at 6.7%. They suggest that this was somewhat surprising and that the strong recovery was driven "largely by rising oil production and a swift turnaround in drilling levels." They also noted the contribution of domestic strength outside the energy sector.

CB does not expect this exceptionally strong growth to continue, but will be followed by more moderate GDP growth rates of 2.1% in 2018 and 1.6% in 2019. The growth will moderate in response to slow growth in energy sector investment and a moderation of the increase in oil production. They do note that recent strength in oil prices may lead to higher than expected drilling rates, which may cause GDP growth to exceed their growth forecasts. So, overall we see a much more optimistic view of the Alberta economy than the one presented during the 2016 GCOC Proceeding.

3. ROE CALCULATIONS

3.1. Capital Asset Pricing Model Estimates

3.1.1. CAPM Overview

This section employs the commonly used CAPM to estimate the allowed ROE for the average regulated Alberta utility. Essentially CAPM can be used to estimate the required ROE (Ke) for a firm from the point of view of a well-diversified investor. It can be presented as:

Ke = RF + (ERm – RF) Beta

Where,

Ke = required rate of return on common equity

RF = the risk-free rate

ERm – RF = the market risk premium or MRP (i.e., expected market return (ERm) minus RF)

Beta = the measure of market risk of a security

This model is widely used:

- by over 68 percent of Financial analysts;[11]
- by over 70 percent of U.S. CFOs;[12]
- by close to 40 percent of Canadian CFOs.[13]

Of course, the CFOs and analysts are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital considerations. It has also been heavily relied upon in previous decisions, which is appropriate in my opinion.

A recent study by Berk and van Binsbergen (2017)[14] also provides support for the use of CAPM as the most widely used model by investors, stating:

> We find that investors adjust for risk by using the beta of the capital asset pricing model (CAPM). Extensions to the CAPM perform poorly, implying that investors do not use these models to compute discount rates.[15]

The authors go on further to highlight the fact that this model should be used by practitioners, despite its limitations, quite simply because it is the most widely used model by investors, who in turn drive equity returns:

> We have demonstrated that among a range of proposed models, the CAPM—though perhaps far from being a perfect model of risk—is most consistent with investor behavior. Thus, if the criterion for deciding how to compute the discount rate is to use the method investors use, **practitioners should use the CAPM**.[16]

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[11] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. This presentation is appended to this evidence as Exhibit AC.
[12] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243. This article is appended to this evidence as Exhibit AD.
[13] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011. This article is appended to this evidence as Exhibit AE.
[14] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32. This article is appended to this evidence as Exhibit AF.
[15] *Ibid.*, page 25.
[16] *Ibid.*, page 32.

3.1.2. Estimating RF

Technically, the CAPM is a one-period model, and the government T-bill rate should be used as the appropriate risk-free rate ("**RF**"), since it is virtually guaranteed and does not fluctuate. However, it is common practice to use the CAPM to estimate the required return on common equity over many periods, such as when trying to estimate the cost of a firm's common equity financing component when estimating the firm's overall cost of capital. Under these circumstances, it is appropriate to use the yield on long-term government bonds instead of T-bills since they are more representative of the rate that could be obtained over longer investment horizons. This practice is consistent with previous decisions.

Similar to the approach I used in the 2016 GCOC Proceeding, which worked very well as discussed previously, I estimate RF using the approach used by the Commission in 2013, as described in paragraph 93 of the2013 GCOC Decision. In particular, the October 2017 Consensus forecasts for government 10-year yields are 2.3% for January 2018 and 2.5% for October 2018. Adding the long-term average spread between 10- and 30-year government yields of 50 basis points to these forecasts, implies forecasted 30-year government bond yields of 2.8% and 3.0% respectively. So 3.0% will provide the upper limit of my RF estimate range. I will round up the actual prevailing long-term government yield of 2.19% as of December 19, 2017 to 2.2%, and use it as my lower bound. This gives me a range of 2.2-3.0% for my 2018-19 RF estimate, with a mid-point of **2.6%**.

3.1.3. Expected Market Returns and Estimating MRPs

The next CAPM input is the Market Risk Premium ("**MRP**"), which is measured by the expected long-term return on the equity market less the long-term government bond yield, which measures RF. Table 7 below provides useful guidance in determining a reasonable estimate for expected stock market returns, which in turn can be used to estimate MRPs, or to assess the reasonableness of MRP estimates. It is broken into three categories: (1) historical returns; (2) current (i.e., 2017) long-term market forecasts from 10 different sources; and, (3) long-term market forecasts from 6 sources that were included in my evidence in the 2016 GCOC Proceeding, and that are more dated. In the 2016 GCOC Decision, the Commission expressed concern regarding the dated nature of some of my cited sources for expected market returns that I referenced in my evidence in the 2016 GCOC Proceeding. Therefore, I do not explicitly attach any weight to the estimates provided from those 6 sources that I previously referenced. I include these sources in Table 7 to illustrate a point – these estimates are in line with today's forecasts. This is to be expected, since they are *long-term* forecasts, and since *long-term* market prospects have not changed materially over the last 5 years or so.

Despite the objections by the utilities, the Commission noted these forecasts are informative, stating:

> In the 2013 GCOC decision, the Commission confirmed its view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities. The Commission **continues to hold this view** and agrees with Dr. Booth's assessment that **these reports are informative**, since these types of reports are circulated in the investment community, although they may be used for different reasons. Therefore, **the Commission will consider return expectations of finance market professionals in arriving at an allowed ROE value**. The Commission is not indicating a preference for one type of report versus another. The reports and any potential perceived biases in those reports will be evaluated on their merits.[17]

Hence, the Commission believes that such information is relevant, and I agree. In fact, I would argue that the beliefs of professionals who participate in the markets and influence market activity is far more relevant than market expectations determined using unrealistic assumptions, such as those provided by the utilities' experts. In other words, market participant beliefs represent an important and practical "benchmark," against which any utility ROE estimate must be compared. Table 7 provides Canadian, U.S. and global evidence; however, since I estimate CAPM using the Canadian stock market, I focus my discussion on the Canadian evidence.

[17] Decision 20622-D01-2016, 2016 GCOC Decision, page 64, para. 296 [footnotes omitted] [emphasis added].

TABLE 7

HISTORICAL AND FORECAST EQUITY RETURNS

Source	Horizon	Canada	U.S.	World / Developed Markets (excl. U.S.)
HISTORICAL RETURNS				
1. Table 6 (Cleary evidence)	Historical: 1938-2016	Real: 6.2% GA 7.4% AA		
2. Dimson, E., P. Marsh, and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[18]	Historical: 1900-2015	Real: 5.6% GA 7.0% AA	Real: 6.4% GA 8.3% AA	Real (World Excl U.S.): 4.3% GA 6.0% AA
3. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017. Source: https://www.calpers.ca.gov/docs/board-agendas/201701/day1/3.3-2018-alm_presentation-2-mckinsey.pdf [19]	Historical: 1915-2014		Real: 6.5%	
Average (Range)		**Real: 6.55% (5.6%-7.4%)**	**Real: 7.07% (6.4%-8.3%)**	**Real: 5.15% (4.3%-6.0%)**
FORECAST RETURNS				
4. Financial Planning Standards Council and Institut Quebecois de planification financiere as cited in: "Investors need to be ruthlessly pessimistic about their returns," R. Carrick, Globe and Mail, Report on Business, August 10, 2017, B7.[20]	Long-term forecast	Nominal: 6.5%		
5. "Capital Market Assumptions (as of March 31, 2017)," AON Hewitt.[21] Source: http://www.aon.com/attachments/human-capital-consulting/capital-market-assumptions-2017-q1.pdf	10-year forecast	Nominal: 6.3%	Nominal: 6.5%	
6. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017.[22] Source: https://www.calpers.ca.gov/docs/board-agendas/201701/day1/3.3-2018-alm_presentation-2-mckinsey.pdf	20 year forecast		Real: 4.0 to 6.5% (Adjust by 2% to Nominal: 6.0-8.5%)	

[18] Appended to this evidence as Exhibit AG.
[19] Appended to this evidence at Exhibit AH.
[20] Appended to this evidence as Exhibit AI.
[21] Appended to this evidence as Exhibit AJ.
[22] Appended to this evidence at Exhibit AH.

7. "2017 Long-Term Capital Market Expectations," Franklin and Templeton Investments, February 2017.[23] Source: http://www.franklintempleton.co.uk/downloadsServlet?docid=iyhcbe3v	7-year forecast	Nominal: 8.1%	Nominal: 7.3%	Nominal: Global 7.8% Developed 7.5%
8. "Perspectives: For the Period Beginning April 1, 2017," CIBC Asset Management, March 2017.[24] Source: https://www.cibc.com/ca/asset-management/pdf/news-publications/newsletters/perspectives/perspectives-period-beg-mar2017-en.pdf	10-year forecast	Nominal: 4.0%	Nominal: 1.9%	Nominal: World 3.8%
9. "2017 Long-Term Capital Market Assumptions," J.P. Morgan Asset Management, 2017.[25]	10-15 year forecast		Nominal: 6.25%	
10. "Strategic Perspectives: Capital Market Assumptions and a Toolkit for Asset Allocation," BlackRock, May 2017[26]	10-year forecast	Nominal: 4.3%		Nominal: World excl. Can. 5.8%
11. "Alternative Thinking," AQR Capital Management LLC, First Quarter 2017. [27]	10-year forecast	Real: 3.8% (Adjust by 2% to Nominal: 5.8%)	Real: 4.2% (Adjust by 2% to Nominal: 6.2%)	Real: World (Developed) 4.4% (Adjust by 2.5% to Nominal: 6.9%)
12. "Callan's 2017-2016 Capital Market Projections," Callan Institute, January 2017.[28]	10-year forecast		Nominal: 6.85%	Nominal: World excl. U.S. 7.0%
13. "Long-Term Capital Market Assumptions," Voya Investment Management, February 2017[29]	10-year forecast		Nominal: 7%	
Average (Range)		**Nominal 5.83% (4.3%-8.1%)**	**Nominal 5.28% (1.9%-8.5%)**	**Nominal 6.26% (3.8%-7.8%)**
FORECAST RETURNS (from Evidence in the 2016 GCOC Proceeding)				
14. Financial Planning Standards Council and Institut Quebecois de planification financiere as cited in: "A more realistic take on projected returns," R. Carrick, Globe and Mail, Report on Business, May 23, 2015, B10.[30]	Long-term forecast	Nominal: 6.5%		

[23] Appended to this evidence at Exhibit AK.
[24] Appended to this evidence at Exhibit AL.
[25] Appended to this evidence as Exhibit AM.
[26] Appended to this evidence as Exhibit AN.
[27] Appended to this evidence as Exhibit AO.
[28] Appended to this evidence as Exhibit AP.
[29] Appended to this evidence as Exhibit AQ.
[30] Appended to this evidence as Exhibit AS.

15. "AON Hewitt Capital Market Assumptions & Methodology (Canadian Version)," Aon Hewitt, January 7, 2016.[31]	10-year forecast	Nominal: 8.3% AA 7.1% GA		
16. "Calculating investment returns: Actuarially speaking 6% is a good rule of thumb," Fred Vettese, http://business.financialpost.com/2013/09/21/calculating-investment-returns-actuarially-speaking-6-is-a-good-rule-of-thumb/, January 24, 2014.	Long-term forecast	Real: 5.25% (Adjust by 2% to Nominal: 7.25%)		
17. "Determination of Best Estimate Assumptions for Investment Return (PPICP)," Educational Note, Canadian Institute of Actuaries, Document 212106, December 2012.[32]	Long-term forecast	Nominal: 7%		
18. "Long-Term Returns: A Reality Check for Pension Funds and Retirement Savings," R. Guay and L.A. Jean, Commentary No. 395, C.D. Howe Institute, December 2013.[33]	Long-term forecast	Nominal: 6.9%		
19. "Estimating Equity Returns," Victor Modugno, Sponsored by Society of Actuaries' Pension Section Research Committee, Society of Actuaries, October 2012.[34]	Long-term forecast	Nominal: 6.3%		
Average (Range)		**Nominal 7.18% (6.5%-8.3%)**	**Nominal 6.3%**	

The first three sources in Table 7 provide historical long-term real returns for Canadian, U.S. and global stock returns over three extremely long time periods (i.e., 79 years, 116 years and 100 years). The Canadian evidence suggests average real returns of 6.55%, with a range of estimates of 5.6% to 7.4%. Combining these figures with 2% expected inflation would suggest expected nominal returns of 8.55%, ranging from 7.6% to 9.4%, based solely on historical results. The next 10 sources represent 2017 estimated long-term market returns from a number of reputable sources with various mandates (i.e., the Financial Planning Standards Council; consulting firms such as AON Hewitt and McKinsey; and, several investment management firms such as CIBC Asset Management, BlackRock, etc.). Since most of the estimates are provided in nominal terms, I adjust those made in real terms to corresponding nominal terms by adding 2% expected inflation. The Canadian market nominal estimates range from 4.0% to 8.1%, and average 5.83%. Deducting the 2% expected

[31] An excerpt is appended to this evidence as Exhibit AZ.
[32] Appended to this evidence as Exhibit AU.
[33] Appended to this evidence as Exhibit AV.
[34] Appended to this evidence as Exhibit AW.

inflation, this translates to an average *real* return of 3.83%. In other words, most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term *real* rates of return in the 5.6-7.4% range over the next 5-10 years, with most of them citing the current low interest rate environment as one of the main contributing factors.

I believe that both historical returns and current expectations of market professionals represent the best sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table 7 and discussed above, suggests a range of estimates in the 4.0% to 9.4% range. In my evidence in the 2016 GCOC Proceeding, I suggested a range of 7-9% made sense, and that a mid-point of 8% seemed like a reasonable best estimate. Having gathered much more information regarding market professionals' opinions for the purposes of the current proceeding, as well as having conducted numerous subsequent conversations with finance professionals on the topic, I am now convinced that 8% is in fact a somewhat optimistic estimate; although possible. As a result, I now believe that a more appropriate range for expected long-term Canadian stock market returns is 6-9%, and the mid-point of 7.5% represents a better point estimate. Not coincidentally, it is also consistent with my choice of MRP of 5%, discussed below, and my RF estimate of 2.6%, as discussed above.

There was much discussion during the 2016 GCOC Proceeding regarding the informativeness of the beliefs or forecasts of market professionals. Not surprisingly, the utilities' experts argued then, as they do now, that such beliefs are not relevant, just as they similarly implicitly ignored the historical evidence regarding long-term real returns earned in the stock markets. This is because both historical evidence and the beliefs of market professionals provide overwhelming evidence that contradicts the utilities' experts' expected market return estimates. For example, in the current proceeding, the expected Canadian stock market return forecasts provided by the utilities' experts fall within the range of 12.7% to 15.6%.[35] These estimates indicate real returns that are somewhere between 14%-79% higher

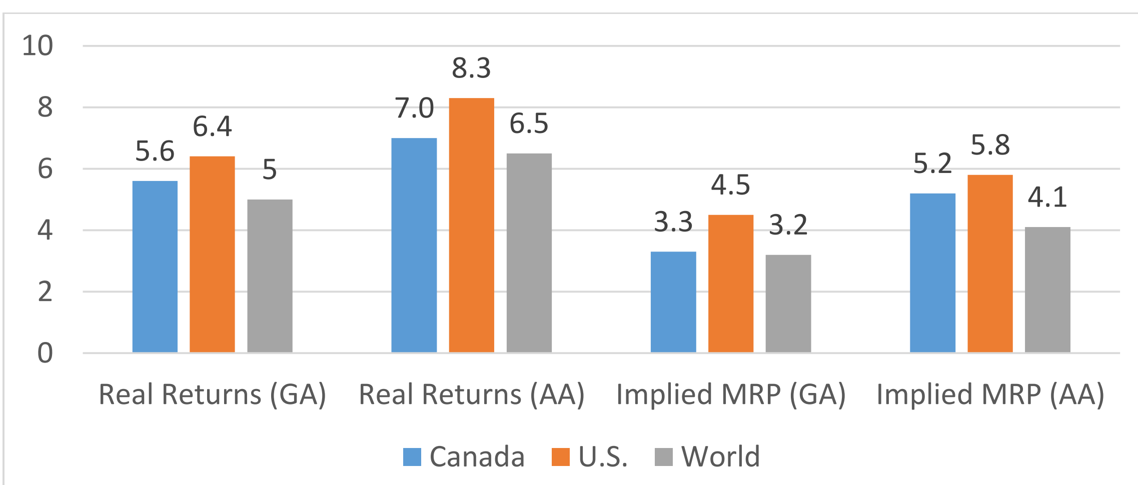
[35] These figures are based in large part upon MRP estimates derived for a market index (i.e., S&P/TSX Index or S&P 500 Index) that are determined using the single-stage dividend discount model (DDM) combined with analyst estimates that exceed expected nominal GDP growth. Hence, the constant growth rates employed by the violate one of the conditions used by the Commission in previous decisions to reject such single stage DDM estimates. I will discuss this flawed approach to estimating MRPs in greater detail later in my evidence.

than average long-term real returns between 5.6%-7.4%. The nominal estimates noted above are even more out of touch with current expectations of market participants, being 57%-263% above current finance professionals' forecasts of Canadian long-term stock market returns reported in Table 7, which ranged from 4.3% to 8.1%. In my view, these are unrealistically high market forecasts which do not reflect the views of finance practitioners.

Figure 10 shows that the world market MRP, as measured by the return on the market less the long-term government bond yield over the 1900-to-2015 period, provided an arithmetic average of 4.1% (geometric mean of 3.2%). These means are lower than the corresponding U.S. (5.8% and 4.5%) and Canadian (5.2% and 3.3%) figures over that period. The figures for Canada are in line with the differences between the average (and geometric mean) returns for stock and bond returns over the 1957 to 2016 period, which were 4.6% (3.7%) as previously reported in Table 6. These numbers are also consistent with expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6% range for most regions. The results for Canada and the U.S. are reported in Figure 11.

FIGURE 10

CANADA, U.S. AND GLOBAL MARKET RISK PREMIUMS (1900-2015)

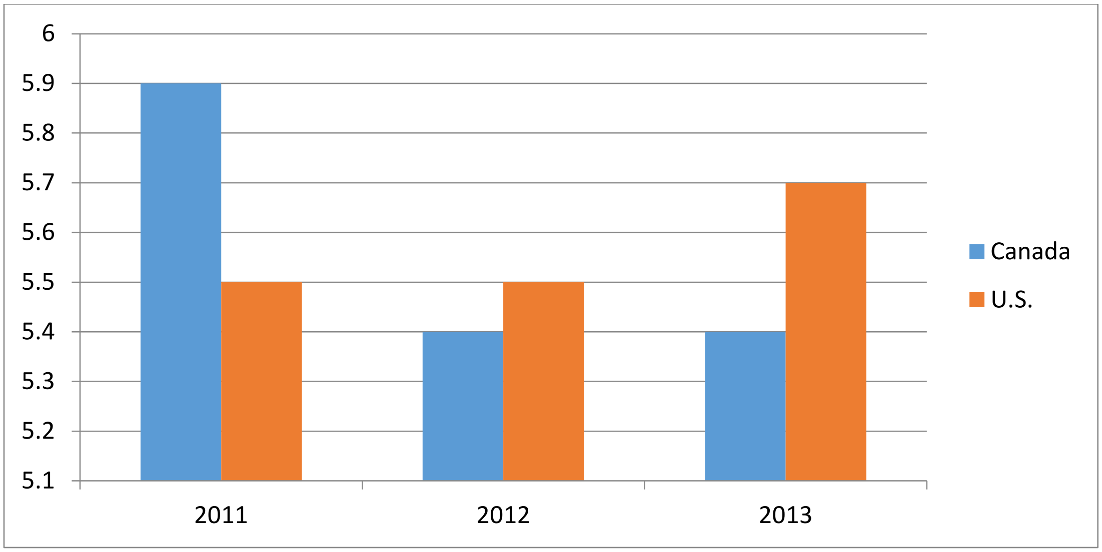


Source: Dimson, E., Marsh, P. and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[36]

[36] Appended as Exhibit AG.

FIGURE 11

CANADA AND U.S. MARKET RISK PREMIUM ESTIMATES (2011-2013)



Source: "Market Risk Premium and Risk Free Rate used for 51 countries in 2013: a survey with 6,237 answers," 2013, by Pablo Fernandez, Javier Aguirreamalloa, and Pablo Linares, Working Paper, IESE Business School.[37]

Based on the previous discussion of capital markets, I concluded that stock markets reflect fairly normal conditions, but are experiencing below average volatility, which is lower than at the time of the oral hearings in both the 2016 GCOC Proceeding and the 2013 GCOC Proceeding. Therefore, I use an **MRP of 5%**, which is the mid-point of the commonly used 4-6% range, 20 bp below the long-term average Canadian MRP of 5.2%, and 170 bp above the long-term geometric mean MRP of 3.3%. This seems appropriate in today's environment, where economic and market conditions are fairly normal in terms of valuation metrics like P/E ratios and dividend yield measures, but market volatility is below average. This is consistent with the practice of using 6%when market uncertainty is above average, using 5%when markets are normal, and using 4% during periods of extreme market and economic optimism. These estimates are also consistent with previous decisions by the AUC. For

[37] Appended as Exhibit AT.

example, the AUC used an MRP range of 5-7% in the 2013 GCOC Decision[38] and 5.0-7.25% in Decision 2011-474 (the "**2011 GCOC Decision**").[39].

I know from having read numerous investment reports and from having seen numerous presentations from finance professionals that it is common practice to use a range of 3-7% for the MRP when using the CAPM to estimate required returns of equity for firms, with the large majority of MRP estimates falling in the 4-6% range. In fact, it is so common, that it is almost assumed.. Similarly, it has also always been the case that the MRP would be adjusted upwards during higher periods of uncertainty, and downwards during periods of less uncertainty. I provide some strong evidence below regarding MRPs which is included in two research articles written by prominent finance professors.

In a 2013 working paper, Aswath Damodaran discusses MRP estimation (which he refers to as the equity risk premium (ERP)).[40] In this paper, Dr. Damodaran discusses the results of Merrill Lynch from its monthly surveys of global institutional investors evidence:

> Merrill Lynch, in its monthly survey of institutional investors globally, explicitly poses the question about equity risk premiums to these investors. In its February 2007 report, for instance, Merrill reported an average equity risk premium of 3.5% from the survey, but that number jumped to 4.1% by March, after a market downturn. As markets settled down in 2009, the survey premium has also settled back to 3.76% in January 2010. Through much of 2010, the survey premium stayed in a tight range (3.85% - 3.90%) but the premium climbed to 4.08% in the January 2012 update.[41]

This evidence verifies that finance professionals believe that MRPs lie within the 3-6% range (or, more aptly, the 3-4.5% range), and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

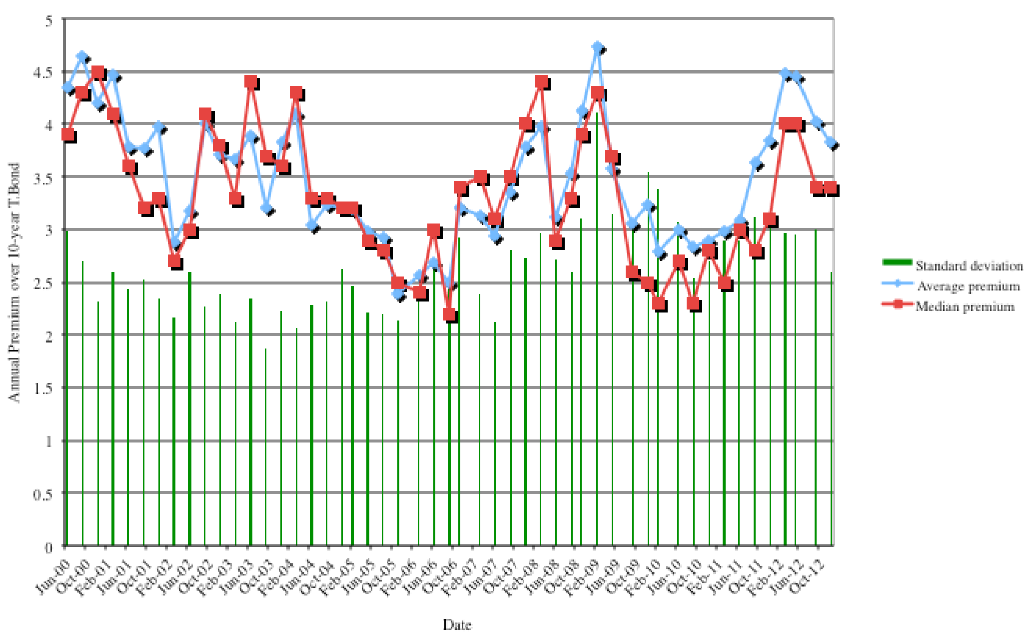
Dr. Damodaran then proceeds to discuss the results of Graham and Harvey (2013)'s surveys

[38] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 115.
[39] Decision 2011-474, 2011 Generic Cost of Capital, para. 59.
[40] Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2013 Edition," Aswath Damodaran, Stern School of Business, New York University. This article is appended as Exhibit AX to this evidence.
[41] *Ibid.,* pages 18-19.

of CFOs regarding MRPs:

> To get a sense of how these assessed equity risk premiums have behaved over time, we have graphed the average and median values of the premium and the cross sectional standard deviation in the estimates in each CFO survey, from 2001 to 2012, in Figure 2.

Figure 2: CFO Survey Premiums



> Note the survey premium peak was in February 2009, right after the crisis, at 4.74% and had its lowest recording (2.47%) in September 2006. The average across all 13 years of surveys (about 9000 responses) was 3.53%.[42]

This evidence also verifies that finance professionals believe that MRPs lie within the 3-6% range (or , more aptly, in the 2.47-4.74% range) over the 2000-2012 period, and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

Dr. Damodaran also discusses the implied MRPs in the S&P 500 Index from 1960-2012 and produces Figure 9, below:[43]

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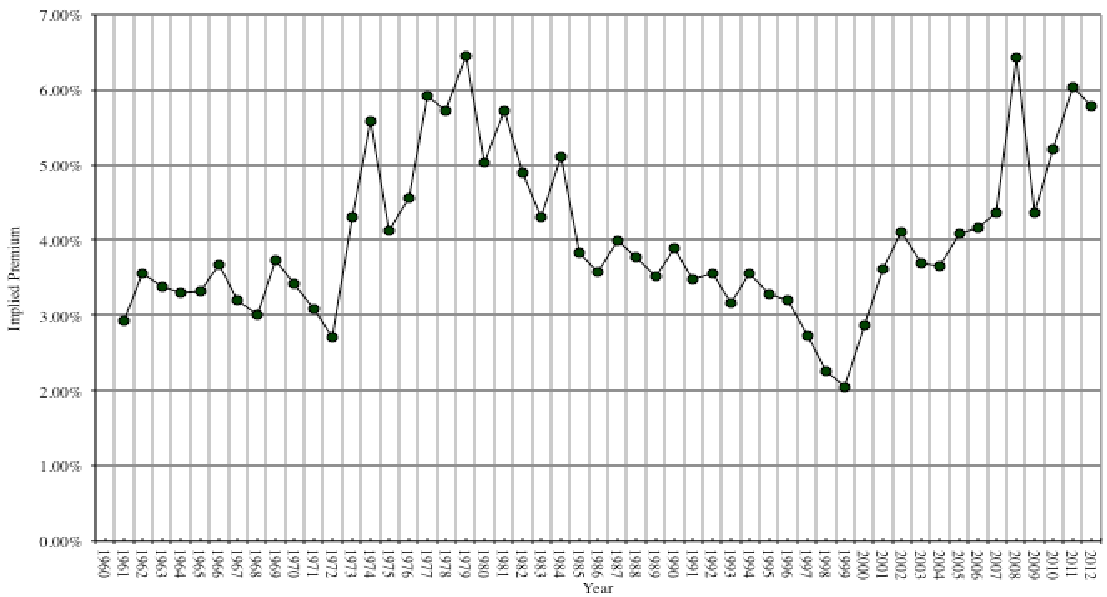
[42] *Ibid.*, pages 20-21.
[43] *Ibid.*, page 74.

Figure 9: Implied Premium for US Equity Market



This evidence also shows that implied MRPs generally lie within the 3-6% range (and in fact are never less than 2% or above 6.5%), and that the MRP increases during periods of uncertainty (e.g., 1979 and 2008), and declines during periods of less uncertainty (e.g., the boom in stock markets at the end of the 1990s).

Dr. Damodaran discusses his own approach to estimating and using MRPs when valuing companies, stating:

> On a personal note, I believe that the very act of valuing companies requires taking a stand on the appropriate equity risk premium to use. For many years prior to September 2008, I used 4% as my mature market equity risk premium when valuing companies, and assumed that mean reversion to this number (the average implied premium over time) would occur quickly and deviations from the number would be small. Though mean reversion is a powerful force, I think that the banking and financial crisis of 2008 has created a new reality, i.e., that equity risk premiums can change quickly and by large amounts even in mature equity markets. Consequently, I have forsaken my practice of staying with a fixed equity risk premium for mature markets, and I now vary it year-to-year, and even on an intra-year basis, if conditions warrant. After the crisis, in the first half of 2009, I used equity risk premiums of 6% for mature markets in my valuations. As risk premiums came down in 2009, I moved back to using a 4.5% equity risk premium for mature markets in 2010. With the increase in implied

> premiums at the start of 2011, my valuations for the year were based upon an equity risk premium of 5% for mature markets and I increased that number to 6% for 2012. In 2013, I will be using a slightly lower equity risk premium (5.80%), reflecting the drop from 2012.[44]

This evidence verifies that a well-respected finance professional, textbook author, and provider of financial data uses MRPs in the 4-6% range and varies his choice of MRP so that it increases during periods of uncertainty, and declines during periods of less uncertainty.

The results of a 2013 survey by Graham and Harvey was discussed above by Dr. Damodaran.[45] I would also note the following conclusions Dr. Graham and Dr. Harvey reached based on their ongoing surveys of CFOs:

> the CFOs believe that the "risk premium" is a longer-term measure of expected excess returns and best covered by our question on the expected excess return over the next ten years – rather than the one-year question. Three-fourths of the interviewees use a form of the Capital Asset Pricing Model (which is consistent with the evidence in Graham and Harvey, 2001). They use a measure of the risk premium in their implementation of the CAPM.[46]

These conclusions are consistent with the long-term (with adjustments) approach to estimating the MRP that I advocate. It also shows that 3/4ths of CFOs use some version of the CAPM.

Further, Dr. Graham and Dr. Harvey examine the relationship between MRPs and two other common measures of risk aversion that I have referenced previously – the VIX and yield spreads:

> Finally, we consider two measures of risk and the risk premium. Figure 5 shows that over our sample there is evidence of a strong positive correlation between market volatility and the long-term risk premium. We use a five-day moving average of the implied volatility on the S&P index option (VIX) as our volatility proxy. The correlation between the risk premium and volatility is 0.52. If the closing day of the survey is used, the correlation is roughly the

[44] *Ibid.*, page 79.
[45] "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. This survey is appended to this evidence as Exhibit AY.
[46] *Ibid.*, page 8.

> same. Asset pricing theory suggests that there is a positive relation between risk and expected return. While our volatility proxy doesn't match the horizon of the risk premium, the evidence, nevertheless, is suggestive of a positive relation. Figure 5 also highlights a strong recent divergence between the risk premium and the VIX.
>
> We also consider an alternative risk measure, the credit spread. We look at the correlation between Moody's Baa rated bond yields less the 10-year Treasury bond yield and the risk premium. Figure 6 shows a highly significant relation between the time-series with a correlation of 0.54.[47]

This evidence confirms that MRPs tend to increase as risk aversion increases, and decrease as risk aversion declines, which is consistent with my approach to estimating MRPs.

In sharp contrast to the approach that I use in determining a reasonable MRP, and contrary to historical evidence, as well as the estimates provided by market professionals, the utilities' experts arrive at Canadian MRP estimates of 8% (Villadsen), 9.38% (Coyne) and 11.90-12.53% (Hevert). All of these estimates are unrealistic and far exceed the upper bound suggested by historical evidence and those estimated by the finance community. When combined with their inflated estimates of RF (3.3% - Villadsen; 3.26% - Coyne; and, 2.38%-3.08% - Hevert), they obtain expected Canadian equity market returns of 11.3%, 11.76% and 13.18%-14.71% respectively. As I demonstrate, all of these estimates are unrealistic.

Mr. Hevert and Mr. Coyne both estimate their MRPs using single-stage Dividend Discount Model ("**DDM**") estimates for the S&P/TSX Index based upon analyst estimates of growth rates that far exceed expected GDP growth. This violates the findings of the Commission in terms of allowable growth rates that can be used in the constant-growth version of the DDM.[48] The use of this model across a broad number of firms in different industries and of various sizes and stages of development is faulty to begin with, since it implies that all firms used to estimate the MRP pay dividends that can be expected to grow at a constant annual rate to infinity. The flaw in this approach, particularly for the S&P/TSX Index, is obvious if we note that 34 (Hevert) to 58 (Coyne) of the 250 companies included in the TSX Index did

[47] *Ibid.*, pages 14-15.
[48] Decision 20622-D01-2016, 2016 Generic Cost of Capital Decision, para. 287.

not have a valid dividend yield, which suggests they do not pay dividends. An additional 143 (Hevert) to 149 (Coyne) firms in the TSX Index did not have valid earnings growth estimates available. As a result, Mr. Hevert and Mr. Coyne estimated the MERP for the TSX Index using only 88 and 79 firms respectively. Of far greater concern is the fact that the average *long-term growth rates* used to estimate the Canadian MRPs were unrealistically high at 13.08% (Hevert) and 11.99% (Coyne) – in strong violation of the Commission's requirement that such long-term growth rates should not exceed expected nominal GDP growth of about 4%. This is an attempt to include equity estimates based on unrealistically high, and inadmissible, growth rates. In addition, the MRPs are estimated using the *actual* prevailing long-term government bond yields; however, the experts then proceed to use these unrealistic MRPs in combination with measures of RF that are based on *expectations* of forecasted higher bond yields, rather than using today's yield – which further inflates their CAPM estimates. Clearly, these MRP estimates should be disregarded, since they are uninformative.

Dr. Villadsen uses estimates that she claims are provided by Bloomberg that indicate a Canadian MRP of just below 10%, which she combines with her Bloomberg U.S. MRP estimate of 7.3% to arrive at a Canadian MRP estimate of 8%. In response to Villadsen-UCA-2017NOV21-007,[49] Dr. Villadsen simply provided screenshots from Bloomberg, which fail to provide sufficient detail to determine precisely how Bloomberg estimates these MRPs. However, what is provided suggests that the Bloomberg estimates are based on the constant-growth version of the DDM which uses analyst growth estimates as the perpetual long-term growth rate. Therefore, in all likelihood, these MRP estimates suffer from the same limitations as those of Mr. Hevert and Mr. Coyne. As a result, these MRP estimates are also not meaningful.

3.1.4. Estimating Beta

We now require a beta estimate to apply the CAPM. Appendix B includes my recommendations to the Commission that will avoid the issue of having to consider such a wide range of expert beta estimates, such that the range provides little guidance. Appendix B

[49] Exhibit 22570-X0428, Information Response to UCA-2017NOV21-007.

provides an examination of historical evidence provided by three of the utilities' experts that confirm the following three points:

1. Canadian utility beta estimates over the last 22-25 years have averaged somewhere between 0.20 and 0.40 – with 0.35 representing the best estimate.
2. Canadian utility beta estimates have never come close to one, with maximum values in the 0.6-0.8 range. Neither have U.S. utility beta estimates ever come close to one for that matter. Hence the use of traditional adjusted betas is totally inappropriate.
3. U.S. utility beta estimates are significantly higher than those for Canadian utilities, and should not be considered.[50] This is consistent with the higher level of business risk associated with U.S. utilities.

Based on these observations, I made the following recommendations to the Commission in terms of determining reasonable beta estimates:

1. Ensure beta estimates are from reasonable comparators – i.e., exclude U.S. utility beta estimates.[51]
2. If there is a desire or need for "mechanical approach" to adjusting current beta estimates, simply adjust them toward the long-term average of 0.35 rather than toward 1.0, as is done with published betas provided by services such as

[50] For example, Appendix B shows that Mr. Hevert's historical average Canadian beta estimates of 0.34 (monthly) and 0.38 (weekly) are just over half their U.S. counterpart estimates of 0.61 (monthly) and 0.72 (weekly), after accounting for leverage differences. The implied "unlevered" U.S. betas (0.234 monthly; 0.278 weekly) are almost double those for the Canadian utilities (0.131 monthly; 0.140 weekly). The utilities' experts' approach to estimating betas for Alberta utilities by using U.S. betas is centrally flawed, since they are too high to begin with, and hence not good comparables (i.e., as evidenced by their much high unlevered betas). They attempt to further compound this flawed approach by then determining unlevered betas for U.S. utilities using U.S. D/E ratios, which they then "relever" using higher Canadian D/E ratios. This approach ignores the fact that the unlevered betas are higher for U.S. utilities because they are not good comparators – because they have higher business risk.

[51] It is also obvious that Dr. Villadsen's U.S. pipeline company sample is clearly **not** a reasonable comparable group, with an average beta of 1.04, and with four of the six pipelines being rated BBB- and the other two being rated BBB+. This point was acknowledged by Mr. Coyne in response Coyne-UCA-2017NOV21-003a) when he stated: "Though electric and gas distributors are subject to some competitive risks, the severity of this risk is not comparable to the pipe-on-pipe competition and potential for stranded assets that occurs in the gas transportation pipeline sector."

Bloomberg and Value Line. I illustrate how to implement this approach in Appendix B.

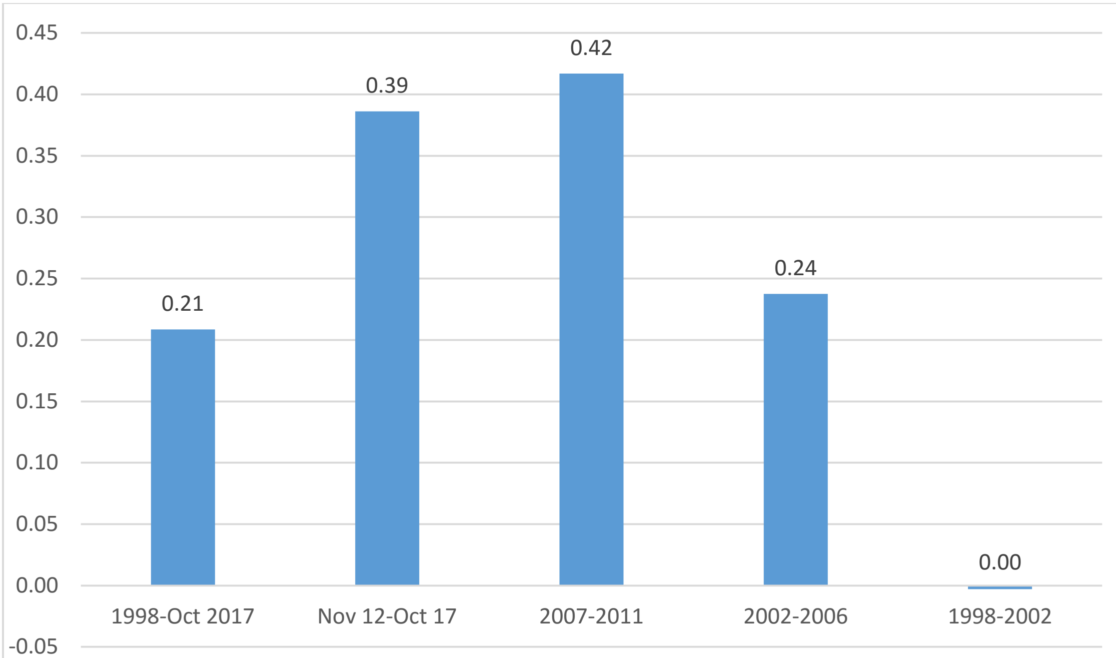
3. Based on historical evidence, establish a range of reasonable beta estimates with a lower bound of 0.30 and an upper bound of 0.60.
4. After collecting and considering as much evidence as possible, and given the constraints (i.e., permissible range) discussed in #3 above, make a simple judgment based on current beta estimates.

As noted above, a review of the utilities' experts' evidence shows that Canadian utility beta estimates over the last 22-25 years have averaged somewhere between 0.20 and 0.40 – with 0.35 representing the best estimate. Such evidence is consistent with my previous empirical estimates, but suggest that the 0.45 beta estimate I used in the 2013 and 2016 GCOC Proceeding is a little on the high side; however, it does represent the mid-point of the range of reasonable beta estimates that I have recommended to the Commission.

Figure 12 reports the average betas calculated using monthly total return data for the TSX Utilities Index over the 1998 to October 2017 period. The first reported beta estimate uses data for the entire 20-year period and is 0.21. The remaining beta estimates are for five-year periods, which is a commonly used time horizon for estimating betas with monthly data. The graph shows that the beta estimate for utilities was approximately 0 over the 1998 to 2002 period, which is one in which the betas for many industries, including utilities, were not meaningful due to the high technology boom and bust during that period. During 2002-06 the beta estimate was 0.24, then 0.42 during 2007-12, and finally is 0.39 for the most recent five-year period ending October 2017. This most recent five-year beta estimate of 0.39 is very much in line with the long-term average of 0.35 and the estimate of 0.45 that I used in the 2013 and 2016 GCOC Proceedings. The working papers for Figure 12 are appended as Exhibit I to my evidence.

FIGURE 12

BETA ESTIMATES FOR THE CANADIAN UTILITY INDEX (1998-Oct. 2017)



Data Source: CHASS database.

Table 8 provides beta estimates for several Canadian utilities as of November 2017, based on 60 months of returns. The average is 0.43, slightly above the 0.39 Utilities Index estimate over the November 2012-October 2017 period provided in Figure 12. The average increases slightly to 0.47 if we eliminate TransAlta and Northland, which are primarily non-regulated utilities. If we also exclude Canadian Utilities Ltd. and ATCO, which are holding companies that include interests in non-regulated assets, and we also exclude Algonquin, which also has a mix of regulated and non-regulated assets, then the average declines to 0.37.

TABLE 8

BETA ESTIMATES – NOVEMBER 2017

Firm	Beta
Fortis	0.41
Emera	0.20
TransAlta	NA
Northland Power	0.16
Algonquin Power	0.33
ATCO	0.99
Cdn Utilities Ltd.	0.48
Enbridge	0.59
TransCda	0.26
Average	0.43
Average excl. TransAlta and Northland	0.47
Average (Fortis, Emera, Enbridge, TransCda)	0.37

Source: Bloomberg, November 2017.

Based on the evidence in Figure 12 and Table 8, and combining it with long-term historical averages, a reasonable estimate of beta for a typical Alberta utility should lie within the 0.30 to 0.60 range. The current estimates I provide in Figure 12 and Table 8 average 0.40; however, in order to be consistent with my recommendations in the 2013 and 2016 GCOC Proceedings, I will use the mid-point figure of my recommended range (i.e., 0.30-0.60) of 0.45 as my best point estimate, which is slightly above the long-term average of around 0.35.

3.1.5. Final CAPM Estimates

Government bond yields remain low by historical standards, and A-rated Canadian utility bond yield spreads were sitting at 126 bp in November of 2017, much lower than the 200 bp observed in February of 2016, but still slightly above the long-term average spread of 100 bp. While this spread is quite small, I will adjust for it as I have in previous proceedings. Researchers at the Bank of Canada indicate that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian Utilities.[52] Consistent with this research, I will add half of the "above average" yield spread, or 0.13%, to my CAPM estimate to account for this time varying risk premium.

[52] Refer to: A. Garcia and J. Yang, "Understanding Corporate Bond Spreads Using Credit Default Swaps," Bank of Canada Review, Autumn 2009. This article is appended as Exhibit AR to this evidence.

Finally, I add 50 bp for financial flexibility (or flotation costs), consistent with previous Commission decisions, and is consistent with long-term estimates. Combining these items we get a range of CAPM estimates for the required equity return for the average regulated Alberta utility, which are reported in the table below. Based on these calculations my CAPM analysis suggests that 5.5% is a reasonable ROE (in the 4.05% to 6.93% range).

TABLE 9

CAPM ESTIMATES – 2018-2019

Estimate	RF (%)	MRP (%)	Beta	Spread Adjust. (%)	Financial Flex. (%)	Ke (%)
Max	3.0	5.5	0.60	0.13	0.50	6.93%
Min	2.2	4.5	0.30	0.00	0.50	4.05%
Best Estimate	2.6	5.0	0.45	0.13	0.50	**5.49%**

The CAPM parameters used (i.e., RF of 2.6%, MRP of 5% and the spread adjustment of 0.13%) imply a required return on the entire market of 7.73%, which is in line with, but at the high end of, the long-term market return expectations of finance professionals provided in Table 7, and is also in line with the long-term real returns on Canadian stocks. It is also very close to my best estimate of 7.5% for the long-term expected return on the market that I discussed previously. The **5.5%** estimate for the utilities is 50 bp below my CAPM estimate in the 2016 GCOC Proceeding despite the fact that I use the same beta estimate of 0.45, and that my RF estimate is actually 0.30% higher at 2.6% than it was in 2016. This is because the spread adjustment declined 0.37% (i.e., from 0.50% to 0.13%) which reflects lower yield spreads paid by Canadian utilities. Relatedly, the other contributing factor to my lower CAPM estimate is the use of an MRP of 5% to represent a normal risk market, versus the 6% MRP that I used in 2016 to reflect higher levels of risk aversion in the market as evidenced by elevated yield spreads and VIX levels. As discussed previously, all indications suggest risk aversion levels are now normal. Multiplying this 1% decrease in the MRP by the beta of 0.45 implies that this choice drove my CAPM estimate down by 0.45%.

3.1.6. Utilities' Experts' CAPM Estimates

Finally, it is instructive to compare my CAPM estimates with those that would have been provided by the utilities' experts if they used more reasonable assumptions for RF and MRP, and did not use adjusted betas or U.S. evidence. These estimates (for their Canadian utility samples) are provided in Table 10, with reference to the associated information response . They are based on an MRP of 4.25% (slightly below the 5% I used), and on the use of raw betas rather than adjusted betas. They range from 5.32% to 6.41%, with an average of 5.9%, which is reasonably close to my estimate of 5.5%, unlike the much higher CAPM estimates the utilities' experts obtain when they use inflated (i.e., adjusted) betas and MRP estimates.

TABLE 10

ADJUSTED CAPM ESTIMATES OF UTILITIES' EXPERTS

Expert	**Information Response**	**New Assumptions**	**CAPM Estimate**
Dr. Villadsen	Exhibit 22570-X0428, Villadsen-UCA-2017NOV21-015(b)	Use "raw" (unadjusted) betas / RF = 2.3% / MRP = 4.25% /	5.6% - adjust by 50 bp for financing charges to get 6.1%
Mr. Hevert	Exhibit 22570-X0496, Hevert-UCA-2017NOV21-033(b) Exhibit 22570-X0507, HEVERT-UCA-2017NOV21-033 Attachment	Use "raw" (unadjusted) betas / MRP = 4.25% /	4.82% (2017) to 5.52% (2018) - adjust by 50 bp for financing charges to get 5.32% (2017) and 6.02% (2018)
Mr. Coyne	Exhibit 22570-X0310, Coyne-UCA-2017NOV21-013 b) Exhibit 22570-X0325, Coyne-UCA-2017NOV21-013 b) Attachment 1	Use "raw" (unadjusted) betas / MRP = 4.25% /	6.41%
AVERAGE			**5.9%**

I have argued and provided supporting evidence in Section 3.1.4 and in Appendix B that it is inappropriate to use adjusted betas for regulated utilities with betas that do not approach, let alone average, 1 over the long term. Using the Empirical CAPM ("ECAPM") also implicitly adjusts the beta used in traditional CAPM estimates. Hence, the ECAPM should also not be used. Using both adjusted betas and the ECAPM together, as is done by Dr. Villadsen and Mr. Hevert, is clearly wrong and, in my view, should never be allowed.[53] The combination of the two approaches essentially adjusts raw betas up twice, and the impact of this is greater the

[53] I note that Dr. Villadsen and Mr. Hevert use different versions of the ECAPM, as illustrated in Table 11.

larger the MRP estimate that is used. I illustrate both of these facts in the top part of Table 11 using the estimates provided by Dr. Villadsen and Mr. Hevert that are reported in Table 10, and then in the bottom part of Table 11 using their individual MRP estimates of 8% and 13.1% respectively.

TABLE 11

ADJUSTED BETA AND ECAPM ESTIMATES

	Dr. Villadsen's ECAPM: **K = RF + Beta(MRP) + 1.5(1 – Beta)**			**Mr. Hevert's ECAPM:** **K = RF + 1/4×(MRP) + 3/4×Beta×(MRP)**		
Model	**RF = 2.3%; B (raw) = 0.77; MRP = 4.25%**			**RF = 2.3%; B (raw) = 0.77; MRP = 4.25%**		
	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM
CAPM with raw beta	5.573	---	0.77	4.81	---	0.575
CAPM with adj. beta	5.913	+0.340	0.85[54]	5.41	+0.60	0.716
ECAPM with raw beta	5.918	+0.345	**0.851**[55]	5.26	+0.45	**0.680**
ECAPM with adj. beta	6.138	+0.565	**0.903**	5.71	+0.90	**0.786**
	RF = 2.3%; B (raw) = 0.77; MRP = 8%			**RF = 2.3%; B (raw) = 0.77; MRP = 13.1%**		
	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM	K estimate (%)	Difference from Base case (%)	Implied Beta in Trad'l CAPM
CAPM with raw beta	8.460	---	0.77	9.90	---	0.575
CAPM with adj. beta	9.100	+0.64	0.85	11.75	+1.85	0.716
ECAPM with raw beta	8.805	+0.346	**0.814**	11.29	+1.39	**0.681**
ECAPM with adj. beta	9.325	+0.865	**0.878**	12.68	+2.78	**0.787**

Table 11 illustrates three important facts:

1. using either Dr. Villadsen's or Mr. Hevert's version of the ECAPM results in an implied higher beta if applied to the traditional CAPM (i.e., the one that is most widely used by analysts, CFOs, and investors – as discussed in Section 3.1.1);

[54] Calculated using the Adjusted Beta formula, so that Beta (adj) = 1/3 + 2/3(0.77) = 0.85.
[55] Calculated based on K = 5.918% in traditional CAPM, so Beta = (5.918 – 2.3)/(4.25) = 0.851.

2. using adjusted betas and the ECAPM accentuates the inappropriate upward adjustment of raw betas by doing it twice. This leads to large increases in cost of equity estimates versus those determined using the traditional CAPM; and,
3. the impact of these inappropriate upward beta adjustments is greater for larger MRP estimates, such as the inflated MRP estimates used by the utilities' experts.

These points confirm that the combination of using adjusted betas and ECAPM is not appropriate and should not be permitted, especially in combination with unrealistically high MRP estimates.

3.2. Discounted Cash Flow Estimates

3.2.1. DCF Model Overview

The Commission has appropriately taken DCF estimates into account in making previous decisions as to the appropriate ROE. I use two approaches and apply the DCF model as at the end of 2017 to:

1. find the implied rate of return for the overall market, which should be significantly higher than that for the average utility company which is much less risky than the "average" company in the market; and,
2. apply the models at the industry level using numbers that are representative of a typical publicly-traded utility company in Canada.

The model requires start of period market data and is based on estimating cash flows from now to infinity.

The DDM is a commonly used DCF model that assumes common shares can be valued according to the present value of their expected future cash flows, as represented by dividends. The constant-growth (or single-stage growth) version of the DDM is a simplification of the broader model that holds if we assume that the growth in dividends (and earnings) is expected to occur at the same annual rate indefinitely. The constant-growth model can be represented as:

$$\text{Price} = D_0(1 + g) / (Ke – g) = D_1/(Ke – g)$$

Where,

Price is the firm's most recent common share market price

D_0 represents the dividends paid over the most recent 12-month period

g represents the expected long-term average growth rate in dividends and earnings

Ke represents the required returns by a firm's common shareholders.

The single-stage DDM is convenient in the sense that it can be easily arranged to solve for the implied rate of return on common shares, as follows if we know their current price and dividends, and can estimate a long-term consistent growth rate:

$$Ke = (D_0/\text{Price})\times(1 + g) + g$$

3.2.2. Market DCF Estimates

Table 1 showed that real GDP growth averaged 3.2% over the 1962 to 2016 period. This provides one potential estimate of long-term growth that could be used in the single-stage model, since we would expect long-term growth for the overall market to gravitate towards this figure. This assumption is commonly made by financial analysts. Table 1 also showed that average real GDP growth has been lower at 2.5% since 1992, and we could also use this as a long-term growth estimate. Finally, the October 2017 Consensus forecasts suggested real GDP growth for Canada of 1.8% over the 2023-2027 period, with similar growth rates during 2018-2020, so this provides another reasonable estimate of future Canadian economic growth. Of course, we are trying to estimate a "nominal" required rate of returns, so we should use nominal GDP growth as "g." We can estimate nominal growth rates by applying the 2% Bank of Canada inflation target, which is also the average expected inflation rate over the 2023-2027 period according to the October 2017 Consensus forecasts. Doing so, we get the following long-term nominal Canadian GDP growth rate estimates that correspond to the three real growth rates noted above: 5.26%; 4.55%; and, 3.84% - where 4.55% represents the average and mid-point of these three figures. These growth rates are in line with those used by security analysts when they use single-stage growth models to value securities (i.e., they usually use numbers in the 3-5% range *when* they use single period models).

The dividend yield for the S&P/TSX Composite Index as of November 24, 2017 was 2.7%. This is the "lagged" dividend yield (i.e., D0/Price) since it is estimated using dividends over the most recent 12-month period. Substituting the maximum, minimum and average nominal GDP growth estimates noted above into the single-stage DDM equation provided above, we get the following estimates for the implied equity return for the market as a whole for 2018:

Max: $Ke = (D0/Price)\times(1 + g) + g = (0.027)\times(1.0526) + .0526 = 0.0810$ or 8.10%

Average: $Ke = (0.027)\times(1.0455) + .0455 = 0.0737$ or **7.37%**

Min: $Ke = (0.027)\times(1.0384) + .0384 = 0.0664$ or 6.64%

Despite the limitations of the model, and with the simplifying assumption of constant growth indefinitely, these seem to be reasonable estimates. The average of 7.37% is consistent with my long-term forecast for expected market returns of 7.5%, and all three estimates are in line with market forecasts of expected future returns that were provided in Table 7 and that were discussed earlier. The average estimate of 7.37% is also very close to my CAPM market estimate of 7.7% (discussed in Section 3.1.5).

We can overcome one limitation of the single-stage growth model by using a variation of the DDM, called the H-Model. The H-Model is a multi-stage growth version of the DDM. It assumes that growth in dividends moves in linear fashion from some current short-term growth rate (defined as g_S) toward some long-term growth rate (defined as g_L) over a specified period of time, defined as 2H, where H is hence defined as the "half-life." It also offers the advantage that, similar to the single-stage DDM, it can be rearranged to determine a finite solution for Ke, which is shown below:

$$Ke = (D_0/Price)\times[(1 + g_L) + H(g_S - g_L)] + g_L$$

I consider the Consensus GDP Growth forecasts that translated into a 3.84% nominal GDP growth rate as my short-term growth rate (g_S), and use the long-term GDP nominal growth rate estimate of 5.26% as the long-term growth rate (g_L). Assuming it takes four years to get back to this long-term expected growth rate, then we would use H = 2, which provides an estimate for Ke of 8.03%. If we assume that this return to long-term growth takes longer (say

8 years), then H = 4, and we get an estimate for Ke of 7.95%. The mid-point of these two estimates is 7.99%, which I round up to 8% for simplicity.

Combining the results from the two DDM models, we get estimates for Ke for the market in the 6.6-8.1% range. I will use the average estimate of 7.4% from the single-stage DDM and 8.0% using the H-model to arrive at 7.7% as my best estimate of the implied return on the market using DCF models. This number is reasonable, very close to my estimate for future market returns of 7.5% discussed in Section 3.1.3, and in line with the expectations of finance professionals and with historical real stock returns. It is also exactly the same as my CAPM estimate for the entire market that was provided earlier. DCF models will work better in aggregate than for Canadian utilities, which leaves us with the issue of how to adjust these figures into a reasonable implied return for utilities that possess considerably less risk than the average company in the market. At minimum, we could say that the market DCF estimates (similar to my CAPM market estimate) suggest that utility returns should be lower than 7.7%.

3.2.3. Alberta Utility DCF Estimates

I will now apply both of the DCF models discussed above to Canadian utilities. Of course, determining the inputs here is somewhat trickier than for the broad market. A common way of estimating the growth rate for companies is to determine the company's **sustainable growth rate,** which can be estimated by multiplying the earnings retention ratio (which equals "1 – dividend payout ratio") by the ROE, as shown below:

$$g = (1 - \text{payout ratio}) \times \text{ROE}.$$

The intuition behind the use of this formula is that growth in earnings (and dividends) will be positively related to the proportion of each dollar of earnings reinvested in the company multiplied by the return earned on those reinvested funds, which can be measured using ROE. For example, a firm that retains all its earnings and earns 8% on its equity would see its equity base grow by 8 percent per year. If the same firm paid out all of its earnings, it would not grow. It should work quite well for utility firms that pay a significant proportion of their earnings out as dividends, and that possess relatively stable ROE figures that are generally close to allowed ROEs, which do not usually fluctuate by large amounts.

Table 12 below includes summary statistics on dividend yield, payout ratios and ROE for the 9 Canadian utility firms included in Table 8. This data can then be used to estimate sustainable growth rates for the utilities, and ultimately the implied required rate of return using our two DCF models. Panel A reports the average, median, maximum and minimum figures for all 9 utilities for the November 2017 dividend yield ("**DY**"), the average 5-year DY, the 2016 payout ratios and ROEs, and the 2007-16 averages for payout and ROE.[56] Panel B reports the same statistics after eliminating TransAlta and Northland, and Panel C after also eliminating ATCO, Canadian Utilities, and Algonquin. The working papers for Table 12 are appended to my evidence as Exhibit J.

[56] Payout ratios were "capped" at 100% to control the influence of extreme payouts on "averages" - this process obviously had no effect on the reported medians.

TABLE 12

DCF INPUT ESTIMATES – 2007-2016 FIGURES

	DY (Nov 17)	5-year Avg DY	2016 Payout	Avg Payout (07-16)	2016 ROE	Avg ROE (07-16)
Panel A						
Average	3.89	4.26	86.26	72.40	8.16	8.77
Median	4.00	3.80	85.40	72.45	7.03	9.16
Max	4.90	8.00	100.00	100.00	15.69	12.58
Min	2.20	2.10	53.00	59.14	0.72	3.29
Panel B						
Average (excl TransAlta and Northland)	4.03	3.46	83.97	66.00	7.58	10.50
Median	4.00	3.70	85.30	69.28	7.03	11.10
Max	4.90	4.40	100.00	83.97	13.40	14.33
Min	2.90	2.10	53.00	47.47	0.72	4.63
Panel C						
Average (Fortis, Emera, Enbridge, TransCda)	4.28	3.68	88.53	75.17	6.12	10.10
Median	4.30	3.75	85.40	77.69	5.18	10.93
Max	4.90	4.10	100.00	88.53	13.40	13.50
Min	3.60	3.10	80.20	58.93	0.72	3.55

Data Source: Morningstar at www.morningstar.ca.

The summary statistics included above appear reasonable for a typical regulated and publicly-traded Canadian utility in several regards. Payout ratios between 66% and 88%, and gravitating toward an average of 66-75%, are in line with historical figures and also with the high dividend paying nature of such profitable, slow growing firms. Similarly, dividend yields in the 3.5-4.5% range are in line with that of the S&P/TSX Utilities Index. The ROE numbers in the 6-10.5% range are also reasonable.

It is difficult to find “typical” or representative Canadian regulated publicly-traded utilities. However, using averages and medians (which offset to some extent the influence of extreme observations) provides a useful starting point. Columns 2 and 3 of Table 13 provides estimates of sustainable growth rates (g) using the ROE and payout averages and medians reported in Table 12. These are calculated using the formula above (i.e., g = (1 – payout) × ROE). Column 2 uses the average and median ROE and payout figures for 2016, while column 3 uses the averages over the 2007 to 2016 period. The median and average growth rates range from 0.70% to 3.57%, with an average (and median) of 1.9%. This seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth in the 3.8-5.3% range.

TABLE 13

DCF GROWTH AND SINGLE STAGE DDM ESTIMATES

	Implied g (2016)	**Implied g (07-16)**	**Implied Ke (2016 g and Nov 2017 DY)**	**Implied Ke (07-16 g and 5-year DY)**
Average	1.12	2.42	5.05	6.78
Median	1.03	2.52	5.07	6.42
Average (excl TransAlta and Northland)	1.21	3.57	5.29	7.15
Median	1.03	3.41	5.07	7.24
Average (Fortis, Emera, Enbridge, TransCda)	0.70	2.51	5.01	6.27
Median	0.76	2.44	5.09	6.28
Average of 6 averages g = 1.92%				**Average of 6 averages Ke = 5.93%**
Average of 6 medians g = 1.86%				**Average of 6 medians Ke = 5.86%**

The final two columns in Table 13 report the Ke estimates that are derived using the single-stage DDM and inputting the appropriate growth estimates from column 2 or 3 along with the corresponding dividend yield (reported in Table 12). Recall this formula can be represented as follows when we begin with the dividend yield based on dividends over the previous 12 months: $Ke = (D_0/Price) \times (1 + g) + g$. The working papers for Table 13 have been appended to my evidence as Exhibit J.

These estimates range from a low of 5.01% using 2016 implied growth and November 2017 DY average numbers and considering only Fortis, Emera, Enbridge and Trans Canada, to a high of 7.24% using 2007-16 median values after excluding Transalta and Northland. As mentioned, it is difficult to determine which group provides the most representative statistics, so it is useful to determine the average of all these estimates. The average of all 6 Ke estimates determined using averages is 5.93%, while the average of the 6 numbers calculated using the medians is 5.86%. I will assign a best estimate single-stage DDM estimate at the mid-point of 5.9%. This estimate is below the 7.7% DDM estimate for the market, which is reasonable since regulated utilities are considerably less risky than the average company. If we add 50 basis points for flotation costs, we end up with a range of 5.5%-7.7%, with a best estimate of 6.4%.

Similar to the approach used above to estimate Ke for the market, I will now apply the H-Model to estimate the implied rate of return for a typical Canadian utility. This model requires two growth estimates – the short-term rate (g_S), and the long-term rate (g_L). I will denote g_S as the implied growth rates determined using 2016 payout ratios and ROEs, which are reported in column 2 of Table 13. I then denote as g_L the implied growth rates using long-term averages for payout and ROE, which are reported in column 3 of Table 13. The underlying rationale is that growth rates estimated over a longer period of time are more representative of those that can be expected in the long run. The results of this analysis are reported in Table 14 below. The working papers for Table 14 are appended to my evidence as Exhibit K.

1 **TABLE 14**

2 **H-MODEL ESTIMATES**

Using all 9 Utilities		
	H=2	**H=1**
Current D0/P0	0.0389	0.0389
gs (current sustainable g)	0.0112	0.0112
gL (long-term sustainable g)	0.0242	0.0242
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0112	0.0112
g1	0.0145	0.0177
g2	0.0177	0.0242
g3	0.0210	0.0242
g4	0.0242	0.0242
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0630**	**0.0635**
Excl TransAlta and Northland		
Current D0/P0	0.0403	0.0403
gs (current sustainable g)	0.0121	0.0121
gL (long-term sustainable g)	0.0357	0.0357
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0121	0.0121
g1	0.0180	0.0239
g2	0.0239	0.0357
g3	0.0298	0.0357
g4	0.0357	0.0357
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0755**	**0.0765**
Fortis, Emera, Enbridge, TransCda		
Current D0/P0	0.0428	0.0428
gs (current sustainable g)	0.0070	0.0070
gL (long-term sustainable g)	0.0251	0.0251
H = 2 (i.e., 4-year transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0070	0.0070
g1	0.0115	0.0160
g2	0.0160	0.0251
g3	0.0206	0.0251

g4	0.0251	0.0251
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0674**	**0.0681**
AVERAGE	**0.0686**	**0.0694**

The Ke estimates lie within the range of 6.3% to 7.7%. The average estimate is 6.86% if we assume a 4-year transition in growth rates (i.e., H =2), and is slightly higher at 6.94% if we assume a 2-year transition. Combining these results with a 0.50% allowance for flotation costs, we get the following ranges and point estimates: 6.8-8.2% with a best estimate of 7.4%. The Ke estimates from the H-Model are higher than the averages derived using the single-stage model. This is because the model implicitly assumes that growth rates will gravitate to longer term average rates, which were higher than the implied rates using 2016 data only. I weight the estimates from the constant-growth model and the H-Model equally in arriving at my final DCF estimates.

A summary of the DCF estimates determined above is provided in Table 15 for the market and for Alberta utilities. The DCF analysis suggests a 7.7% required return on the market with a range of 6.6-8.1%. As discussed previously, this estimate equals exactly my CAPM estimate of 7.7% and is consistent with current estimates of finance experts and historical long-term real stock returns. For utilities, after including a 50 basis point flotation cost allowance, the results suggest a required return with a range of 5.5-8.2% and a best estimate of 6.9%. This estimate is 1.3% below my DCF estimate for the market (if we also adjusted the market estimates 50bps for flotation costs), which is consistent with the below-average risk of utilities.

TABLE 15

DCF ESTIMATE SUMMARY

Year	Model	Minimum	Maximum	Best Estimate	Flotation Costs Adj.	Range	Final Estimate
Panel A: Market Estimates							
Single-Stage		6.6	8.1	7.4	0.50	7.1-8.6	7.9
H-Model		7.95	8.03	8.0	0.50	8.45-8.53	8.5
Combined		6.6	8.1	7.7	0.50	7.1-8.6	**8.2**
Panel B: Utility Estimates							
Single-Stage		5.0	7.2	5.9	0.50	5.5-7.7	6.4
H-Model		6.3	7.7	6.9	0.50	6.8-8.2	7.4
Combined		5.0	7.7	6.4	0.50	5.5-8.2	**6.9**

3.2.4. Utilities' Experts' DCF Estimates

I disagree with the utilities' experts' use of analyst earnings growth estimates because they are simply too high. This stance is consistent with the following statement of the Commission in the 2013 GCOC Decision:

> For example, analysts' forecasts of growth rates are forward-looking and aim to expressly account for events expected in the future. However, these same forecasts tend to incorporate a **high degree of subjectivity** and may be **overly optimistic**.[57]

Consistent with its concerns regarding the use of overly optimistic and subjective forecasts that are assumed in perpetuity, in the 2016 GCOC Decision, the Commission confirmed its policy of **not** accepting growth estimates that exceed those of expected nominal GDP growth noting:

> Consistent with its determinations in prior GCOC decisions, the Commission **will not accept**, in a single-stage DCF model, the use of long-term or terminal growth rates that exceed estimates of the nominal long-term GDP growth rate for the economy.[58]

As a result, the Commission did **not** consider the single-stage DCF estimates of Mr. Hevert or Dr. Villadsen in 2016, since the single-stage growth estimates used by both experts violated the condition noted above. Nonetheless, Table 16 below shows clearly that the single-stage DCF Canadian sample estimates of all three utilities' experts should be rejected in these proceedings for exactly the same reason. In other words, they all use growth rates in

[57] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 180 [emphasis added].
[58] Decision 20622-D01-2016, 2016 Generic Cost of Capital, para. 287 [emphasis added].

perpetuity that exceed (by a wide margin) their own estimates for nominal GDP growth in Canada, with the average growth rate used (i.e., 7.25%) being a full 3.01% above the average GDP growth rate estimate of 4.24% - or 71% higher.

TABLE 16

CANADIAN SINGLE STAGE DCF ESTIMATES OF UTILITIES' EXPERTS

Expert	Growth Rate used in DCF	Nominal GDP Growth Rate Estimate	Initial Estimate of Cost of Equity (Ke)	Ke Estimate using GDP Growth Rate
Dr. Villadsen	8.3%	3.85%	13.1%	8.5%[59]
Mr. Hevert	7.5%	5.02%	11.35%	8.8%[60]
Mr. Coyne	5.96%	3.85%	10.85%	8.6%[61]
AVERAGE	**7.25%**	**4.24%**	**11.77%**	**8.63%**

Table 16 also provides the single-stage DCF estimates that would have resulted if the utilities' experts had used their own nominal GDP estimates, and hence not violated this condition. The resulting equity cost estimates decline substantially (by an average of 3.14%), as one would expect. They remain elevated (i.e., averaging 8.6%) because even the assumption of nominal GDP growth (i.e., average growth) is an ambitious target for regulated utilities that operate virtual monopolies in mature markets, with little opportunity for dramatic growth.[62] This point was also acknowledged previously by the Commission, at in the 2013 GCOC Decision:

> However, the Commission is also mindful that, as both experts acknowledged, **the GDP growth rate may be an ambitious target** for long-run earnings growth in respect of low-risk, mature, utilities.[63]

So, in summary, all of the single-stage Canadian DCF estimates provided by the utilities' experts should be rejected since they use growth rates that exceed nominal GDP growth rates. Even if we adjusted their single-stage DCF estimates downward by using GDP growth,

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[59] Exhibit 22570-X0428, Information Response to Villadsen-UCA-2017NOV21-016(e).
[60] Exhibit 22570-X0496, Information Response to Hevert-UCA-2017NOV21-020(b.
[61] Exhibit 22570-X0310, Information Response to Coyne-UCA-2017NOV21-017. See also Exhibit 22570-X0328, Coyne-UCA-2017NOV21-017 a) Attachment.
[62] Hence the fact that the average growth estimates obtained using analyst estimates are much higher than expected GDP growth rates indicates that concerns regarding overly optimistic analyst estimates are valid.
[63] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 190 [emphasis added] [footnote omitted].

these estimates would still be too high, since this represents an ambitious growth target for regulated Alberta utilities.

I now turn my attention to the utilities' experts' multi-stage DCF estimates. In the 2016 GCOC Decision, the Commission noted:

> Dr. Cleary further noted that Dr. Villadsen's growth estimates are above the long-term nominal growth rate for 10 years and, therefore, violate the upper limit on growth in the DCF model from the 2013 GCOC decision.[64]

This statement is referring to Dr. Villadsen's multi-stage DCF estimates. The rationale for this statement is as follows. First, let's denote g_{GDP} as the expected growth rate of nominal GDP. Since the growth rates used by the utilities' experts exceed g_{GDP} during years 1-10, and they then use g_{GDP} for years 11 to infinity, then this is equivalent to using one constant growth rate from now to infinity that is greater than g_{GDP}. This is simply a mathematical fact, which I illustrate below (using a time horizon of 100 years for simplicity purposes):

> Suppose: g(years 1-5) = 7%; g(years 6-10) = 5%; and, g(years 11-100) = 4% (which we will assume equals g_{GDP}).
>
> We can solve the equation below for "g_{LT}" to find the one constant perpetual growth rate that would result in $1 growing to the same amount after 100 years, as it would have if it grew by 7% for the next five years, then 5% for the next five years, then grew by 4% from years 11 to infinity:
>
> $$(1.07)^5 \times (1.05)^5 \times (1.04)^{90} = (1 + g_{LT})^{100}$$
>
> $$(61.0753)^{1/100} - 1 = g_{LT}$$
>
> So, **g_{LT} = 4.20% which is > 4% (i.e., g_{GDP})**
>
> This is the implied constant perpetual growth rate from time 0 to infinity that is equivalent to 7% growth for the next five years, 5% for the following five years, then 4% to infinity.

---

[64] Decision 20622-D01-2016, 2016 GCOC Decision, para. 264.

All three utilities' experts' multi-stage DCF estimates begin with very high growth rates in year 1 (i.e., Villadsen – 8.3%; Hevert – 7.5%; and, Coyne – 5.96%). Their models work such that these high growth rates decline eventually (i.e., after 10 *long* years) to a somewhat ambitious long-term terminal growth rate (i.e., estimated nominal GDP growth). Hence, all of their multi-stage DCF estimates clearly violate the condition that the Commission has expressed with regards to using growth rates in a single-stage DCF model that exceed expected nominal GDP growth. In other words, the implied constant perpetual growth rate (i.e., g_{LT}) from the growth rates used in Dr. Villadsen's multi-stage DCF estimates would exceed her estimate of 3.85% for Canadian nominal GDP growth. Similarly, the implied perpetual growth rates for Mr. Hevert and Mr. Coyne would exceed their estimates of Canadian nominal GDP growth of 5.02% and 3.85% respectively. Since all of their estimates clearly violate this condition, they should all be rejected. This explains why they all obtain such high cost of equity estimates using their multi-stage DCF models.

3.3. Bond Yield Plus Risk Premium Estimates

The BYPRP approach adds a risk premium (generally in the 2-5% range) to the yield on a firm's outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium used in CAPM, which represents the premium above government risk-free yields and expected market stock returns. The BYPRP approach is depicted below:

Ke = Company's Bond Yield + Company Risk Premium

It is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts[65] and by over 50 percent of Canadian CFOs.[66]

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable

[65] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. This presentation is appended to this evidence as Exhibit AC.
[66] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" Multinational Finance Journal 15-3, 2011. This article is appended to this evidence as Exhibit AE.

market-determined bond yields, to estimate a required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these required returns (i.e., the greater the risk premium).

This approach provides useful reasonableness checks on CAPM and other estimates, and employs solid intuition. For one thing, it overcomes technical issues that arise when beta estimates are suspect due to extreme market movements, such as those observed during the early 2000s. In fact, there is a relationship with the CAPM in several ways. For example, the firm's yield on outstanding debt will be related to RF, as well as to yield spreads which will vary with market conditions, just as the MRP does in the CAPM. Also, we can "adjust" the risk premium applied to a particular firm according to its riskiness - one measure of which might be by making reference to its typical beta.

The first step is to obtain an estimate of the cost of long-term yields on a typical utility. As of November 15, 2017 the yield on long-term A-rated Canadian utility bonds was 3.51% according to the Bloomberg data used to construct Figure 3. This number is close to the yields on outstanding Canadian utility bonds around the same time. For example the following yields were observed as of December 28, 2017:[67]

- CU Inc. bonds maturing November 19, 2046 – yield was 3.43%
- FortisAB Inc. bonds maturing September 21, 2046 – yield was 3.42%
- Hydro One bonds maturing October 19, 2046 – yield was 3.48%

This evidence implies that 3.5% is a reasonable starting point for my BYPRP estimate.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of

[67] http://www.pfin.ca/canadianfixedincome/Default.aspx, December 28, 2017.

2.5%. Combining this information, I obtain the following 2018-2019 estimates for Ke according to this approach:

Minimum: Ke = 3.5 + 2 = 5.5%

Maximum: Ke = 3.5 + 3 = 6.5%

Best Estimate: Ke = 3.5 + 2.5 = 6.0%

If we add 50 bp for flotation costs, we end up with Ke estimates in the 6-7% range, with a **best estimate of 6.5%**. This is 50 bp lower than my estimate in the 2016 GCOC Proceeding, which reflects the fact that A-rated bond yields have declined to 3.5% from about 4% at the start of 2016 when I prepared my evidence in that proceeding. This 6.5% estimate is 1% above my CAPM estimate of 5.5% and 0.40% below my DCF estimate of 6.9%.

Mr. Hevert calculates ROE estimates using what he claims is the BYPRP approach. However, he implements his BYPRP model by finding the difference between allowed ROEs in the U.S. and then comparing these allowed ROEs to Government of Canada bond yields to determine the Canadian figures, and by comparing the allowed ROEs to U.S. government bond yields to determine the U.S. figures. This is incorrect, since the BYPRP model, according to the CFA literature (and numerous other textbooks), and which is commonly used in analyst reports, adds a risk premium to the present yield on a firm's outstanding publicly-traded long-term bonds.[68] It therefore estimates a market-based return based on the yield on a company's outstanding bonds, which is reflective of market yield spreads. It does not use government yields, nor does it use ROEs and it certainly does not use allowed ROEs. Furthermore, the Commission has not applied allowed ROEs in other jurisdictions in previous decisions, including the 2013 GCOC Decision and the 2016 GCOC Decision.

As a result, in the 2016 GCOC Decision, the Commission did not place any weight on the results of Mr. Hevert's BYPRP model:

[68] For example, refer to page 77, Equity Asset Valuation, 3rd Edition, Pinto, Henry, Robinson and Stowe, 2015, John Wiley & Sons Inc., New Jersey. An excerpt is appended to this evidence as Exhibit BA.

> Consistent with its determinations in the 2009 GCOC decision, the Commission did not place any weight on the results of Mr. Hevert's and Dr. Villadsen's risk premium models that use the authorized ROEs granted by the U.S. regulators.[69]

Given that nothing has changed with respect to his BYPRP model or his implementation of it, his estimates should also be rejected in the current proceeding. His model uses U.S. allowed ROEs (which the Commission does not accept), it has no theoretical support, and there is no rationale supporting the relevance of a comparison of Government of Canada bond yields to allowed ROEs for regulated utilities in the U.S. (which may or may not have anything to do with existing market conditions).

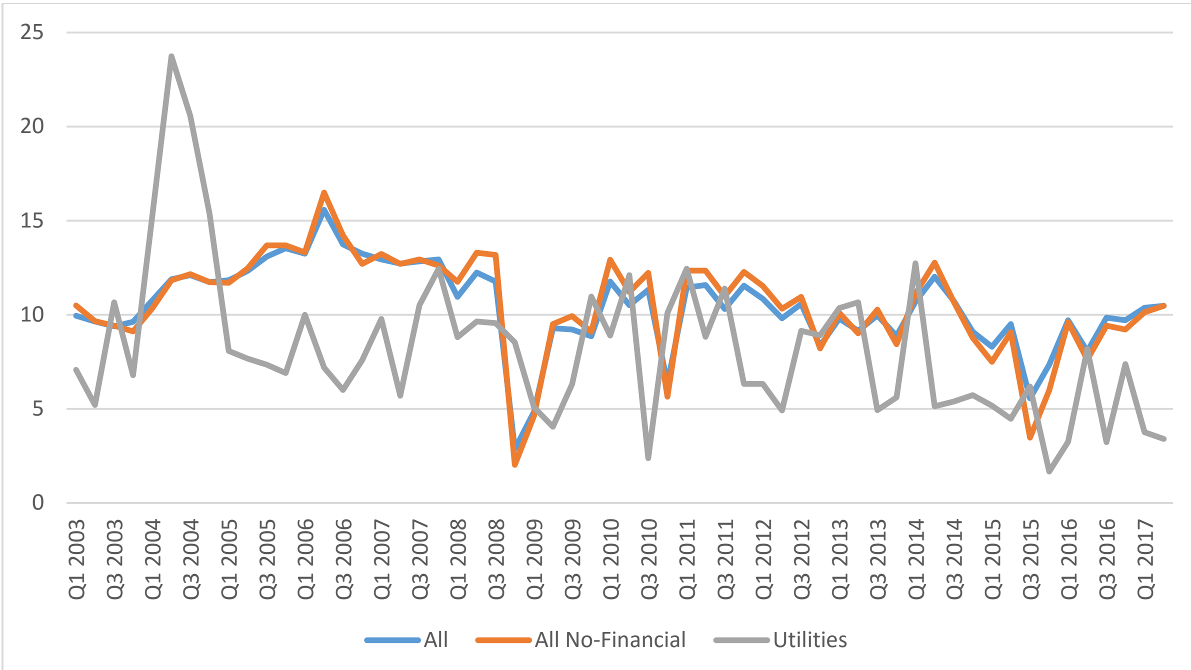
3.4. ROEs and Price-to-Book Ratios

Figure 13 depicts annualized quarterly ROE data for Canadian firms and Canadian utilities from Q1-2003 to Q2-2017. Over this period, the average ROE for all companies was 10.5%, 10.6% for all non-financial companies, and 8.2% for utilities. We can see that it was generally a good period for all types of companies in terms of ROEs, which fell between 2.9 and 15.6% for all companies, 2.0 and 16.5% for all non-financials, and 1.7 and 23.7% for utilities. The working papers for Figure 13 are appended to my evidence as Exhibit L.

[69] Decision 20622-D01-2016, 2016 GCOC Decision, para. 255

FIGURE 13

CANADIAN ROEs– Q1-2003 to Q2-2017



Data Source: CANSIM.

Table 17 provides similar positive results for Alberta utilities over the 2011 to 2016 period according to their Rule 005 reports with annual averages ranging from 8.8% to 9.7%, and always above the allowed ROE. The six-year overall average was 9.38%, which is 0.93% above the average allowed ROE over the period of 8.45%. So overall, we can say that these utilities have generated ROEs that were generally above the allowed rates of 8.75% (2011-12) and 8.3% (2013-16), with Alberta ROEs averaging 9.52% since 2013, or 1.22% above the allowed ROE of 8.3%. The average ROE of 9.4% is higher than the 2007-Q2/2017 average of 8.2% provided in Figure 16, below, for Canadian utilities, and the 2007-2016 average of 8.77% provided earlier in Table 12 for the Canadian utilities used in the DCF analysis.

TABLE 17

REPORTED ROEs – ALBERTA UTILITIES 2011-2016

Reported ROEs	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**Average**	**Median**
Fortis Alberta	9.70%	11.12%	9.77%	9.49%	9.99%	9.73%	9.97%	9.75%
ATCO Elec Dist	13.03%	9.90%	9.74%	10.99%	12.14%	11.50%	11.22%	11.25%
ATCO Gas	12.93%	11.10%	10.95%	11.86%	11.01%	10.98%	11.47%	11.06%
AltaLink	8.21%	8.44%	8.44%	8.77%	9.28%	9.48%	8.77%	8.61%
ATCO Pipelines	11.39%	9.80%	10.31%	10.16%	11.16%	11.53%	10.73%	10.74%
ATCO Elec Trans	9.14%	8.23%	8.91%	9.84%	10.66%	9.87%	9.44%	9.49%
AltaGas	5.83%	6.16%	11.27%	12.50%	10.17%	6.19%	8.69%	8.18%
ENMAX Dist	9.93%	6.15%	7.82%	8.05%	10.22%	6.71%	8.15%	7.94%
ENMAX Trans	10.33%	11.48%	7.09%	5.90%	0.49%	4.08%	6.56%	6.50%
EPCOR Dist	8.98%	10.37%	10.31%	9.74%	8.10%	8.03%	9.26%	9.36%
EPCOR Trans	6.94%	8.90%	11.59%	7.17%	10.82%	8.36%	8.96%	8.63%
Average	9.67%	9.24%	9.65%	9.50%	9.46%	8.77%	9.38%	9.48%
Median	9.70%	9.80%	9.77%	9.74%	10.22%	9.48%	9.79%	9.76%
Allowed ROEs	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	8.45%	8.30%

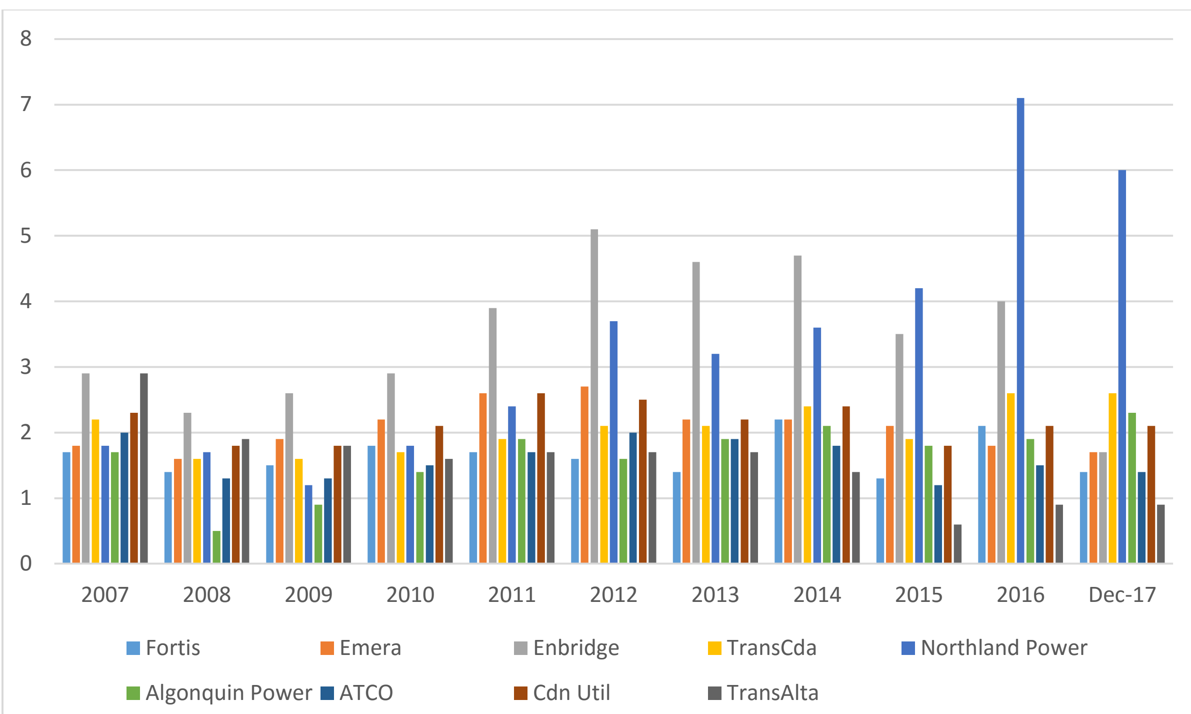
Data Source: Rule 005 reports.

ROE data suggest that Alberta utilities have earned an ROE that is almost as much as the average Canadian company, yet we know that they are less risky than average. In fact, the reported ROE numbers are above the required return estimates determined using the CAPM, DCF and BYPRP approaches, with best estimates of 5.5%, 6.9% and 6.5% and which ranged from 4.1% to 8.7%. All of this suggests that Alberta utilities would make attractive investments. Certainly, from an investor's point of view, low-risk utilities that have regulated returns that exceed *required* rates of return based on their risk level are attractive. For example, assume an investor used CAPM to determine his required rate of return for an average regulated utility and arrived at the 5.5% figure that was determined above. If the utility earned the currently allowed ROE of 8.5%, then that investor would surely be pleased. Of course, this does not mean that the actual return on the stock was 8.5%; however there is an obvious relationship between the two. I will examine this relationship by reference to P/B ratios and stock returns.

I begin by considering the P/B ratios for the utilities discussed previously in the DCF analysis. The individual P/B ratios for the firms are presented in Figure 14. It is obvious that almost all of the ratios are above 1 throughout the entire period, with the exception of the P/B ratios for Transalta since 2015, and for Algonquin in 2008 and 2009. The summary statistics provided in Table 18 show that the average P/B ratio has generally exceeded 2 since 2011, and is presently in the 1.85 to 2.23 range, depending on which sub-set of firms is considered. The working papers for Figure 14 and Table 18 have been appended to my evidence as Exhibit M.

FIGURE 14

UTILITY P/B RATIOS – 2007-Dec 2017



Data Source: Morningstar at www.morningstar.ca.

TABLE 18

P/B RATIO SUMMARY STATISTICS (2006-Dec 2017)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Dec-17
Average	2.14	1.57	1.62	1.89	2.27	2.56	2.36	2.53	2.04	2.67	2.23
Median	2.00	1.60	1.60	1.80	1.90	2.10	2.10	2.20	1.80	2.10	1.70
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	4.20	7.10	6.00
Min	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.40	0.60	0.90	0.90
Average excl TransAlta and Northland	2.09	1.50	1.66	1.94	2.33	2.51	2.33	2.54	1.94	2.29	1.89
Median	2.00	1.60	1.60	1.80	1.90	2.10	2.10	2.20	1.80	2.10	1.70
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	4.00	2.60
Min	1.70	0.50	0.90	1.40	1.70	1.60	1.40	1.80	1.20	1.50	1.40
Average (Fortis, Emera, Enbridge, TransCda)	2.15	1.73	1.90	2.15	2.53	2.88	2.58	2.88	2.20	2.63	1.85
Median	2.00	1.60	1.75	2.00	2.25	2.40	2.15	2.30	2.00	2.35	1.70
Max	2.90	2.30	2.60	2.90	3.90	5.10	4.60	4.70	3.50	4.00	2.60
Min	1.70	1.40	1.50	1.70	1.70	1.60	1.40	2.20	1.30	1.80	1.40

Data Source: Morningstar at www.morningstar.ca.

Generally speaking, higher P/B ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning rates of return that are at least "fair," if not above fair. This is consistent with the Commission's statement in the 2011 GCOC Decision. The Commission confirmed the usefulness of P/B ratios in the 2013 GCOC Decision, noting:

> Overall, the Commission confirms its findings in Decision 2011-474 that an examination of a given company's P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility's awarded ROE to ensure that it is sufficiently able to

attract investment in the capital markets at reasonable rates and maintain its financial integrity.[70]

The constant-growth DDM can actually be rearranged to show that the appropriate P/B ratio can be expressed as:[71] P/B = (ROE – g) / (Ke – g)

This expression implies that P/B ratios will be greater than one if actual ROE > Ke, will equal one if Ke = ROE, and will be less than one when ROE < Ke. This is consistent with the discussion above. If we "plugged" the average 2003-Q2/2017 utility index ROE of 8.2% into the equation, as well as current average P/B ratios of 2.23, 1.89, and 1.85, and then used a 3% long-term growth rate, we would get implied Ke figures of 5.33%, 5.75% and 5.81% respectively. These estimates are 33-81 basis points above my CAPM estimate of 5% provided above if we subtract the 0.50% that was added for financial flexibility, and are in line with, but slightly below, my single-stage DCF estimate of 5.9% (before the 0.5% adjustment). While I will not assign any weight to this estimate for purposes of determining Ke, the bottom line of this discussion is that the P/B ratios for utilities reported above indicate that Canadian utilities appear to be earning a satisfactory (or more than satisfactory) ROE, and have done so for quite some time.

3.5. Summary of ROE Calculations

I have weighted all three estimates equally, as I did in my 2013 and 2016 evidence, because all three methods are used in practice. CAPM is more heavily relied upon in practice due to its conceptual advantages. For example, returning to the previous studies that were cited with respect to DCF approaches, they were used by:[72]

- only 15% of U.S. CFOs - versus over 70% for CAPM;[73]
- about 12% of Canadian CFOs - versus close to 40% for CAPM;[74]

[70] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 221.
[71] This is true if we use the following sustainable growth rate for "g" in the DDM: g = (1 – payout) × ROE.
[72] DCF estimates of Ke were not used by any of the analysts in the Robinson (2007) survey, in which 68% used CAPM. This is because the focus was on which discount rate would be used "in" DCF models, so the use of a discount rate determined by such models would be inappropriate, since it lead to a "circular argument."
[73] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243. This article is appended to this evidence as Exhibit AD.

- the majority of investors.[75]

These advantages also make CAPM more intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, as discussed earlier.

I also gave equal weighting to the BYPRP approach which is more widely used than DCF approaches due to its intuitive nature, and because it adjusts for both borrowing rates and risk. Thus the BYPRP approach accounts for interactions between company debt costs and equity markets, and as such I believe it is intuitively sound and hence BYPRP estimates are excellent reflections of existing market conditions.

Based on an equal weighting of the three approaches, I determine the following best estimate for Alberta utility ROEs:

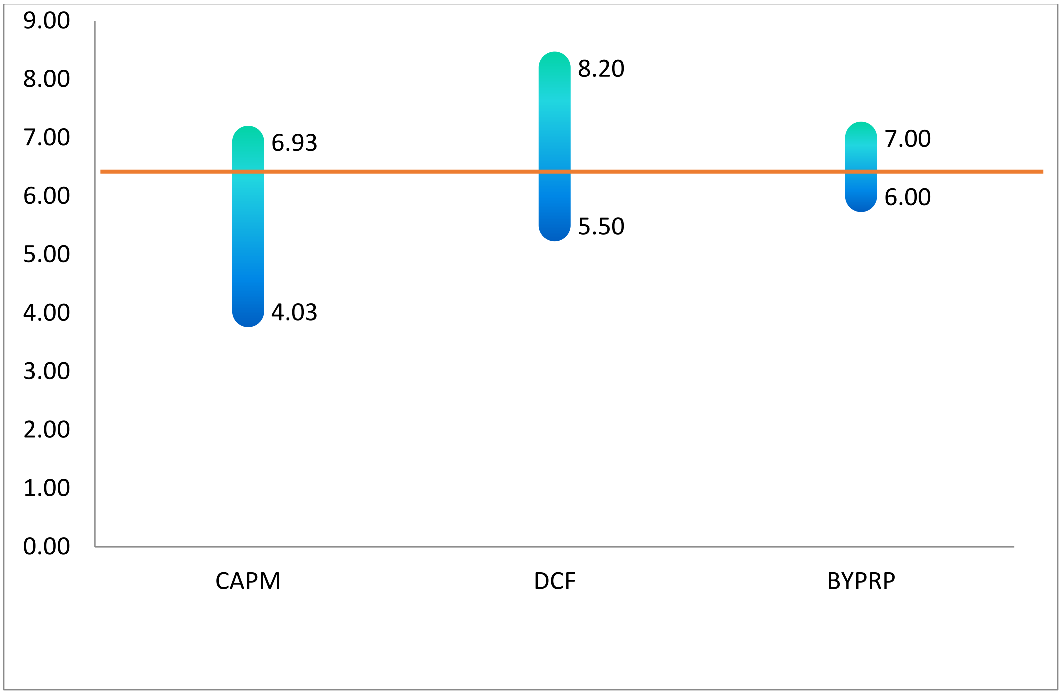
Ke = (1/3)(5.5) + (1/3)(6.9) + (1/3)(6.5) = **6.3%**

This estimate lies centrally in the estimate ranges for the three models, as depicted in Figure 15 below.

[74] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011. This article is appended to this evidence as Exhibit AE.
[75] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32. This article is appended to this evidence as Exhibit AF.

FIGURE 15

ROE ESTIMATE RANGES



This estimate is very reasonable when compared to expected long-term overall stock market returns in the 6-9% and a long-term expected market return of 7.5%, when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 6-9% range are consistent with current long-term forecasts by market professionals and with experienced long-term real stock returns of 5.6-7.4%. The ROE estimate is also consistent with our current low interest rate and low risk environment, which can be expected to change only gradually over the next few years.

4. CAPITAL STRUCTURE ISSUES

4.1. Background

4.1.1. Alberta Utilities' Operating Environment

The utilities provided several debt rating reports during these proceedings, including 16 full reports that applied to Alberta operating utilities - nine from S&P (six – 2017; three -2016), and seven from DBRS (four – 2017; three – 2016). Eight of the nine S&P reports rate the respective utility as "Excellent" with respect to business risk, with the lone exception being the "Strong" business risk rating given to AltaGas for 2017. While DBRS does not provide an explicit business risk rating, four of the seven reports identify "low business risk" as the respective utility's #1 strength. For the other three we can observe: ENMAX's 2017 report suggests the #1 strength is "predictable, steady regulated business with growing earnings;"[76] CU Inc.'s 2017 report states the #1 strength is "low-risk regulated business;"[77] and, AltaGas's 2017 report suggests the top two strengths are "Regulated and fee-based earnings with strong counterparties" and "Stable and diversified operations", respectively.[78] These types of statements echo the sentiment in previous debt rating reports. For example, during the 2016 GCOC Proceeding, all 15 rating reports for the Alberta utilities from calendar year 2015 refer to low business risk as the #1 strength (in the case of DBRS reports) or rated the utilities as Excellent in terms of Business Risk (in the case of S&P reports).[79] Strong regulatory support is generally cited as a contributing factor to this low business risk assessment. For example, S&P stated on page 4 of its January 26, 2017 rating report for AltaLink L.P. that:

> Our view of ALP's business risk largely reflects our opinion of the Alberta Utility Commission's (AUC) regulatory framework that supports stable and predictable cash flow, a key credit strength and ongoing determinant for the ratings.[80]

I concur with these assessments – regulated Alberta operating utilities possess low business risk and enjoy solid regulatory support.

The utilities' experts have argued that the performance-based regulation ("**PBR**") framework has created additional risks for Alberta utilities (as they argued in the 2013 GCOC Proceeding), and that the 2018-2022 PBR framework creates new challenges. Mr. Bell's evidence clearly refutes these arguments. He shows that, since implementation, the return has

[76] Exhibit 22570-X0136, Appendix 3.4, DBRS Credit Rating Report for ENMAX Corporation, PDF page 2.
[77] Exhibit 22570-X0164, ATCO Utilities Credit Rating Reports, PDF page 21.
[78] Exhibit 22570-X0118, AUI MFR – Credit Rating Agency Reports, PDF page 11.
[79] Technically, the Fortis Inc. January 5, 2015 report states that its # 1 strength is "strong and stable dividends from low-risk utilities", which is essentially the same as saying low business risk.
[80] Exhibit 22570-X0151, AML MFR – Equity Analyst and Credit Rating Reports, PDF Page 22.

increased and the standard deviation of returns has decreased during the PBR term for the PBR utilities. In effect, the PBR utilities did better than under cost of service ("**COS**"), and as such, the regulatory risk under PBR is actually less than under COS, resulting in lower business risk for PBR utilities. He also refutes suggestions that the 2018-2022 PBR framework will add significant new risk.

The utilities also argue, as they did in the 2013 GCOC Proceeding and the 2016 GCOC Proceeding, that Decision 2013-417 (the "**UAD Decision**") has created additional risk for Alberta utilities that warrants additional compensation. However, as in the prior proceedings, they do not provide any tangible evidence to support this conjecture. Mr. Bell refutes the entire notion that the utilities should receive compensation for the risk associated with potential losses, while at the same time being in position to realize any gains – it is simply not fair. In other words, in their discussion of the UAD Decision, the utilities do not account for the fact that the UAD Decision also holds the possibility that *gains* will accrue to shareholders, as noted in the 2013 GCOC Decision, where the Commission concluded:

> Therefore, the Commission finds that Ms. McShane's assertion that, "with the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded" is not supported. There is no pattern of gains and losses that would lead to the conclusion that an offsetting upside potential has not been afforded by the *Stores Block* decision. The *Stores Block* decision clearly sets out that both gains and losses on disposition are to the account of the shareholder.
>
> In light of the above considerations, the Commission finds that no adjustment to the allowed ROE or capital structure is warranted for the Alberta Utilities, to account for the application of the principles identified in the UAD decision.[81]

Despite the arguments put forth by the utilities' experts, as noted above, Alberta utilities continue to be rated excellent with respect to business risk by S&P, while low business risk is the #1 strength in DBRS reports. This is what one would expect for mature regulated

[81] Decision 2191-D01-2015, 2013 Generic Cost of Capital, paras. 350-351.

transmission and distribution utilities operating virtual monopolies that are able to pass on legitimate costs to customers. My empirical analysis below confirms that Alberta utilities continue to operate in a low risk environment that enables them to earn above their allowed ROEs with very little volatility in income.

4.1.2. Economic Conditions and Alberta Utilities

Section 2 shows that global economic conditions have stabilized, as have Canadian capital market conditions. Real GDP growth for Alberta is estimated at 6.7% by the CB during 2017, well above average. Growth is expected to moderate to 2.1% in 2018 and 1.6% in 2019. Overall, we can say that the Canadian and Alberta economies are expected to grow at subdued, but healthy levels in the intermediate term. In any event, economic and capital market conditions are far from those existing at the peak of the 2008-2009 financial crisis, and have improved materially for both Alberta and Canadian capital markets since the time of the 2016 GCOC Proceeding.

It is important to note that regulated utilities are not as greatly influenced by economic cyclicality to the extent of traditional businesses. This is true of Alberta utilities. For example, in 2009, real GDP growth in Alberta was -4.1%, yet the average EBIT/Sales ratio for Alberta utilities was 29.1%, slightly above the 2005-2016 average of 28.9% as reported in Table 22, below, while the 2009 average of the individual utility EBIT growth rates was 17.3%, versus the 2005-2016 average of 9.3%. During 2009, the average ROE earned by Alberta utilities was 9.91% as reported in Table 20, which was 91 bp above the allowed ROE of 9.0%. Empirical evidence like this indicates that the earnings of Alberta utilities are resilient in the face of economic decline, which shows they have low business risk. I provide compelling evidence to support this conclusion in Sections 4.2 and 4.3.

4.2. A Quantitative Review of Alberta Utilities' Performance

This section provides a brief review of the performance of the Alberta utilities using information provided for the 2005-2016 period in their Rule 005 reports. Table 19 summarizes the growth in the aggregate figures for the Alberta utilities, excluding EPCOR, over the 2005-2016 period.[82] The working papers for Table 19 are appended as Exhibit N to my evidence.

Table 19 shows that aggregate revenue rose almost three-fold over this period from $1.6 billion to $4.4 billion, representing a compound growth rate of 9.6% per year. By comparison, real GDP growth from 2005-2016 in Alberta demonstrated compound annual growth of 2.2%. Over the same period, EBIT (a commonly used measure of operating income) rose more than threefold, representing an annual compound growth rate of 11.8%. The fact that EBIT grew faster than revenue indicates that regulatory support, including the numerous cost flow-through mechanisms in place, are working effectively and enabling firms to continue to earn solid profit margins on their revenues. This is further attested to by the fact that the EBIT/Sales ratio was 28.3% in 2005 and was even higher by 2016 (35.4%). Finally, we get a similar, if not stronger, message if we look at the figures for net income available to common equity, which grew close to five times the original amount, at an annual compound growth rate of 15.1%. Not surprisingly, the net income margins also increased from 11.0% to 18.9% - very healthy margins indeed. Overall, these figures show that 2005-2016 was a very good 12-year period for regulated Alberta utilities.

TABLE 19

ALBERTA UTILITIES GROWTH STATISTICS (2005-2016)

	Revenue	**EBIT**	**Net Income Available to CE**	**EBIT/Sales**	**NIACE/Sales**
2005	1,604.5	454.7	176.3	28.34%	10.99%
2016	4,389.1	1,554.7	831.4	35.42%	18.94%
Geometric Mean Growth	9.58%	11.83%	15.14%		
Alberta Real GDP Growth (Geometric Mean) 2005-2016[83]	2.18%				

[82] Table 19 includes the reported figures for Alberta utilities excluding EPCOR Distribution and Transmission (due to missing data in their 2005 Rule 005 reports).

[83] Alberta real GDP growth figures for 2005-2016 were obtained from the Conference Board of Canada at: http://www.conferenceboard.ca/hcp/provincial/economy/gdp-growth.aspx (December 30, 2017).

An even more compelling way of reviewing the performance of Alberta utilities is to examine their ability to earn their allowed ROEs on a consistent basis. This is a bottom line measure of the total risks faced by these utilities – “where the rubber hits the road,” so to speak. Table 20 provides such a comparison of the reported ROEs by Alberta utilities in their Rule 005 reports with the allowed ROEs. The yearly average and median figures show that Alberta utilities earned average and median ROEs above the allowed ROE in all years except 2005, when the average reported ROE was a mere 0.18% below the allowed ROE, while the median equalled it. We get a similar message if we look at the weighted average ROE (“**Wt Av ROE”**). This is estimated by weighting each utility according to its average revenue over the entire 2005-2016 period, relative to total revenue across all utilities over the entire period, which effectively gives larger weight to the larger utilities.[84]

[84] The corresponding weights are reported in Table 22.

TABLE 20

ALBERTA UTILITIES REPORTED ROEs (2005-2016)

	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005
Fortis Alberta	9.70%	11.12%	9.77%	9.49%	9.99%	9.73%	9.63%	9.13%	9.19%	8.79%	10.28%	10.45%
ATCO Elec Dist	13.03%	9.90%	9.74%	10.99%	12.14%	11.50%	12.57%	12.62%	10.27%	10.26%	9.38%	9.10%
ATCO Gas	12.93%	11.10%	10.95%	11.86%	11.01%	10.98%	9.67%	11.57%	11.67%	10.83%	8.26%	5.81%
AltaLink	8.21%	8.44%	8.44%	8.77%	9.28%	9.48%	9.10%	9.30%	8.50%	9.20%	9.40%	10.60%
ATCO Pipelines	11.39%	9.80%	10.31%	10.16%	11.16%	11.53%	10.85%	10.88%	9.51%	8.21%	10.61%	10.19%
ATCO Elec Trans	9.14%	8.23%	8.91%	9.84%	10.66%	9.87%	10.21%	9.63%	8.74%	8.50%	9.28%	9.61%
AltaGas	5.83%	6.16%	11.27%	12.50%	10.17%	6.19%	4.86%	8.94%	8.75%	8.51%	8.93%	9.50%
ENMAX Dist	9.93%	6.15%	7.82%	8.05%	10.22%	6.71%	6.79%	10.39%	8.27%	5.08%	6.99%	9.50%
ENMAX Trans	10.33%	11.48%	7.09%	5.90%	0.49%	4.08%	6.61%	12.84%	9.34%	6.58%	10.85%	
EPCOR Dist	8.98%	10.37%	10.31%	9.74%	8.10%	8.03%	10.76%	4.48%	7.81%	9.82%	8.85%	9.16%
EPCOR Trans	6.94%	8.90%	11.59%	7.17%	10.82%	8.36%	9.71%	9.20%	11.12%	10.47%		
Average	9.67%	9.24%	9.65%	9.50%	9.46%	8.77%	9.16%	9.91%	9.38%	8.75%	9.28%	9.32%
Median	9.70%	9.80%	9.77%	9.74%	10.22%	9.48%	9.67%	9.63%	9.19%	8.79%	9.33%	9.50%
Max	13.03%	11.48%	11.59%	12.50%	12.14%	11.53%	12.57%	12.84%	11.67%	10.83%	10.85%	10.60%
Min	5.83%	6.15%	7.09%	5.90%	0.49%	4.08%	4.86%	4.48%	7.81%	5.08%	6.99%	5.81%
StDev	2.25%	1.87%	1.45%	1.96%	3.15%	2.37%	2.23%	2.28%	1.20%	1.72%	1.15%	1.42%
CV(ROE)	0.232	0.202	0.150	0.206	0.333	0.270	0.243	0.230	0.128	0.196	0.124	0.153
Wt Av ROE	10.46%	9.50%	9.73%	10.17%	10.32%	9.69%	9.86%	10.03%	9.52%	9.18%	8.92%	8.70%
Allowed ROEs	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	9.00%	9.00%	8.75%	8.51%	8.93%	9.50%
Diff Avg	**1.37%**	**0.94%**	**1.35%**	**1.20%**	**0.71%**	**0.02%**	**0.16%**	**0.91%**	**0.63%**	**0.24%**	**0.35%**	**-0.18%**
Diff Median	**1.40%**	**1.50%**	**1.47%**	**1.44%**	**1.47%**	**0.73%**	**0.67%**	**0.63%**	**0.44%**	**0.28%**	**0.40%**	**0.00%**
Diff Wt Avg	**2.16%**	**1.20%**	**1.43%**	**1.87%**	**1.57%**	**0.94%**	**0.86%**	**1.03%**	**0.77%**	**0.67%**	**-0.01%**	**-0.80%**

Table 21 provides the summary statistics for each utility over the period and aggregates them. These statistics show that ROEs averaged 9.33% across all utilities and all years, while allowed ROEs averaged 8.70%. The last three rows in this table show that the annual averages of reported ROEs exceeded the allowed ROEs over the 12-year period by 0.64%, with the annual median ROEs exceeding allowed ROEs by a 12-year average of 0.87%. The weighted annual average ROE exceeds the allowed average by an even higher margin of 0.97%, indicating that the larger utilities have been better than average at earning above the allowed ROE. This lends strong support to the evidence provided in Table 19, showing that Alberta utilities operate in a low risk environment that enables them to earn attractive returns

– i.e., since they are consistently able to earn their allowed ROEs or higher. This can be considered the strongest indication that the utilities possess low risk overall. The working papers for Table 20 and Table 21, as well as Table 17, produced above, are appended to this evidence as Exhibit O.

TABLE 21

SUMMARY STATISTICS – ALBERTA REPORTED ROEs (2005-2016)

	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Fortis Alberta	9.77%	9.72%	11.12%	8.79%	0.63%	0.065
ATCO Elec Dist	10.96%	10.63%	13.03%	9.10%	1.38%	0.126
ATCO Gas	10.55%	10.99%	12.93%	5.81%	1.89%	0.179
AltaLink	9.06%	9.15%	10.60%	8.21%	0.65%	0.072
ATCO Pipelines	10.38%	10.46%	11.53%	8.21%	0.92%	0.089
ATCO Elec Trans	9.39%	9.45%	10.66%	8.23%	0.72%	0.077
AltaGas	8.47%	8.84%	12.50%	4.86%	2.32%	0.274
ENMAX Dist	7.99%	7.94%	10.39%	5.08%	1.73%	0.216
ENMAX Trans	7.78%	7.09%	12.84%	0.49%	3.62%	0.466
EPCOR Dist	8.87%	9.07%	10.76%	4.48%	1.69%	0.190
EPCOR Trans	9.43%	9.46%	11.59%	6.94%	1.61%	0.171
Average	9.33%	9.34%	11.63%	6.38%	1.56%	0.175
Median	9.39%	9.45%	11.53%	6.94%	1.61%	0.171
Max	10.96%	10.99%	13.03%	9.10%	3.62%	0.466
Min	7.78%	7.09%	10.39%	0.49%	0.63%	0.065
StDev	1.03%	1.15%	1.02%	2.57%	0.88%	
CV(ROE)						
Wt Av ROE						
	Average	Median	Max	Min	StDev	
Allowed ROEs	8.70%	8.75%	9.50%	8.30%	0.38%	
Diff Avg	**0.64%**	**0.67%**	**1.37%**	**-0.18%**	**0.53%**	
Diff Median	**0.87%**	**0.70%**	**1.50%**	**0.00%**	**0.55%**	
Diff Wt Avg	**0.97%**	**0.99%**	**2.16%**	**-0.80%**	**0.80%**	

4.3. A Quantitative Assessment of Alberta Utilities' Risk

4.3.1. Business Risk

My examination of the Alberta utilities' operating and regulatory environment above suggests they possess low business risk. The same can likely be said for most other Canadian regulated utilities that operate in supportive regulatory environments. Certainly, it is easy to see that such regulated utilities have very low business risk when compared to companies operating in other non-regulated industries that face greater demand variability, greater competition, and that do not have as great of an ability to flow through increases in their costs to their customers. As noted in Section 4.1, debt rating reports consistently suggest that the Alberta utilities have low business risk.

Most experts assessing "business risk" would agree that it refers to some variation of factors that cause uncertainty, or volatility, in operating income. For example, the following definition of business risk can be found in the CFA Institute's on-line Glossary of definitions: "The risk associated with operating earnings. Operating earnings are uncertain because total revenues and many of the expenditures contributed to produce those revenues are uncertain" This definition is consistent with the definition of business risk proposed by Dr. Roger Morin in the 2003 Newfoundland and Labrador Board of Commissioners of Public Utilities ("**PUB**") rate hearings, as noted in Order No. P.U. 19 (2003), quoted below:

> **<u>Business Risk</u>**
>
> Refers to the relative **variability of operating profits** induced by the external forces of demand for and supply of the firm's products, by the presence of fixed costs, by the extent of diversification or lack thereof of services, and by the character of regulation.[85]

This definition was accepted by the PUB at that time:

> The Board feels the above definitions are consistent and reasonable. The Board accepts these definitions and sees no particular conflict in terms of the evidence presented during the hearing.[86]

Similarly, during the 2016 GCOC Proceeding, in response to AML/EDTI-UCA-2016FEB-011,[87] Mr. Hevert confirmed that he was referring to "operating earnings" in the following passage from his evidence in the 2016 GCOC Proceeding discussing business risk:

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[85] Order No. P.U. 19 (2003), In the Matter of the 2003 General Rate Application filed by Newfoundland Power, page 31, source: http://www.pub.nl.ca/nfpower03/order/pu19-2003.pdf
[86] *Ibid.*

> Business risk reflects the uncertainty associated with owning the subject company's common stock, without the use of debt and/or preferred capital. Examples of the business risks generally faced by utilities include, but are not limited to, the regulatory environment, customer mix and concentration, service territory economic growth, capital intensity and size, and the degree of operating leverage, all of which have a direct bearing on earnings.[88]

In this section, I use a variation of a commonly used measure of operating income volatility, the coefficient of variation of the EBIT/Sales ratio (hereafter "**CV(EBIT/Sales)**"), to *quantify* a firm's level of business risk.[89] The CV is determined by dividing the standard deviation ("**SD**") of the EBIT/Sales ratio by the average EBIT/Sales level. The rationale for using the CV as a measure of EBIT/Sales volatility, rather than simply using the SD of EBIT/Sales, is that the SD is affected by the size of the average EBIT/Sales ratio. In other words, firms with larger EBIT/Sales ratios would have higher SDs of EBIT/Sales, even if they have less volatility, simply because the level of the EBIT/Sales figures used to determine the SD are higher. This is indeed the case in my analysis – for example, the average EBIT/Sales ratio across the Alberta utilities over this period is 28.9%, much higher than the U.S. utility sample average of only 15.9%.[90] The CV is more appropriate in such instances and is commonly used to measure volatility since it effectively "scales" the SD of EBIT/Sales when it is divided by the average level of EBIT/Sales.

This measure (i.e., CV(EBIT/Sales)) is calculated as the standard deviation of the EBIT/Sales ratio (2005-2016) divided by the average of the EBIT/Sales ratio over this period. Using the EBIT/Sales ratio rather than the level of EBIT is a valid measure of business risk, since it measures volatility in the operating profit margins for firms. It also has the advantage that, as a ratio, the expected value and past average values will often coincide since these profitability margins often tend to gravitate to some long-term average.

[87] Exhibit 20622-X0164, Information Response to AML/EDTI-UCA-2016FEB-011.
[88] Exhibit 20622-X0082, AML Evidence of Robert Hevert, page 16, lines 13-17.
[89] For example, the 2013 CFA curriculum (Reading 28, page 351) refers to the use of CV(EBIT) as a measure of business risk, as do numerous finance and accounting texts such as Financial Management: Principles and Applications, 6th edition, by J. William Petty, Sheridan Titman, Arthur J. Keown, Peter Martin, John D. Martin, Michael Burrow, Hoa Nguyen, 2011, Pearson Higher Education.
[90] The fact that the U.S. utilities have a much lower average EBIT/Sales ratio in and of itself also indicates the U.S. utilities have higher business risk.

4.3.2. Alberta Utilities

Table 22 provides the CV(EBIT/Sales) ratios for the Alberta utilities over the 2005-2016 period. The average CV across all utilities is 0.154, while the median is 0.132 and the weighted average is 0.133. Most of the individual utility CV estimates fall between 0.10 and 0.15, with the exception of ATCO Pipelines, which has a CV of 0.057, and AltaGas and ENMAX Transmission, which have CVs of 0.376 and 0.250 respectively. Since these three utilities have relatively low weighting according to average revenue, the median and weighted average CV estimate is lower at 0.133. Table 22 also provides summary statistics for EBIT/Sales and EBIT growth for the Alberta utilities, which confirm the two points made earlier with respect to the discussion of the results reported in Table 19. Namely, the Alberta utilities have very healthy operating profit margins as measured by EBIT/Sales with average, median and weighted average figures of 28.9%, 27.1% and 29.0% respectively. They have also displayed substantial growth in EBIT over this decade with utility median growth rates across all utilities producing average, median and weighted averages of 9.3%, 9.1% and 10.4% respectively. The working papers for Table 22 are appended as Exhibit N to my evidence.

TABLE 22

CV(EBIT/SALES) ESTIMATES – ALBERTA UTILITIES (2005-2016)

	Weights (based on Average Revenue – 2005-2016)	**CV (EBIT/Sales)**	**EBIT/Sales**	**EBIT Growth(median)**
Fortis Alberta	11.3%	0.132	0.338	0.120
ATCO Elec Dist	17.0%	0.145	0.189	0.067
ATCO Gas	17.3%	0.098	0.255	0.098
AltaLink	12.6%	0.119	0.443	0.149
ATCO Pipelines	6.0%	0.057	0.387	0.053
ATCO Elec Trans	11.2%	0.147	0.468	0.199
AltaGas	3.6%	0.376	0.101	0.087
ENMAX Dist	7.7%	0.145	0.191	0.041
ENMAX Trans	1.5%	0.250	0.271	0.015
EPCOR Dist	9.7%	0.107	0.140	0.091
EPCOR Trans	2.1%	0.116	0.393	0.106
Alberta Utilities		**CV (EBIT/Sales)**	**EBIT/Sales**	**EBIT Growth(median)**
Average		**0.154**	**0.289**	**0.093**

Median	**0.132**	**0.271**	**0.091**
Max	0.376	0.468	0.199
Min	0.057	0.101	0.015
StdDev	0.088	0.125	0.051
Weighted Average	**0.133**	**0.290**	**0.104**

4.3.3. Comparing the Risk of Alberta Utilities to U.S. Utilities

The purpose of the analysis in this section is to provide quantitative evidence comparing the business risk of U.S. utilities used in the utilities' experts' evidence to that of the Alberta utilities. In particular, the evidence provided by the utilities relies heavily on U.S. samples based on the premise that such samples are of comparable risk to Alberta utilities, and therefore require no adjustments for comparison purposes. Therefore, in order to avoid debate over my U.S. sample selection during the 2016 GCOC Proceeding, I used the same U.S. utilities for comparison purposes as those used by Dr. Villadsen and Mr. Hevert respectively. At that time, I was able to find the required data for 37 of the 38 total firms used by either Dr. Villadsen and/or Mr. Hevert.[91] For the current proceeding, I cross-referenced these 37 utilities with the samples used by Dr. Villadsen, Mr. Hevert and Mr. Coyne, and only included firms that were in at least one of their samples. This left me with 32 U.S. utilities. This sample includes 18 of the 21 U.S. Electric Utility firms that Dr. Villadsen classified as regulated, 7 of the 9 U.S. Electric Utilities she classified as partially regulated, and 6 of the 9 utilities in her U.S. Gas sample – i.e., 31 of the 39 firms (i.e., 80%) she uses in these samples. It also includes 19 of the 25 U.S. utilities (i.e., 76%) used by Mr. Hevert, and 7 of the 11 U.S. utilities (i.e., 64%) used by Mr. Coyne. Hence it is a reasonable depiction of the U.S. utilities used by the utilities' experts.

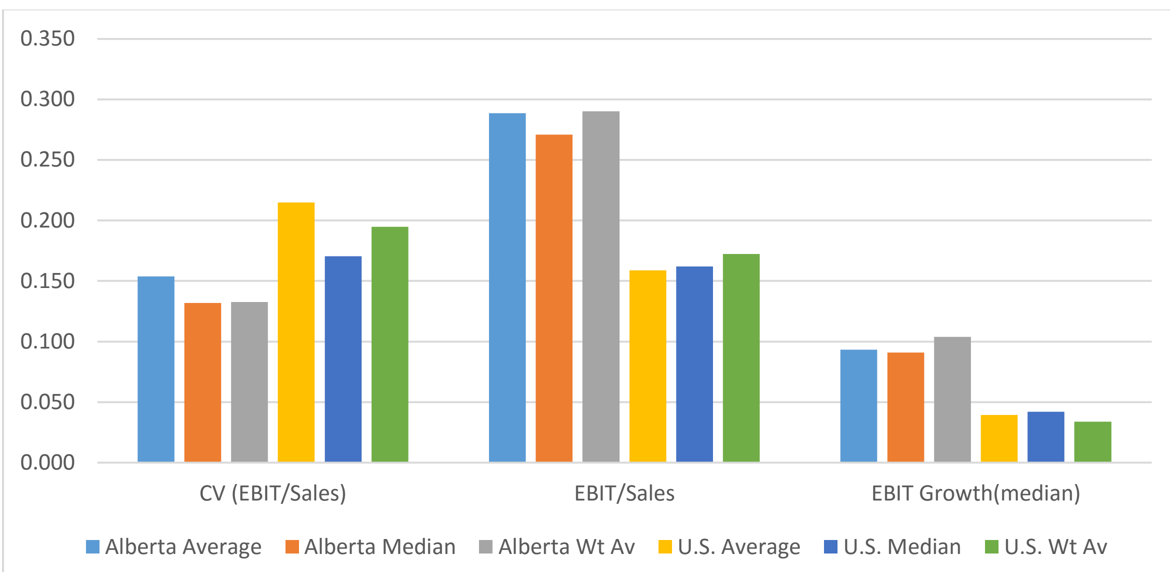
Figure 16 depicts a summary of the main results of this analysis. The evidence clearly shows that U.S. utilities have higher volatility in their EBIT/Sales ratios as measured by the CV(EBIT/Sales). The U.S. average, median and weighted average values for the CV(EBIT/Sales) are 0.215, 0.171 and 0.195 respectively, versus corresponding figures of 0.154, 0.132 and 0.133 for Alberta utilities. These figures show that the U.S. utilities in this sample display greater volatility in operating profit margins, as measured by EBIT/Sales. In

[91] There was some overlap in the chosen utilities, with 18 of the utilities being included in both of their U.S. proxy groups.

addition, Figure 16 shows clearly that the Alberta utilities have much higher operating profit margins with average, median and weighted average EBIT/Sales ratios of 0.289, 0.271 and 0.290 versus corresponding U.S. figures of 0.159, 0.162 and 0.172. Finally, the last bar chart in Figure 16 shows that the median annual percentage EBIT growth was also much higher for the Alberta utilities with average, median and weighted average figures of 9.3%, 9.1% and 10.4% versus corresponding U.S. figures of 3.9%, 4.2% and 3.4%. So overall, Figure 16 shows that Alberta utilities have less volatility in operating profit margins, which demonstrates lower business risk, while at the same time maintaining higher profit margins and higher growth in EBIT levels. This evidence shows clearly that the Alberta utilities have lower business risk than their U.S. counterparts in this sample. The working papers for Figure 16 are appended as Exhibit N (Alberta utilities), Exhibit P (U.S. utilities) and Exhibit Q (summary statistics) to my evidence.

FIGURE 16

ALBERTA VERSUS U.S. UTILITIES (2005-2016)



Data Source: Alberta data are obtained from the Rule 005 reports;
U.S. data are obtained from the Compustat database.

Table 23 provides the individual results for the U.S. utilities, confirming that the patterns displayed in Figure 16 are not driven by the use of averages or medians. In particular, I would note that only 8 of the 32 CV estimates for the U.S. utilities is below the median

Alberta CV estimate of 0.132, with the remaining 24 CV estimates being above this level, some being much higher. None of the individual U.S. utility EBIT/Sales average ratios is higher than the Alberta median figure of 27.1%, and only 1 of the 32 median EBIT growth figures is as high as the median growth figure of 9.1% for the Alberta utilities. So, the conclusions that the U.S. utilities display greater operating income volatility, despite lower EBIT margins and growth in EBIT, stands firmly. The working papers for Table 23 are appended as Exhibit P to my evidence.

TABLE 23

CV(EBIT/SALES) ESTIMATES – U.S. UTILITIES (2005-2016)

	CV (EBIT/Sales)	EBIT/Sales	EBIT Growth (median)
ALLETE INC	0.069	0.160	0.035
ALLIANT ENERGY CORP	0.131	0.156	0.037
AMEREN CORP	0.094	0.195	0.048
AMERICAN ELECTRIC POWER CO	0.083	0.192	0.057
ATMOS ENERGY CORP	0.385	0.108	0.057
CENTERPOINT ENERGY INC	0.170	0.127	0.028
CMS ENERGY CORP	0.772	0.112	0.017
CONSOLIDATED EDISON INC	0.167	0.163	0.056
DOMINION RESOURCES INC	0.213	0.237	-0.003
DTE ENERGY CO	0.203	0.130	-0.028
EDISON INTERNATIONAL	0.056	0.184	0.022
EL PASO ELECTRIC CO	0.165	0.172	0.071
ENTERGY CORP	0.118	0.175	-0.009
FIRSTENERGY CORP	0.235	0.167	0.056
IDACORP INC	0.124	0.196	0.068
MGE ENERGY INC	0.202	0.185	0.059
NEW JERSEY RESOURCES CORP	0.374	0.054	0.088
NEXTERA ENERGY INC	0.250	0.204	0.060
NORTHWEST NATURAL GAS CO	0.139	0.169	-0.001
NORTHWESTERN CORP	0.203	0.148	0.041
OGE ENERGY CORP	0.323	0.161	0.043
OTTER TAIL CORP	0.385	0.090	0.030
PG&E CORP	0.078	0.167	0.017
PINNACLE WEST CAPITAL CORP	0.157	0.216	0.002
PNM RESOURCES INC	0.457	0.144	0.030
PORTLAND GENERAL ELECTRIC CO	0.155	0.146	0.055
PUBLIC SERVICE ENTRP GRP INC	0.157	0.234	0.024
SCANA CORP	0.289	0.178	0.067
SOUTH JERSEY INDUSTRIES INC	0.171	0.143	0.048
SOUTHWEST GAS CORP	0.143	0.118	0.037
WGL HOLDINGS INC	0.230	0.094	0.091
XCEL ENERGY INC	0.181	0.156	0.056
	CV (EBIT/Sales)	**EBIT/Sales**	**EBIT Growth**
Average	**0.215**	**0.159**	**0.039**
Median	**0.171**	**0.162**	**0.042**
Max	0.772	0.237	0.091

Min	0.056	0.054	-0.028
StdDev	0.142	0.041	0.028
Weighted Average	**0.195**	**0.172**	**0.034**

While this sample of U.S. utilities may not be high business risk firms relative to firms in other industries, they clearly have more business risk than their Alberta counterparts. Since total risk is comprised of both business and financial risk, it is a basic tenet of finance that firms with lower business risk can assume greater financial risk, and vice versa. This may explain some of the rationale for U.S. regulators providing for higher average allowed ROEs and equity ratios than their Canadian counterparts, although I cannot say for sure, since I have not examined the rationale provided for recent U.S. regulatory decisions.

One effective way to compare overall riskiness of Alberta utilities to their U.S. counterparts would be to compare their ability to earn their allowed ROEs, as I did for the Alberta utilities in Tables 20 and 21. Recall that Alberta utilities earned ROEs above the allowed ROEs on average every year from 2006-2016, and that over the entire 2005-2016 period earned ROEs exceeded allowed ROEs by an annual average (median) of 0.64% (0.87%) with a revenue-weighted annual average of 0.97%. Unfortunately, it is not practical to compare the earned ROEs to allowed ROEs for the U.S. utilities because the U.S. utilities included in the U.S. proxy groups are primarily holding companies that own several distinct operating utilities, which operate in numerous jurisdictions.

Another effective way of comparing the riskiness of Alberta utilities to that of the U.S. utility proxy groups is to compare the volatility in earned ROEs. This is a measure of total risk (i.e., business and financial risk), since financial leverage influences net income, whereas EBIT is not influenced directly by financial leverage. Table 24 provides the summary statistics for earned ROEs for the U.S. sample, identical to those provided for the Alberta utilities in Table 21. Table 24 shows that the reported ROEs are higher for the U.S. utilities on average, with an average across all 32 utility averages of 9.77%, versus the corresponding figure of 9.33% across the Alberta utilities. This is expected, since allowed ROEs in the U.S. have been higher than in Canada over the several years. However, if we look at the last column in Table 24 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the U.S. firms to the results in the last column of Table 21 for Alberta utilities, we can see that the

U.S. utilities displayed much greater volatility in ROEs than the Alberta utilities. In particular, the average and median CV(ROE) figures across all of the U.S. utilities were 0.413 and 0.236 respectively, versus corresponding figures of 0.175 and 0.171 for Alberta utilities as reported in Table 21. The working papers for Table 24 are appended to my evidence as Exhibit R.

TABLE 24

SUMMARY STATISTICS – U.S. REPORTED ROEs (2005-2016)

	Average	Median	Max	Min	StDev	CV(ROE)
ALLETE INC	8.43%	7.94%	11.80%	6.56%	1.46%	0.174
ALLIANT ENERGY CORP	10.73%	10.70%	16.56%	4.68%	2.84%	0.265
AMEREN CORP	5.10%	8.26%	9.32%	-14.72%	7.39%	1.449
AMERICAN ELECTRIC POWER CO	9.84%	10.03%	13.27%	3.51%	2.77%	0.281
ATMOS ENERGY CORP	9.28%	9.30%	10.11%	8.57%	0.48%	0.052
CENTERPOINT ENERGY INC	12.69%	13.63%	32.14%	-19.99%	13.59%	1.072
CMS ENERGY CORP	10.11%	12.57%	13.71%	-10.00%	7.20%	0.712
CONSOLIDATED EDISON INC	9.46%	9.10%	12.45%	8.58%	1.18%	0.125
DOMINION RESOURCES INC	15.10%	14.56%	27.16%	2.86%	6.75%	0.447
DTE ENERGY CO	9.91%	9.24%	16.59%	8.27%	2.50%	0.253
EDISON INTERNATIONAL	9.55%	11.08%	15.73%	-0.98%	5.59%	0.585
EL PASO ELECTRIC CO	10.44%	10.20%	13.62%	8.06%	1.73%	0.166
ENTERGY CORP	9.30%	12.06%	15.57%	-6.98%	7.84%	0.843
FIRSTENERGY CORP	8.27%	6.66%	16.20%	2.41%	4.98%	0.602
IDACORP INC	9.07%	9.39%	10.06%	6.82%	1.06%	0.117
MGE ENERGY INC	11.09%	11.05%	12.18%	10.16%	0.69%	0.062
NEW JERSEY RESOURCES CORP	12.57%	12.99%	16.35%	3.95%	3.73%	0.297
NEXTERA ENERGY INC	12.41%	12.30%	14.03%	10.58%	0.94%	0.076
NORTHWEST NATURAL GAS CO	9.21%	8.55%	12.53%	6.88%	2.01%	0.218
NORTHWESTERN CORP	9.19%	9.38%	10.77%	6.46%	1.22%	0.133
OGE ENERGY CORP	12.14%	12.71%	14.53%	8.16%	1.83%	0.151
OTTER TAIL CORP	5.45%	7.24%	10.30%	-2.32%	5.08%	0.931
PG&E CORP	8.95%	8.53%	14.27%	5.36%	2.99%	0.334
PINNACLE WEST CAPITAL CORP	8.33%	9.15%	9.68%	2.06%	2.34%	0.280
PNM RESOURCES INC	3.13%	6.32%	11.24%	-16.41%	7.88%	2.514
PORTLAND GENERAL ELECTRIC CO	7.92%	8.01%	11.02%	5.77%	1.57%	0.198
PUBLIC SERVICE ENTRP GRP INC	13.73%	13.74%	18.34%	6.76%	3.56%	0.259
SCANA CORP	10.83%	10.43%	13.71%	9.95%	1.13%	0.104
SOUTH JERSEY INDUSTRIES INC	11.66%	11.19%	14.93%	9.22%	1.94%	0.167

SOUTHWEST GAS CORP	8.81%	9.02%	10.27%	5.87%	1.26%	0.143
WGL HOLDINGS INC	10.20%	10.88%	12.28%	6.40%	1.69%	0.165
XCEL ENERGY INC	9.66%	9.63%	10.20%	9.16%	0.42%	0.043
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**9.77%**	**10.18%**	14.09%	2.99%	3.36%	**0.413**
Median	**9.61%**	**9.83%**	13.44%	6.14%	2.17%	**0.236**
Max	**15.10%**	**14.56%**	32.14%	10.58%	13.59%	2.514
Min	**3.13%**	**6.32%**	9.32%	-19.99%	0.42%	0.043
StDev	**2.40%**	**2.10%**	4.78%	8.06%	2.97%	0.507

The ROE analysis above, similar to the analysis of CV(EBIT/Sales), suggests that the U.S. utilities possess greater risk than Alberta utilities. This is hardly surprising given that the U.S. sample is comprised of holding companies with various ownership structures and a variety of exposures to risks (including significant generation risks) to which Alberta transmission and distribution operating utilities are not – at least not to the same extent.

Clearly many of the utilities in the U.S. sample are distinct from Alberta operating utilities in terms of the risk they face. This is obvious from my discussion of beta estimation in Appendix B, which addresses Mr. Hevert's historical evidence of Canadian and U.S. utility beta estimates. Charts 22 and 23 of Mr. Hevert's evidence show that U.S. utility beta estimates have consistently exceeded those of Canadian utilities, with long-term averages of 0.51 and 0.43, which are 34.2% and 26.5% higher than the corresponding Canadian weekly and monthly average estimates of 0.38 and 0.34. In fact however, this difference in Canada-U.S. beta estimates understates the true difference in risk, since the estimated betas are "levered" betas (i.e., they do not adjust for differences in the leverage ratios of the companies used to estimate them). The reason this is misleading is because U.S. utilities display higher levered betas, despite the fact they should be expected to have lower leverage ratios on average (i.e., since U.S. utilities have higher allowed equity ratios). Hence, we would expect them to have lower betas than their Canadian counterparts if they had the same level of business risk. The opposite finding provides strong evidence that U.S. utilities possess *greater* business risk than Canadian utilities, since they have lower financial leverage (and hence lower financial risk) on average than Canadian utilities. Appendix B shows that the true *comparable* U.S. beta historical averages of 0.61 (monthly) and 0.72 (weekly) are almost double the comparable Canadian beta estimates of 0.34 and 0.38, after accounting for leverage differences.

Given such evidence, it is also not surprising that 17 of the 30 utilities included in Dr. Villadsen's U.S. Electric sample are rated in the BBB category (as well as 2 out of 9 utilities in her U.S. Gas sample). 14 of 25 utilities in Mr. Hevert's U.S. sample also fall in the BBB category, as do 3 of the 11 utilities in Mr. Coyne's U.S. sample. As mentioned, there is overlap in some of the firms in the utilities' experts' U.S. samples, and the net result is that 18 of the 32 firms examined in my U.S. sample in Tables 23 and 24 above have debt ratings in the BBB category. It is hardly surprising that my results above confirm that Alberta utilities possess lower risk than the U.S. utilities, as measured by lower volatility in operating income and ROE. As a result, I do not use U.S. samples in my analysis, since they are not good comparators in terms of the risks they possess.

4.3.4. Conclusions About Alberta Utilities' Risk Versus Comparables

The discussion above shows that U.S. holding companies are poor comparators for regulated Alberta utilities, since 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. Given the significant issues with using U.S. comparables, I have used only Canadian utilities in both my CAPM and DCF analysis, while recognizing their limitations. In particular, while using Canadian utilities is better than using U.S. utilities, they are also imperfect comparators, since public information is generally only available for holding companies and not for operating companies. Given the comparability issues involved, I note that I focused on the use of averages, index betas and long-term average Canadian utility beta estimates in arriving at a final beta estimate. Similarly, I used averages across the utilities in my DCF analyses to try and mitigate potential comparability issues, and more importantly I use my market DCF estimates (which I consider to be more reliable) as a reasonableness check on the results.

The most important conclusion that arises from my analysis in Sections 4.1-4.3 is that regulated Alberta utilities possess very low business risk. My quantitative analysis in

Sections 4.2 and 4.3 confirms this fact, which supports Mr. Bell's conclusions and reflects the long-standing business risk assessment of Alberta utilities by debt rating agencies.

4.4. Financial Risk and Credit Metrics

Section 4.3 shows that Alberta utilities have earned ROEs at or above their allowed ROEs for the last 11 years – exceeding them by an annual average of 0.64% (weighted average of 0.97%). They have done so with very low volatility in these earned ROEs. These facts suggest that they possess low total risk, which is a function of both business risk and financial risk.

The allowed equity ratios ("**ERs**") in the 2016 GCOC Decision were 37% for all of the utilities, with the exception of the ER of 41% for AltaGas. Mr. Bell's evidence shows that the EBIT coverage ratio, the FFO coverage ratio and the FFO/Debt ratios associated with an ER of 37% and at the existing ROE of 8.5% would be 2.39, 3.58 and 12.00% respectively. These ratios exceed the AUC's thresholds of 2.0, 3.0 and 11.1%-14.3%, respectively, very comfortably. Appendix B of Mr. Bell's evidence further shows that the metrics for Alberta utilities would exceed the minimum AUC values if the ER was maintained at 37%, while the allowed ROE was reduced to 7.5% - with EBIT coverage of 2.23, FFO coverage of 3.45 and FFO/Debt of 11.44%.

Given my conclusions regarding the low risk possessed by Alberta utilities, the metric analysis above shows that the AUC can comfortably reduce the allowed ROE in combination with the existing equity ratio of 37%,[92] and maintain the financial integrity of the utilities.

4.5. Capital Structure Recommendation

The utilities' evidence argues that Alberta utilities possess similar risk to their U.S. and Canadian utility samples, but may in fact be higher. I strongly disagree with such statements for several reasons. First, my empirical analysis provides strong evidence that Alberta utilities have much less risk than the U.S. utilities groups presented in the utilities' evidence. This is consistent with the higher betas displayed by U.S. utilities historically, despite the fact

[92] This is also true for an ER of 36%, which is ENMAX's current allowed ER according to Mr. Coyne's evidence (i.e., refer to Exhibit 22570-X0131, page 113 or PDF 114).

they have lower leverage ratios. It is also consistent with the high proportion of utilities rated below A in the U.S. samples.

My analysis shows that Alberta utilities possess low risk as shown by their low earnings volatility, their ability to generate high operating profit margins, and their ability to grow operating earnings. Given this low risk, it is not surprising that they have been able to generate ROEs above the allowed ROEs for the last 11 years consecutively, and that these earned ROEs have displayed low volatility. My analysis of the global, Canadian and Alberta economies suggests that economic and capital market conditions are stable and have improved since the time of the 2016 GCOC Proceeding. I recommend that the Commission maintain existing allowed equity ratios, in combination with my recommended reduction in the allowed ROE. My risk analysis suggests this is a reasonable approach, and the credit metric analysis provided by Mr. Bell supports this position.

5. ROEs AND CAPITAL STRUCTURE

One way to illustrate the relationship between ROE and equity ratios is to use the DuPont system for decomposing ROE into basic components. The standard 3-point decomposition formula breaks ROE into three financial ratios which are considered important by analysts examining company performance. These ratios are: the net income margin (net income dividend by sales, or "**NI/S**"); the asset turnover ratio (total sales divided by total assets, or "**S/TA**"); and, the leverage ratio (total assets divided by total equity, or "**A/E**"). Since ROE is defined as net income divided by total equity (or "**NI/E**"), we can see the multiplying the three ratios above by one another leaves us with NI/E or ROE. This equation is presented below:

$$ROE = NI/S \times S/A \times A/E$$

Since the product of the first two terms reduces to NI/A, or the return on assets ("**ROA**"), it is also common to observe that ROE = ROA × A/E, which is convenient for my discussion.

I begin by noting that a higher leverage ratio (A/E) implies a lower equity ratio, and vice-versa. Non-regulated firms will typically try to choose a leverage ratio that generates higher ROEs, while recognizing that higher leverage ratios generate additional financial risk, as reflected in greater volatility in ROEs, all else being equal. However, regulated utilities earn higher NI if they have a higher ER (i.e., lower A/E) since they earn the allowed ROE on this higher equity dollar figure. Of course they should also earn higher ROEs if they are awarded higher allowed ROEs. So regulated utilities prefer both higher allowed ROEs and higher ERs. Not only do the utilities earn higher net income if they have higher allowed ERs, it also reduces their financial risk and the associated volatility in ROEs, all else being equal. Of course, this additional net income and reduction in earnings volatility comes at the expense of consumers, as reflected in their rates.

I would note that my analysis in Section 3 shows that Alberta utilities have low business risk, as reflected by volatility in operating income, and that they also maintain low total risk as reflected in both their ability to earned allowed ROEs and the low volatility in those earned ROEs. As Mr. Stauft mentioned in his evidence in the 2016 GCOC Proceeding, the holding companies of many of the Alberta regulated utilities maintain equity ratios at the holding company level that are lower than at the regulated operating company level.[93] This makes sense to me since they can increase their earned ROEs by doing so (as long as ROA remains positive), as long as they are comfortable with the additional volatility in ROE. Given the low volatility in both operating income and earned ROEs that I have noted, it seems reasonable that additional volatility is not problematic.

The discussion above supports the notion that the AUC approach of setting one allowable ROE for utilities and then adjusting the allowed ERs to vary according to risk levels relative to the "average" utility is a logical approach. The granting of higher ERs to utilities deemed to have greater business risk appropriately reduces the financial risk of such utilities. Since total risk is a function of both business and financial risk, such a process is a useful mechanism for controlling total risk.

This concludes my testimony.

[93] See Exhibit 20622-X0303, Evidence of Mark Stauft, pages 9-12. For example, Mr. Stauft noted at that time that Canadian Utilities Ltd. had an equity ratio of 32%, Fortis Inc. had an equity ratio of 36%, and AltaLink Investments had a consolidated common equity ratio of about 27%.

TAB 3

Alberta Utilities Commission

November 10, 2022

Proceeding 27084, Determination of the Cost-of Capital Parameters in 2024 and Beyond

Appendix A – Finalized screening criteria

- Utilities with nuclear assets from the comparator group are permitted as long as their nuclear assets represent no more than 25 per cent of the utility's total regulated generation.
- Utilities that announced mergers and acquisitions in excess of 25 per cent of their market capitalization during the six months prior to February 1, 2023, are excluded.
- Utilities are excluded from the comparator group if less than 80 per cent of their assets are associated with rate regulated activities regardless of whether those assets consist solely of electric utility operations, natural gas utility operations or a combination of both.
- For the following two criteria, consensus was reached on a company-by-company basis at the technical conference:
  - Exclusion of companies where less than 80 per cent of their assets are associated with rate regulated utility activities.
  - Exclusion of companies where less than 75 per cent of their operating income is from rate regulated utility operations.
- Companies that are not publicly traded are excluded from the comparator group.
- Utilities that do not have a BBB+ equivalent corporate credit rating from one of the following credit rating agencies are excluded from the comparator group: BBB+ from S&P Global Ratings; Baa1 from Moody's Investor Service; BBB (high) from Morningstar/DBRS; or BBB+ from Fitch Ratings. In the event the holding company does not have a credit rating, the credit rating of an operating company is adopted.
- Utilities that do not have two or more sources of data from recognized and reputable third-party data providers, such as Thomson Reuters, Bloomberg, S&P Capital IQ/S&P Global, and Morningstar/DBRS, are excluded from the comparator group.
- Water utilities are excluded from the comparator group.
- The following publicly traded Canadian utility holding companies are included in the comparator group, regardless of the screening criteria:
  - Algonquin Power & Utilities Corp.
  - Canadian Utilities Ltd.
  - Emera Inc.
  - Fortis Inc.
  - Hydro One Ltd.
- TC Energy Corporation and Enbridge Inc. are excluded from the comparator group.
- OGE Energy, Allete and Northwestern Corp. are included in the comparator group.

TAB 4

06-Sep-2023 | 10:00 EDT

Enbridge Inc. Outlook Revised To Negative On Announced Acquisition Of Natural Gas Utilities; 'BBB+' Rating Affirmed

- On Sept. 5, 2023, Enbridge Inc. announced it entered into definitive agreements with Dominion Energy Inc. to acquire The East Ohio Gas Co. (EOG), Questar Gas Co., and Public Service Co. of North Carolina, Inc. (PSNC).
- The aggregate purchase price of approximately US$14 billion consists of US$9.4 billion in cash consideration and US$4.6 billion of assumed debt. The company has also announced a C$4 billion underwritten equity offering to fund part of the cash consideration.
- The acquisition creates North America's largest natural gas utility platform and further enhances the company's business risk profile. Based on our assumed funding plan, we forecast debt-to-EBITDA will be 4.9x in 2024.
- S&P Global Ratings revised its outlook on Enbridge to negative from stable and affirmed its ratings on the company, including its 'BBB+' issuer credit rating.
- The negative outlook reflects uncertainty about the nature and timing of the remainder of the financing plan and credit metrics, which leave limited cushion to the company's downgrade trigger of at or above 5x debt to EBITDA.

TORONTO (S&P Global Ratings) Sept. 6, 2023--S&P Global Ratings today took the rating actions listed above. We believe the addition of the regulated utilities enhances Enbridge's business risk profile. The acquisition will increase the percentage of EBITDA from Enbridge's regulated utilities to approximately 25%. Enbridge's existing utility platform delivers service to about 15 million customers in Ontario and Quebec through 3.9 million residential, commercial, institutional, and industrial meter connections, and distributes more than 5.9 billion cubic feet per day of natural gas, based on 2022 figures. Combining EOG, Questar, and PSNC in this platform will add 3.0 million customers (EOG: 1.2 million; Questar: 1.2 million; PSNC: 600,000), totaling 6.9 million connections post transaction. These customers will be spread across five states and two provinces, further diversifying the company's platform. We currently assess Enbridge's business risk as excellent, based on the strong contractual framework that underpins the company's liquids business and current regulated gas utility business. However, we believe the purchase of the utilities further strengthens its competitive positioning. Consequently, we have applied a positive comparable rating modifier.

Although we believe Enbridge has superior market access, funding plan execution risk remains in the short-to-medium term. The transaction consists of approximately US$14 billion that will be funded through cash consideration. Concurrent with its acquisition announcement, Enbridge also announced a C$4 billion underwritten equity offering. As a result, there is approximately US$6.5 billion to be funded before close in 2024. The company has indicated it will rely on a number of avenues to fund the remainder of the purchase price including noncore asset sales, hybrid capital, dividend reinvestment plan, at-the-market program, and debt. Although Enbridge has superior market access, given a significant portion of the cash consideration still requires funding, we believe that execution risk remains in the short-to-medium term.

Although historically we have considered financial metrics on a funds from operations (FFO)-to-debt basis, we believe that using debt to EBITDA to measure leverage better aligns the company with its peer group, which is primarily located in the U.S. and is evaluated on a debt-to-EBITDA basis. This is particularly the case, given the amount of revenue that Enbridge receives from its U.S. assets. Based on our assumed funding plan, we forecast debt to EBITDA will be 4.9x in 2024. Although the company has reiterated its commitment to debt to EBITDA of 4.5x-5.0x, a metric of 4.9x leaves limited cushion for Enbridge to execute its funding plan without relying on more than our assumed proportion of debt.

The negative outlook reflects the potential for weaker credit measures related to the acquisition of the three regulated gas distribution companies and a level of uncertainty related to the remaining financing plan for the acquisition. This uncertainty is related to potential receipt of proceeds from discrete noncore asset sales, the issuance of hybrid capital, the use of the at-the-market program, the dividend reinvestment plan, and incremental debt that will be used to fund the purchase price. We forecast pro forma debt to EBITDA will be about 4.9x, which provides limited cushion with respect to our target for the rating.

We could lower our rating on Enbridge if the company is unable to successfully raise additional funds through asset sales or other means such that adjusted debt to EBITDA is at or above 5x for a prolonged period.

We could revise the outlook to stable if the company is able to raise a substantial portion of the remainder of the capital to fund the acquisition and reduce debt to EBITDA closer to 4.75x during the next 12-18 months.

Environmental factors are a moderately negative consideration in our credit rating analysis of Enbridge. Climate transition factors into our assessment of all midstream companies. However, we note Enbridge has clearly articulated a strategy to lever its extensive asset portfolio to incorporate projects that address lowering its carbon footprint and longer-term energy transition. An example of this is the development of a solar farm adjacent to the Enbridge Ingleside Energy Centre that will produce the necessary power for the facility. These kinds of projects are available across the asset portfolio and include carbon capture and underground storage, renewable natural gas, offshore wind, and hydrogen. Social factors are also a moderately negative consideration, reflecting the ongoing opposition and ongoing litigation with respect to the company's Line 5 crude oil pipeline.

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- Criteria | Corporates | Industrials: Key Credit Factors For The Midstream Energy Industry, Nov. 15, 2021
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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TAB 5

92. Consistent with the timing recommended for mandatory reviews of the continued reasonableness of formulaically updated ROEs, experts for several parties (including J. Coyne,[87] D. D'Ascendis,[88] Dr. Villadsen[89] and Dr. Cleary[90]) suggested that the reasonableness of deemed equity ratios also be reviewed at the same time (i.e., every three to five years). R. Bell, meanwhile, suggested that equity thickness be reviewed each year concurrently with the formulaic update to ROEs, while D. Madsen proposed several specific conditions for updating equity thickness ratios going forward.

93. The Commission acknowledges the importance of ensuring predictability of the approved level of the deemed equity ratios moving forward, particularly while utilizing a formulaic approach to determine ROE. Since the deemed equity ratio influences the financial structure of a utility and, therefore, the ROE calculation, the Commission agrees with those parties that advocated for a concurrent review of both elements.

94. The Commission does not consider an annual assessment of deemed equity ratios as proposed by R. Bell to be warranted or cost-justified. Similarly, the Commission does not find merit in imposing upon electric (and presumably, gas) utilities the many conditions D. Madsen[91] recommended be satisfied before new equity ratios can be approved.

95. Instead, the Commission will institute a mandatory review of deemed equity ratios every five years consistent – and contemporaneous – with the approach outlined in Section 5.4 that the Commission will employ for the periodic evaluation of the formulaic approach. As with the latter, the length, scope and complexity of the equity thickness review process will not be predetermined but, rather, will depend on circumstances prevailing at that time.

96. Additionally, the Commission recognizes the value of permitting mid-term reopeners, either at its own discretion or upon application of interested parties, if compelling circumstances suggest that the deemed equity ratio is no longer reasonable. When initiated by parties other than the Commission, such mid-term reopeners will be subject to a two-stage review process similar to that for reviews of the formulaic approach.

6 Notional ROE and other formula variables

6.1 Overview

97. The Commission must determine a fair return for the utilities under its jurisdiction as part of fixing just and reasonable rates. In Section 5 of this decision, the Commission determines that it will adopt a formulaic approach to setting the ROE starting in 2024. As also set out in that section, the formula requires a notional ROE as a starting point. This notional ROE is determined with the same rigour and process used to determine ROE in prior fully litigated proceedings, and considers a variety of approaches, models and directional indices. However, this ROE will not be reflected in customer rates; rather, its sole purpose is to serve as an input to the approved

[87] Exhibit 27084-X0315, PDF page 7.
[88] Exhibit 27084-X0390, PDF page 118.
[89] Exhibit 27084-X0469, PDF pages 32-33.
[90] Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 13, lines 17-19.
[91] Exhibit 27084-X0292, PDF page 65.

formula. The ROEs produced by the formula will be approved on a final basis effective January 1 of each test year.

98. This section is organized as follows. In Section 6.2, the Commission discusses the extent to which the market data for the comparator group of utilities can be used to inform the determination of cost-of-capital parameters for the Alberta utilities. Section 6.3 determines a risk-free rate as an input to the ERP models, such as the CAPM, and the formulaic approach adopted by the Commission in this decision. In Section 6.4, the Commission determines the notional ROE by analyzing results of various financial models that were presented by proceeding participants. Finally, in Section 6.5, the Commission determines the values for the first and second factors of the formulaic approach to account for changes in GoC bond yields and changes in utility bond yield spread.

6.2 Comparability of representative utilities

99. In past GCOC proceedings, the Commission has frequently expressed concern with the wide range of conflicting evidence and polarized opinions on how it should approach setting a fair return on capital for the utilities it regulates. Oftentimes there was prolonged debate on the degree to which various utility comparator groups that parties relied on to construct models to estimate the ROE were representative of the Alberta utilities. An example of this is the 2018 GCOC proceeding, where parties proposed at least 13 different proxy groups consisting of various subsets of North American utilities.[92]

100. In order to address these concerns the Commission implemented a process to establish a comparator group of representative utilities that are similar to the Alberta utilities, for the purpose of informing the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE (the comparator group process).[93] The outcome of the comparator group process was that the parties reached a consensus on screening criteria and a comparator group of representative utilities resulting from the application of the screening criteria.[94]

101. The weight to be assigned to the specific utilities within the comparator group was not determined in the comparator group process. Instead, the Commission acknowledged that the parties did not agree that all companies in the comparator group are truly comparable to the Alberta utilities, and confirmed that the comparability of and weight to be assigned to the specific companies in the comparator group remained an issue to be determined in the proceeding.[95] The Commission specifically noted that parties could present evidence that certain companies in the comparator group should not be given any weight at all.[96]

102. The Commission is not persuaded by the argument that certain of the representative utilities in the comparator group lack comparability due to the involvement of their parent corporations in generation, retail or other unregulated business sectors. Concerns of this nature

92 Exhibit 27084-X0038, paragraph 8.
93 Exhibit 27084-X0034, paragraph 8.
94 Exhibit 27084-X0268.01, PDF page 4.
95 Exhibit 27084-X0239.01, PDF page 1, paragraph 2; Exhibit 27084-X0255, PDF page 4, paragraph 12; Exhibit 27084-X0268.01, PDF page 4.
96 Exhibit 27084-X0255, PDF page 4, paragraph 12.

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

[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

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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:

P_0 represents the current stock price;

D_1 … D_∞ 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]

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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.

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:

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

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 6

Home (/) / About Us (/about-us.html) / Who We Are

Who We Are

Our purpose is sustaining energy and water for life.

Plentiful sources of clean water and sustainably produced energy are essential for a healthy and happy life. They are the foundation of strong communities and a sustainable future.

Bringing this clean water and energy to people in a sustainable fashion is a major responsibility. We know that the services we provide directly affect and are essential to our customers' quality of life and wellbeing. From homes to hospitals, elder-care facilities to elementary schools, our customers depend on our ability to continue to provide safe and reliable energy and water services.

Sustainability is a foundation of our growth strategy and a guiding principle in how we plan, evaluate, and conduct our business. By embedding sustainability in our strategic business decisions and prioritizing customer needs, we know that we can do well by doing good.

Strategic Pillars

Our business strategy is centered on three strategic pillars that define what we deliver:

Growth

Algonquin is a growth-focused company. We have grown through organic initiatives, strategic acquisitions and development of world-class renewables.

Operational Excellence

We strive to work to the best of our capabilities. Our vision of operational excellence is focused on safety, security, and reliability.

Sustainability

Leading the transition to a low-carbon economy through the pursuit of global decarbonization partnership opportunities with like-minded corporate citizens.

Who We Are (/about-us/who-we-are.html) ›

Guiding Principles

How we strive to conduct ourselves.

Customer Centric

Foster a positive internal and external customer experience at every stage of the customer journey to build customer loyalty and satisfaction. Always consider the outcomes our decisions will have on the customer.

Integrity

Always honest, we do the right thing and adhere to moral and ethical principles for self and team.

Entrepreneurial

Have an optimistic interpretation of adverse events and see problems as potential opportunities; highly resilient, resourceful, and solution-oriented even within highly uncertain, resource constrained environments.

Outcome Focused

Have passion to exceed ambitious goals and safely deliver high quality business results. Strive to delegate for outcomes rather than by task.

Team Work, Trust, Inclusion and Respect

Value diverse teams of people. Encourage and help each other through collaboration. Inspire the exchange of ideas to come up with creative ways of doing things. Extend trust and create a feeling of belonging, listen for understanding to different perspectives by being respectful and professional.

Owner Mindset

Demonstrate ownership, taking smart risks, while remaining aligned to organizational pillars. Encourage individuals to take responsibility to hold themselves and others accountable.

Continuous Learning

Inquisitive and open minded, actively seeks new and varied experiences, and ideas. Is passionate about continual learning for self and team.

Our Businesses

Liberty™ (https://libertyutilities.com/)

What We Do (/about-us/what-we-do.html)

Regulated Services

Through our Regulated Services Group, we provide rate-regulated water, electricity, and gas utility services to over one million customer connections, primarily in North America. This includes:

- Electricity distribution
- Water distribution
- Wastewater treatment
- Natural gas distribution

Renewable Energy

The Renewable Energy Group generates and sells electrical energy produced by its diverse portfolio of renewable power generation facilities primarily located across the United States and Canada. This includes:

- Hydroelectric
- Wind
- Solar
- Thermal
- Renewable Natural Gas

More About Us

Who We Are (/about-us/who-we-are.html)

What We Do (/about-us/what-we-do.html)

Our Strategy (/about-us/our-strategy.html)

Leadership (/about-us/leadership.html)

Our History (/about-us/our-history.html)

Sustaining energy and water for life.

in (https://www.linkedin.com/company/algonquin-power-&-utilities-corp)
(https://twitter.com/AQN_Utilities)
(https://www.instagram.com/aqn_algonquinpowerandutilitie

Algonquin Power & Utilities Corp.

About Us (/about-us.html) Investors (http://investors.algonquinpower.com/)

Sustainability (/sustainability.html)
Careers (/careers.html)
News & Media (/news-and-media.html)
Contact (/contact.html)

Our operating business

Liberty™
(https://libertyutilities.com)

Stay Informed

Sign up (https://investors.algonquinpower.com/other-information/email-notification/default.aspx) to receive our email updates.

Terms of Use (/terms-of-use.html) Privacy Policy (/privacy-policy.html) Accessibility (/accessibility.html) Sitemap (/sitemap.html)

TAB 7

Algonquin

Company Overview fact sheet

Prepared as at July 30, 2022

Algonquin Power & Utilities Corp. (Algonquin) is a growing renewable energy and utility company with over U.S. $17 billion of assets across North America and internationally. We acquire and operate green and clean energy assets including hydroelectric, wind, and solar power facilities, as well as sustainable utility distribution businesses (water, wastewater treatment, electricity, and natural gas) through our operating subsidiary, Liberty.

For more than 30 years, Algonquin has demonstrated an unwavering commitment to delivering clean energy and water solutions. Our rapid growth has led both our regulated utility services and renewable energy business groups into different geographies and commodities, but our purpose remains unchanged – *Sustaining Energy and Water for Life.*

Strategic pillars

Our purpose is centered on our three strategic pillars:

Growth

We've always been a leader in growth. We focus on sustainable, rapid growth through strategic acquisitions and the development of world-class renewables.

Operational Excellence

We believe in doing everything to the best of our capabilities. Our vision of operational excellence is focused on safety, security, and reliability.

Sustainability

We partner with like-minded commercial and industrial customers to decarbonize their operations and reduce cumulative GHG emissions.

1) Total Assets as of December 31, 2021.
2) Includes renewable generating capacity in both the Regulated Services Group and Renewable Energy Group as well as a proportionate amount of the renewable energy generating capacity of Atlantica Sustainable Infrastructure plc (based on AQN's ~43% ownership interest in Atlantica Sustainable Infrastructure plc).

Algonquin

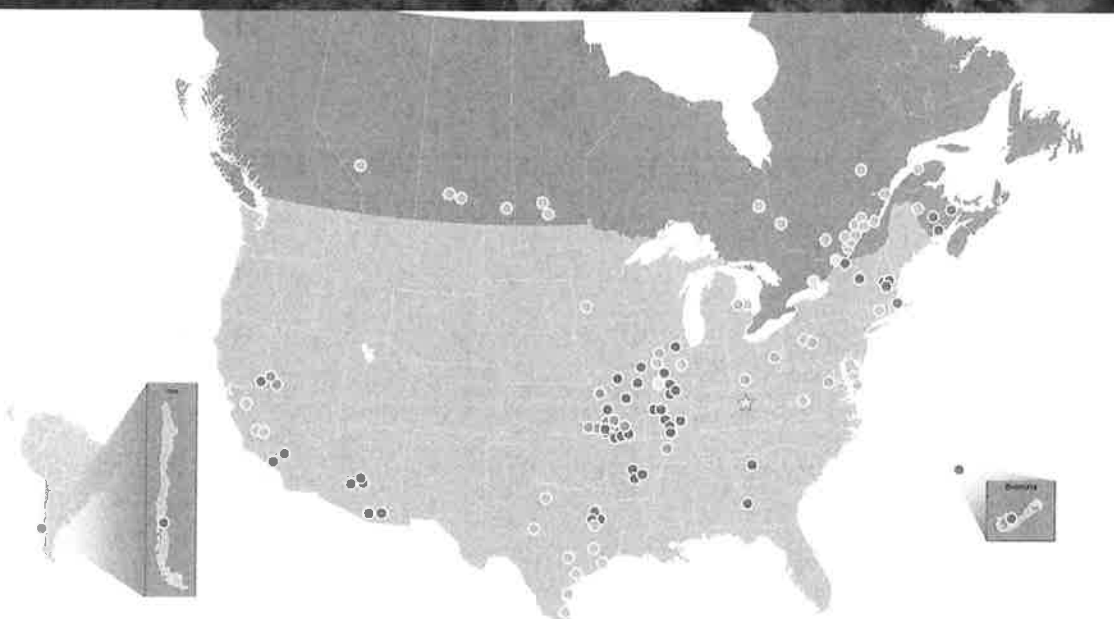
Company Overview fact sheet

Prepared as at July 20, 2022

Leading the transition to a low-carbon energy future

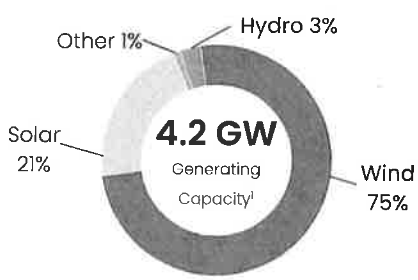
Sustainability is, and has always been, the foundation of our growth strategy and a guiding principle governing how we plan, evaluate, and conduct our business.

Learn more at **www.AlgonquinPowerandUtilities.com/Sustainability**



Renewable Energy Group

Our portfolio of long-term contracted wind, solar, and hydroelectric generating facilities represent ~4.2 GW of generating capacity[1] and prospective pipeline of over 3,800 MW of greenfield opportunities.



Regulated Services Group

Our diversified portfolio of rate-regulated electric, natural gas, water, and wastewater treatment utility systems and transmission operations serve the needs of over 1 million customer connections across North America.

Contact us

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1) Includes renewable generating capacity in both the Regulated Services Group and Renewable Energy Group as well as a proportionate amount of the renewable energy generating capacity of Atlantica Sustainable Infrastructure plc (based on AQN's ~43% ownership interest in Atlantica Sustainable Infrastructure plc)

2023 Annual Report

Algonquin Power & Utilities Corp.

Algonquin

Liberty

Overview and Business Strategy

AQN is incorporated under the *Canada Business Corporations Act*. AQN owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission assets. Through its activities, the Company aims to drive growth in earnings and cash flows to support a sustainable dividend and share price appreciation. AQN strives to achieve these results while also seeking to maintain a business risk profile consistent with its BBB flat investment grade credit ratings and a strong focus on Environmental, Social and Governance factors.

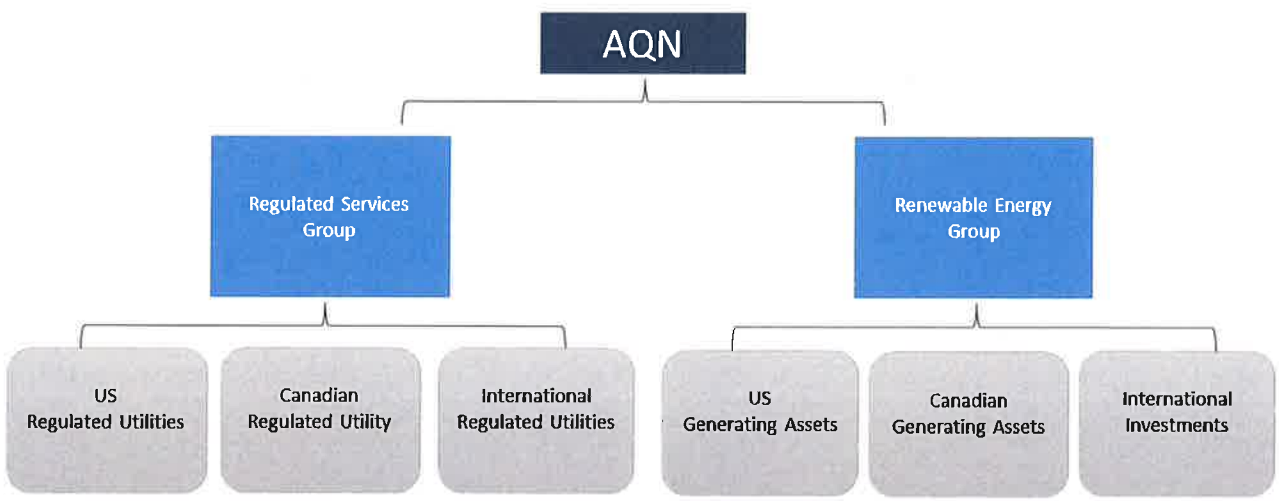
AQN's current quarterly dividend to shareholders is $0.1085 per common share, or $0.4340 per common share on an annualized basis. AQN believes that, on a long-term basis, its targeted annual dividend payout will allow for both a return on investment for shareholders and retention of cash within AQN to partially fund growth opportunities. Changes in the level of dividends paid by AQN are at the discretion of AQN's Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of AQN's financial performance and growth prospects.

AQN's operations are organized across two primary business units consisting of: the Regulated Services Group, which primarily owns and operates a portfolio of regulated electric, water distribution and wastewater collection and natural gas utility systems and transmission operations in the United States, Canada, Bermuda and Chile; and the Renewable Energy Group, which primarily owns and operates, or has investments in, a diversified portfolio of non-regulated renewable and thermal energy generation assets.

The Company is pursuing a sale of its renewable energy business. Due to the uncertainty regarding whether, when and on what terms such a sale may be consummated, the Company is not providing 2024 Adjusted Net Earnings per Common Share guidance (see *Caution Concerning Non-GAAP Measures*).

Summary Structure of the Business

The following chart depicts, in summary form, AQN's key businesses. A more detailed description of AQN's organizational structure can be found in the most recent AIF.



Regulated Services Group

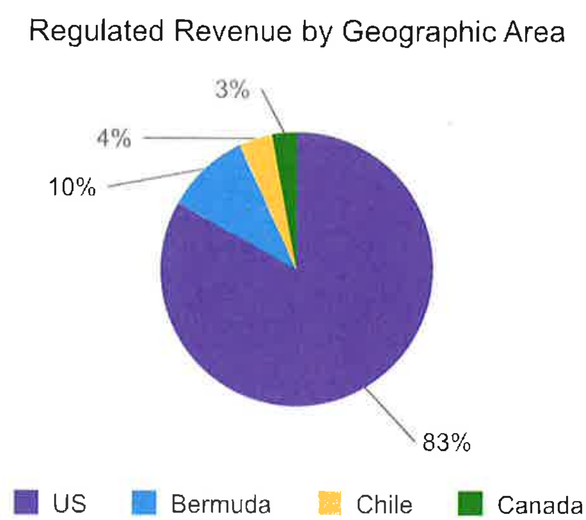
The Regulated Services Group primarily operates a diversified portfolio of regulated utility systems located in the United States, Canada, Bermuda and Chile serving approximately 1,256,000 customer connections as at December 31, 2023 (using an average of 2.5 customers per connection, this translates into approximately 3,140,000 customers). The Regulated Services Group seeks to provide safe, high quality, and reliable services to its customers and to deliver stable and predictable earnings to AQN. In addition to encouraging and supporting organic growth within its service territories, the Regulated Services Group may seek to deliver long-term growth through acquisitions of additional utility systems and pursuing "greening the fleet" opportunities.

The Regulated Services Group's regulated electrical distribution utility systems and related generation assets are located in the U.S. states of Arkansas, California, Kansas, Missouri, Nevada, New Hampshire and Oklahoma, as well as in Bermuda, which together served approximately 309,000 electric customer connections as at December 31, 2023. The group also owns and operates generating assets with a gross capacity of approximately 2.0 GW and has investments in generating assets with approximately 0.3 GW of net generation capacity.

The Regulated Services Group's regulated water distribution and wastewater collection utility systems are located in the U.S. States of Arizona, Arkansas, California, Illinois, Missouri, New York, and Texas as well as in Chile which together served approximately 572,000 customer connections as at December 31, 2023.

The Regulated Services Group's regulated natural gas distribution utility systems are located in the U.S. States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire, Missouri, and New York, and in the Canadian Province of New Brunswick, which together served approximately 375,000 natural gas customer connections as at December 31, 2023.

Below is a breakdown of the Regulated Services Group's Revenue by geographic area for the twelve months ended December 31, 2023.



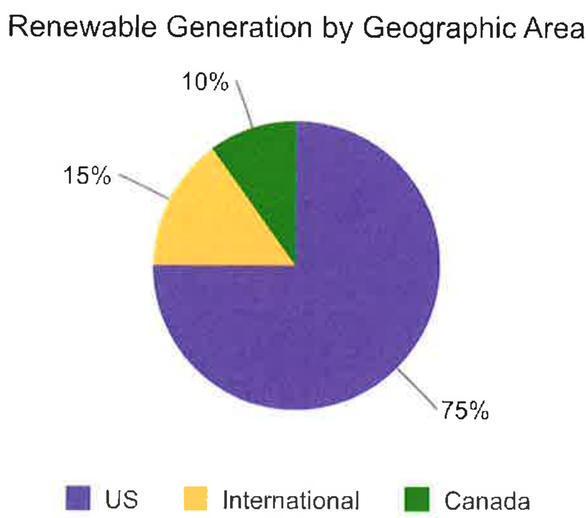
Renewable Energy Group

The Renewable Energy Group generates and sells electrical energy produced by its diverse portfolio of renewable power generation and clean power generation facilities located in the United States and Canada. The Renewable Energy Group seeks to deliver growth through new power generation projects and complementary projects, such as energy storage.

The Renewable Energy Group has economic interests in hydroelectric, wind, solar, renewable natural gas ("RNG") and thermal facilities which, as of December 31, 2023, had a combined net generating capacity attributable to the Renewable Energy Group of approximately 2.7 GW. Approximately 84% of the electrical output is sold pursuant to long-term contractual arrangements which as of December 31, 2023 had a production-weighted average remaining contract life of approximately 10 years.

In addition, the Renewable Energy Group has an approximately 42% indirect beneficial interest in Atlantica Sustainable Infrastructure plc ("Atlantica"). Atlantica owns and operates a portfolio of international clean energy and water infrastructure assets under long-term contracts with a Cash Available for Distribution weighted average remaining contract life of approximately 13 years as of December 31, 2023.

Below is a breakdown of the net generating capacity attributable to the Renewable Energy Group as of December 31, 2023, including the Company's approximately 42% interest in Atlantica.



2023 Fourth Quarter Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Three months ended December 31 2023		2022	
Revenue	$	**666.9**	$	748.0
Net earnings (loss) attributable to shareholders		**186.3**		(74.4)
Cash provided by operating activities		**200.7**		214.6
Adjusted Net Earnings[1]		**115.5**		97.6
Adjusted EBITDA[1]		**334.3**		295.5
Adjusted Funds from Operations[1]		**198.9**		191.9
Dividends declared to common shareholders		**75.6**		123.7
Weighted average number of common shares outstanding		**688,717,137**		683,281,170
Per share				
Basic net earnings (loss)	$	**0.27**	$	(0.11)
Diluted net earnings (loss)	$	**0.27**	$	(0.11)
Adjusted Net Earnings[1]	$	**0.16**	$	0.14
Dividends declared to common shareholders	$	**0.11**	$	0.18

[1] See *Caution Concerning Non-GAAP Measures.*

For the three months ended December 31, 2023, AQN reported basic net earnings per common share of $0.27 as compared to basic net loss per common share of $0.11 during the same period in 2022, an increase of $0.38.

The net earnings attributable to shareholders of $186.3 million for the three months ended December 31, 2023, was primarily driven by:

- Adjusted Net Earnings of $115.5 million, as further discussed below (see *Caution Concerning Non-GAAP Measures*); and
- a gain on investments carried at fair value (primarily the Company's investment in Atlantica) of $122.8 million; partially offset by
- an impairment of $23.5 million on development loans related to the simplification of the Company's development strategy; and
- other net losses of $13.9 million primarily due to costs associated with the Strategic Review and the pursuit of the sale of the Company's renewable energy business and write-off of deferred financing costs on the redemption of debt.

The net loss attributable to shareholders of $74.4 million for the three months ended December 31 2022, was primarily driven by:

- Adjusted Net Earnings of $97.6 million, as further discussed below (see *Caution Concerning Non-GAAP Measures)*;
- a gain on asset sales of $62.8 million in the Renewable Energy Group; and
- a gain on derivative financial instruments of $6.4 million; offset by
- non-cash losses on asset impairment charges of $159.6 million, mainly on the Senate Wind Facility (which began commercial operations in 2012) due to declining forecasted energy prices in ERCOT and an impairment of $75.9 million on the equity-method investment in the Texas Coastal Wind Facilities (as defined herein) primarily as a result of continued challenges with congestion at the facilities (collectively the "2022 Impairment").

For the three months ended December 31, 2023 AQN reported Adjusted Net Earnings per common share of $0.16 as compared to $0.14 per common share during the same period in 2022, an increase of $0.02 (*see Caution Concerning Non-GAAP Measures*). Adjusted Net Earnings increased by $17.9 million year over year (see *Caution Concerning Non-GAAP Measures*). This increase was primarily driven by:

- an increase of $23.9 million in the Regulated Services Group's operating profit primarily due to regulatory mechanisms and the implementation of new rates;
- an increase of $6.1 million in the Renewable Energy Group's operating profit primarily due to higher equity income from the Texas Coastal Wind Facilities; and
- an increase in tax recovery of $7.0 million primarily due to higher recognition of investment tax credits ("ITCs") and production tax credits ("PTCs") associated with renewable energy projects; partially offset by

- an increase of $7.3 million in depreciation expense driven by additional capital invested by the Company; and
- an increase of $9.9 million in interest expense, driven by higher interest rates as well as increased borrowings to support growth initiatives.

For the three months ended December 31, 2023, AQN experienced an average exchange rate of Canadian to U.S. dollars of approximately 0.7343 as compared to 0.7364 in the same period in 2022, and an average exchange rate of Chilean pesos to U.S. dollars of approximately 0.0011 for the three months ended December 31, 2023 as compared to 0.0011 for the same period in 2022. As such, any year over year variance in revenue or expenses, in local currency, at any of AQN's Canadian or Chilean entities is affected by a change in the average exchange rate upon conversion to AQN's reporting currency.

For the three months ended December 31, 2023, AQN reported total revenue of $666.9 million as compared to $748.0 million during the same period in 2022, a decrease of $81.1 million or 10.8%. The major factors impacting AQN's revenue in the three months ended December 31, 2023 as compared to the same period in 2022 are as follows:

(all dollar amounts in $ millions)		Three months ended December 31
Comparative Prior Period Revenue	**$**	**748.0**
REGULATED SERVICES GROUP		
Existing Facilities		
Electricity: Decrease is primarily due to lower wind pricing of approximately $12.0 million and unfavourable weather of approximately $6.0 million at the Empire (MO, KS, AR, OK) Electric System, with the remaining decrease primarily due to lower pass through commodity costs and other costs at the Granite State (NH) and Empire Electric Systems.		(38.6)
Natural Gas: Decrease is primarily due to lower pass through commodity costs.		(54.6)
Water: Increase is primarily due to the inflationary rate increase mechanism at the Suralis (Chile) Water System and organic growth at the Litchfield Park (AZ) Water and Sewer System and Gold Canyon (AZ) Sewer System.		5.4
Other: Decrease is primarily due to lower activity in the non-regulated business in Bermuda.		(4.0)
		(91.8)
Rate Reviews		
Electricity: Increase is primarily due to the implementation of new rates at the CalPeco (CA), Empire (OK), Granite State (NH) and Bermuda Electric Light Company ("BELCO") Electric Systems.		11.1
Natural Gas:		0.4
Water: Increase is primarily due to the implementation of new rates at the Park Water (CA) and Pine Bluff (AR) Water Systems.		5.2
		16.7
Foreign Exchange		**0.5**
RENEWABLE ENERGY GROUP		
Existing Facilities		
Hydro:		(0.2)
Wind CA: Decrease is primarily due to lower wind resources across all Canadian wind facilities.		(0.8)
Wind U.S.: Decrease is primarily due to lower wind resources across the majority of the U.S. wind facilities and lower availability revenue at the Maverick Creek Wind Facility.		(8.7)
Solar: Increase is primarily due to favourable capacity revenues across majority of the Solar facilities.		2.8
Thermal & Renewable Natural Gas: Decrease is primarily due to unfavourable overall energy market pricing for the Windsor Locks Thermal Facility partially offset by favourable capacity revenue for the Sanger Thermal Facility.		(0.6)
Other: Decrease is primarily due to lower portfolio optimization revenue.		(2.0)
		(9.5)
New Facilities		
Wind U.S: Increase is primarily driven by the Deerfield II Wind Facility (achieved COD in March 2023)		3.3
		3.3
Foreign Exchange		**(0.3)**
Current Period Revenue	**$**	**666.9**

2023 Annual Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Twelve months ended December 31 2023	2022	2021
Revenue	**$ 2,698.0**	$ 2,765.0	$ 2,274.1
Net earnings (loss) attributable to shareholders	**28.7**	(212.0)	264.9
Cash provided by operating activities	**628.0**	619.1	157.5
Adjusted Net Earnings[1]	**372.0**	420.3	449.0
Adjusted EBITDA[1]	**1,235.4**	1,192.8	1,076.3
Adjusted Funds from Operations[1]	**724.6**	790.3	757.9
Dividends declared to common shareholders	**301.8**	486.0	423.0
Weighted average number of common shares outstanding	**688,738,717**	677,862,207	622,347,677
Per share			
Basic net earnings (loss)	**$ 0.03**	$ (0.33)	$ 0.41
Diluted net earnings (loss)	**$ 0.03**	$ (0.33)	$ 0.41
Adjusted Net Earnings[1]	**$ 0.53**	$ 0.61	$ 0.71
Dividends declared to common shareholders	**$ 0.43**	$ 0.71	$ 0.67
Total assets	**18,374.0**	17,627.6	16,797.5
Long-term debt[2]	**8,516.3**	7,512.3	6,211.7

1 See *Caution Concerning Non-GAAP Measures.*

2 Includes current and long-term portion of debt and convertible debentures per the annual consolidated financial statements.

For the twelve months ended December 31, 2023, AQN reported basic net earnings per common share of $0.03 as compared to basic net loss per common share of $0.33 during the same period in 2022, an increase of $0.36.

The net earnings attributable to shareholders of $28.7 million for the twelve months ended December 31, 2023, was primarily driven by:

- Adjusted Net Earnings of $372.0 million, as further discussed below (see *Caution Concerning Non-GAAP Measures)*; partially offset by
- a loss on investments carried at fair value (primarily the Company's investment in Atlantica) of $230.0 million; and
- other net losses of $132.9 million, including the Securitization Write-Off (as defined herein) of $63.5 million, and impairment of assets and other losses of $46.5 million incurred as a result of the Kentucky Power Transaction Termination (the "Kentucky Power Impairment").

The net loss attributable to shareholders of $212.0 million for the twelve months ended December 31, 2022, was primarily driven by:

- Adjusted Net Earnings of $420.3 million, as further discussed below (see *Caution Concerning Non-GAAP Measures)*; and
- a gain on asset sales of $64.0 million in the Renewable Energy Group; offset by
- a loss on investments carried at fair value (primarily the Company's investment in Atlantica) of $499.1 million; and
- the 2022 Impairment of $235.5 million.

For the twelve months ended December 31, 2023, AQN reported Adjusted Net Earnings per common share of $0.53 compared to $0.61 per common share during the same period in 2022, a decrease of $0.08 (see *Caution Concerning Non-GAAP Measures*). Adjusted Net Earnings decreased by $48.3 million year over year (see *Caution Concerning Non-GAAP Measures*), primarily due to:

- a decrease of $26.4 million in the Renewable Energy Group's HLBV income as a result of the end of PTC eligibility on projects commissioned in 2012;
- a decrease of $12.5 million in the Renewable Energy Group's operating profit primarily as a result of a 5.3% decrease in wind production compared to the same period in 2022;

- an increase in earnings attributable to minority interest, exclusive of HLBV, of $34.6 million primarily due to the Company's sale in the fourth quarter of 2022 of a 49% ownership interest in the Odell, Deerfield and Sugar Creek Wind Facilities;
- an increase in interest expense of $75.1 million, driven by higher interest rates as well as increased borrowings to support growth initiatives;
- an increase in depreciation expense of $11.5 million, driven by additional capital invested by the Company; and
- an increase in administrative expenses of $10.2 million primarily due to technology costs, including costs associated with cyber security; partially offset by
- an increase of $90.5 million in the Regulated Services Group's operating profit primarily due to the implementation of new rates; and
- an increase in tax recovery of $39.2 million primarily due to higher recognition of ITCs and PTCs associated with renewable energy projects, and the tax impact of lower net earnings.

For the twelve months ended December 31, 2023, AQN experienced an average exchange rate of Canadian to U.S. dollars of approximately 0.7410 as compared to 0.7682 in the same period in 2022, and an average exchange rate of Chilean pesos to U.S. dollars of approximately 0.0012 for the twelve months ended December 31, 2023 as compared to 0.0011 for the same period in 2022. As such, any year-over-year variance in revenue or expenses, in local currency, at any of AQN's Canadian or Chilean entities is affected by a change in the average exchange rate upon conversion to AQN's reporting currency.

For the twelve months ended December 31, 2023, AQN reported total revenue of $2,698.0 million as compared to $2,765.0 million during the same period in 2022, a decrease of $67.0 million or 2.4%. The major factors resulting in the increase in AQN's revenue for the twelve months ended December 31, 2023 as compared to the same period in 2022 are as follows:

(all dollar amounts in $ millions)		Twelve months ended December 31
Comparative Prior Period Revenue	$	**2,765.0**
REGULATED SERVICES GROUP		
Existing Facilities		
Electricity: Decrease is primarily due to lower wind pricing of approximately $27.0 million and unfavourable weather of approximately $27.0 million at the Empire (MO, KS, AR, OK) Electric System with the remaining decrease primarily due to one-time insurance proceeds for the Neosho Ridge Wind Facility.		(66.7)
Natural Gas: Decrease is primarily due to lower pass through commodity costs.		(72.0)
Water: Increase is primarily due to the inflationary rate increase mechanism at the Suralis (Chile) Water System and organic growth at the Litchfield Park (AZ) Water and Sewer System and Gold Canyon (AZ) Sewer System.		21.3
Other: Decrease is primarily due to lower activity in the non-regulated business in Bermuda.		(5.6)
		(123.0)
Rate Reviews		
Electricity: Increase is primarily due to the implementation of new rates at the CalPeco (CA) Electric System retroactive to the first quarter of 2022, as well as the implementation of new rates at the Empire (OK, MO), Granite State (NH) and BELCO (Bermuda) Electric Systems.		84.6
Natural Gas: Increase is primarily due to the implementation of new rates at the EnergyNorth (NH), Peach State (GA), St. Lawrence (NY), Midstates (MO) and Empire (MO) Gas Systems.		5.2
Water: Increase is primarily due to the implementation of new rates at the Park (CA) Water System with one-time retroactive revenues to the third quarter of 2022 and the implementation of new rates at the Pine Bluff (AR) Water System.		12.4
		102.2
Foreign Exchange		**3.4**
RENEWABLE ENERGY GROUP		
Existing Facilities		
Hydro: Decrease is primarily driven by lower retail sales in the Maritimes Region and unfavourable energy market pricing for Western Canada Region.		(5.3)
Wind CA: Decrease is primarily due to lower wind resources across all Canadian wind facilities.		(7.6)
Wind U.S.: Decrease is primarily due to lower wind resources across the U.S. wind facilities.		(14.8)
Solar: Decrease is primarily driven by unfavourable energy market pricing across majority of the Solar facilities.		(2.1)
Thermal & Renewable Natural Gas: Decrease is primarily driven by unfavourable energy market pricing at the Sanger and Windsor Locks Thermal Facilities.		(17.3)
Other: Decrease is primarily due to lower portfolio optimization revenue.		(7.4)
		(54.5)
New Facilities		
Wind U.S: Increase is primarily driven by the Deerfield II Wind Facility (achieved COD in March 2023).		4.5
Other: Increase is primarily driven by the Blue Hill Wind Facility (achieved COD in April 2022).		4.4
		8.9
Foreign Exchange		**(4.0)**
Current Period Revenue	$	**2,698.0**

2023 Net Earnings Summary

Net earnings attributable to shareholders for the three months ended December 31, 2023 totaled $186.3 million as compared to net loss attributable to shareholders of $74.4 million during the same period in 2022, an increase of $260.7 million or 350.4%. Net earnings attributable to shareholders for the twelve months ended December 31, 2023 totaled $28.7 million as compared to net loss attributable to shareholders of $212.0 million during the same period in 2022, an increase of $240.7 million or 113.5%. The following table outlines the changes to net earnings (loss) attributable to shareholders for the three and twelve months ended December 31, 2023 as compared to the same periods in 2022. A more detailed analysis of these factors can be found under *AQN: Corporate and Other Expenses.*

Change in net earnings (loss) attributable to shareholders **(all dollar amounts in $ millions)**		**Three months ended December 31 2023**		**Twelve months ended December 31 2023**
Net loss attributable to shareholders – Prior Period Balance	**$**	**(74.4)**	**$**	**(212.0)**
Adjusted EBITDA[1]		38.8		42.6
Net earnings attributable to the non-controlling interest, exclusive of HLBV		(10.5)		(34.6)
Income tax recovery		(27.4)		24.8
Interest expense		(9.9)		(75.1)
Other net losses		(11.8)		(111.5)
Asset impairment charge		136.1		136.1
Impairment of equity-method investee		75.9		75.9
Unrealized loss on energy derivatives included in revenue		(2.6)		(6.6)
Pension and post-employment non-service costs		(0.2)		(8.9)
Change in value of investments carried at fair value		137.5		269.1
Tax equity issuance costs		—		(1.2)
Gain on derivative financial instruments		(5.8)		0.2
Gain on sale of assets		(62.8)		(64.0)
Foreign exchange		10.7		5.4
Depreciation and amortization		(7.3)		(11.5)
Net earnings attributable to shareholders – Current Period Balance	**$**	**186.3**	**$**	**28.7**
Change in Net Earnings ($)	**$**	**260.7**	**$**	**240.7**
Change in Net Earnings (%)		**350.4 %**		**113.5 %**

1 See *Caution Concerning Non-GAAP Measures.*

During the three months ended December 31, 2023, cash provided by operating activities totaled $200.7 million as compared to $214.6 million during the same period in 2022, a decrease of $13.9 million primarily as a result of changes in working capital items. During the three months ended December 31, 2023, Adjusted Funds from Operations totaled $198.9 million as compared to Adjusted Funds from Operations of $191.9 million during the same period in 2022, an increase of $7.0 million (see *Caution Concerning Non-GAAP Measures*).

During the three months ended December 31, 2023, Adjusted EBITDA totaled $334.3 million as compared to $295.5 million during the same period in 2022, an increase of $38.8 million or 13.1% (see *Caution Concerning Non-GAAP Measures*). A more detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below under *Non-GAAP Financial Measures.*

During the twelve months ended December 31, 2023, cash provided by operating activities totaled $628.0 million as compared to $619.1 million during the same period in 2022, an increase of $8.9 million primarily as a result of changes in working capital items. During the twelve months ended December 31, 2023, Adjusted Funds from Operations totaled $724.6 million as compared to Adjusted Funds from Operations of $790.3 million during the same period in 2022, a decrease of $65.7 million (see *Caution Concerning Non-GAAP Measures*).

During the twelve months ended December 31, 2023, Adjusted EBITDA totaled $1,235.4 million as compared to $1,192.8 million during the same period in 2022, an increase of $42.6 million or 3.6% (see *Caution Concerning Non-GAAP Measures*). A more detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below under *Non-GAAP Financial Measures*.

2023 Adjusted EBITDA Summary

Adjusted EBITDA (see *Caution Concerning Non-GAAP Measures*) for the three months ended December 31, 2023 totaled $334.3 million as compared to $295.5 million during the same period in 2022, an increase of $38.8 million or 13.1%. Adjusted EBITDA for the twelve months ended December 31, 2023 totaled $1,235.4 million as compared to $1,192.8 million during the same period in 2022, an increase of $42.6 million or 3.6%. The breakdown of Adjusted EBITDA by the Company's main business units and a summary of changes are shown below.

Adjusted EBITDA[1] by business units (all dollar amounts in $ millions)	**Three months ended December 31 2023**	**Three months ended December 31 2022**	**Twelve months ended December 31 2023**	**Twelve months ended December 31 2022**
Divisional Operating Profit for Regulated Services Group[1]	**$ 238.3**	$ 214.4	**$ 954.1**	$ 863.6
Divisional Operating Profit for Renewable Energy Group[1]	**107.6**	101.5	**371.8**	410.7
Administrative Expenses	**(19.3)**	(21.2)	**(90.4)**	(80.2)
Other Income & Expenses	**7.7**	0.8	**(0.1)**	(1.3)
Total AQN Adjusted EBITDA[1]	**$ 334.3**	$ 295.5	**$ 1,235.4**	$ 1,192.8
Change in Adjusted EBITDA[1] ($)	**$ 38.8**		**$ 42.6**	
Change in Adjusted EBITDA[1] (%)	**13.1 %**		**3.6 %**	

Change in Adjusted EBITDA[1] Breakdown (all dollar amounts in $ millions)	**Three months ended December 31, 2023 — Regulated Services**	**Renewable Energy**	**Corporate**	**Total**
Prior period balances	**$ 214.4**	**$ 101.5**	**$ (20.4)**	**$ 295.5**
Existing Facilities and Investments	12.1	5.4	6.9	24.4
New Facilities and Investments	—	(1.4)	—	(1.4)
Rate Reviews	11.7	—	—	11.7
Foreign Exchange Impact	0.1	2.1	—	2.2
Administrative Expenses	—	—	1.9	1.9
Total change during the period	**$ 23.9**	**$ 6.1**	**$ 8.8**	**$ 38.8**
Current period balances	**$ 238.3**	**$ 107.6**	**$ (11.6)**	**$ 334.3**

Change in Adjusted EBITDA[1] Breakdown (all dollar amounts in $ millions)	**Twelve months ended December 31, 2023 — Regulated Services**	**Renewable Energy**	**Corporate**	**Total**
Prior period balances	**$ 863.6**	**$ 410.7**	**$ (81.5)**	**$ 1,192.8**
Existing Facilities and Investments	26.7	(45.4)	1.2	(17.5)
New Facilities and Investments	—	9.1	—	9.1
Rate Reviews	62.6	—	—	62.6
Foreign Exchange Impact	1.2	(2.6)	—	(1.4)
Administrative Expenses	—	—	(10.2)	(10.2)
Total change during the period	**$ 90.5**	**$ (38.9)**	**$ (9.0)**	**$ 42.6**
Current period balances	**$ 954.1**	**$ 371.8**	**$ (90.5)**	**$ 1,235.4**

1 See *Caution Concerning Non-GAAP Measures.*

REGULATED SERVICES GROUP

The Regulated Services Group primarily operates rate-regulated utilities that as of December 31, 2023 provided distribution services to approximately 1,256,000 customer connections in the electric, natural gas, and water and wastewater sectors which is an increase of approximately 6,000 customer connections as compared to December 31, 2022.

The Regulated Services Group's strategy is to grow its business organically and through acquisitions. The Regulated Services Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing customer connections in the communities in which it operates.

Utility System Type

	As at December 31					
	2023			2022		
(all dollar amounts in $ millions)	Assets	Net Utility Sales[1]	Total Customer Connections[2]	Assets	Net Utility Sales[1]	Total Customer Connections[2]
Electricity	5,142.7	865.7	309,000	5,016.5	813.4	309,000
Natural Gas	1,843.5	354.1	375,000	1,722.6	345.9	375,000
Water and Wastewater	1,678.1	379.5	572,000	1,525.1	346.1	566,000
Other	281.3	51.1		290.7	54.2	
Total	$ 8,945.6	$ 1,650.4	1,256,000	$ 8,554.9	$ 1,559.6	1,250,000
Accumulated Deferred Income Taxes Liability	$ 750.8			$ 689.1		

[1] Net Utility Sales for the twelve months ended December 31, 2023 and 2022. See *Caution Concerning Non-GAAP Measures.*

[2] Total Customer Connections represents the sum of all active and vacant customer connections.

The Regulated Services Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and served approximately 309,000 customer connections in the U.S. States of California, New Hampshire, Missouri, Kansas, Oklahoma and Arkansas and in Bermuda as at December 31, 2023.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and served approximately 375,000 customer connections located in the U.S. States of New Hampshire, Illinois, Iowa, Missouri, Georgia, Massachusetts and New York and in the Canadian Province of New Brunswick as at December 31, 2023.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and served approximately 572,000 customer connections located in the U.S. States of Arkansas, Arizona, California, Illinois, Missouri, New York, and Texas and in Chile as at December 31, 2023.

2023 Annual Usage Results

Electric Distribution Systems

	Three months ended December 31		Twelve months ended December 31	
	2023	**2022**	**2023**	**2022**
Average Active Electric Customer Connections For The Period				
Residential	**262,900**	262,500	**262,700**	261,900
Commercial and industrial	**42,900**	43,200	**42,700**	42,800
Total Average Active Electric Customer Connections For The Period	**305,800**	305,700	**305,400**	304,700
Customer Usage (GW-hrs)				
Residential	**635.1**	653.3	**2,741.5**	2,899.6
Commercial and industrial	**902.2**	924.2	**3,820.0**	3,849.3
Total Customer Usage (GW-hrs)	**1,537.3**	1,577.5	**6,561.5**	6,748.9

For the three months ended December 31, 2023, the electric distribution systems' usage totaled 1,537.3 GW-hrs as compared to 1,577.5 GW-hrs for the same period in 2022, a decrease of 40.2 GW-hrs or 2.5%. The decrease in electricity consumption is primarily due to warmer weather at the Empire Electric System.

For the twelve months ended December 31, 2023, the electric distribution systems' usage totaled 6,561.5 GW-hrs as compared to 6,748.9 GW-hrs for the same period in 2022, a decrease of 187.4 GW-hrs or 2.8%. The decrease in electricity consumption is primarily due to a warmer winter and a cooler summer at the Empire Electric System.

Approximately 47% of the Regulated Services Group's electric distribution systems' revenues are not expected to be impacted by changes in customer usage, as they are subject to volumetric decoupling or represent fixed fee billings.

Natural Gas Distribution Systems

	Three months ended December 31		Twelve months ended December 31	
	2023	**2022**	**2023**	**2022**
Average Active Natural Gas Customer Connections For The Period				
Residential	**325,600**	321,100	**326,500**	320,300
Commercial and industrial	**40,800**	39,100	**40,600**	38,800
Total Average Active Natural Gas Customer Connections For The Period	**366,400**	360,200	**367,100**	359,100
Customer Usage (MMBTU)				
Residential	**4,358,000**	5,433,000	**18,822,000**	20,912,000
Commercial and industrial	**4,894,000**	5,723,000	**20,215,000**	20,607,000
Total Customer Usage (MMBTU)	**9,252,000**	11,156,000	**39,037,000**	41,519,000

For the three months ended December 31, 2023, usage at the natural gas distribution systems totaled 9,252,000 MMBTU as compared to 11,156,000 MMBTU during the same period in 2022, a decrease of 1,904,000 MMBTU, or 17.1%. The decrease in customer usage was primarily due to warmer weather at the Mid-States and Empire District Gas Systems.

For the twelve months ended December 31, 2023, usage at the natural gas distribution systems totaled 39,037,000 MMBTU as compared to 41,519,000 MMBTU during the same period in 2022, a decrease of 2,482,000 MMBTU, or 6.0%. The decrease in customer usage was primarily due to warmer weather at the Mid-States, New England Gas and Empire District Gas Systems.

Approximately 86% of the Regulated Services Group's gas distribution systems' revenues are not expected to be impacted by changes in customer usage, as they are subject to volumetric decoupling or represent fixed fee billings.

Water and Wastewater Distribution Systems

	Three months ended December 31		Twelve months ended December 31	
	2023	2022	2023	2022
Average Active Customer Connections For The Period				
Wastewater customer connections	**55,600**	49,100	**52,100**	48,100
Water distribution customer connections	**506,300**	504,600	**508,400**	501,300
Total Average Active Customer Connections For The Period	**561,900**	553,700	**560,500**	549,400
Gallons Provided (millions of gallons)				
Wastewater treated	**869**	822	**3,350**	3,233
Water provided	**10,188**	9,851	**41,435**	41,527
Total Gallons Provided (millions of gallons)	**11,057**	10,673	**44,785**	44,760

For the three months ended December 31, 2023, the water and wastewater distribution systems provided approximately 10,188 million gallons of water to customers and treated approximately 869 million gallons of wastewater. This is compared to 9,851 million gallons of water provided and 822 million gallons of wastewater treated during the same period in 2022, an increase in total gallons provided of 337 million or 3.4% and an increase in total gallons treated of 47 million or 5.7%. This increase in water provided is primarily due to customer growth at the Litchfield Park Water System and the increase in wastewater treated is primarily due to customer growth at the Litchfield Park and Rio Rico Water Systems.

For the twelve months ended December 31, 2023, the water and wastewater distribution systems provided approximately 41,435 million gallons of water to customers and treated approximately 3,350 million gallons of wastewater. This is compared to 41,527 million gallons of water provided and 3,233 million gallons of wastewater treated during the same period in 2022, a decrease in total gallons provided of 92 million or 0.2% and an increase in total gallons treated of 117 million or 3.6%. This decrease in water provided is mainly due to California drought restrictions at the Park Water System. The increase in wastewater treated is primarily due to customer growth at the Litchfield Park and Rio Rico Water Systems.

Approximately 50% of the Regulated Services Group's water and wastewater distribution systems' revenues are not expected to be impacted by changes in customer usage, as they are subject to volumetric decoupling or represent fixed fee billings.

2023 Regulated Services Group Operating Results

(all dollar amounts in $ millions)	Three months ended December 31 2023	Three months ended December 31 2022	Twelve months ended December 31 2023	Twelve months ended December 31 2022
Revenue				
Regulated electricity distribution	**$ 297.0**	$ 325.8	**$ 1,295.5**	$ 1,278.9
Less: Regulated electricity purchased	**(95.7)**	(124.2)	**(429.8)**	(465.5)
Net Utility Sales - electricity[1]	**201.3**	201.6	**865.7**	813.4
Regulated gas distribution	**167.4**	221.8	**621.2**	686.7
Less: Regulated gas purchased	**(71.6)**	(125.5)	**(267.1)**	(340.8)
Net Utility Sales - natural gas[1]	**95.8**	96.3	**354.1**	345.9
Regulated water reclamation and distribution	**100.5**	89.0	**399.1**	364.4
Less: Regulated water purchased	**(5.9)**	(8.6)	**(19.6)**	(18.3)
Net Utility Sales - water reclamation and distribution[1]	**94.6**	80.4	**379.5**	346.1
Other revenue[2]	**11.6**	14.5	**51.1**	54.2
Net Utility Sales[1,3]	**403.3**	392.8	**1,650.4**	1,559.6
Operating expenses	**(193.4)**	(185.8)	**(786.6)**	(736.5)
Income from long-term investments	**11.6**	5.2	**45.0**	21.9
HLBV[4]	**16.8**	2.2	**45.3**	18.6
Divisional Operating Profit[1,5]	**$ 238.3**	$ 214.4	**$ 954.1**	$ 863.6

1 See *Caution Concerning Non-GAAP Measures.*

2 See *Note 21* in the annual consolidated financial statements.

3 This table contains a reconciliation of Net Utility Sales to revenue. The relevant sections of the table are derived from and should be read in conjunction with the consolidated statement of operations and *Note 21* in the annual consolidated financial statements, "Segmented Information". This supplementary disclosure is intended to more fully explain disclosures related to Net Utility Sales and provides additional information related to the operating performance of the Regulated Services Group. Investors are cautioned that Net Utility Sales should not be construed as an alternative to revenue.

4 HLBV income represents the value of net tax attributes monetized by the Regulated Services Group in the period at the Luning and Turquoise Solar Facilities and the Neosho Ridge, Kings Point and North Fork Ridge Wind Facilities.

5 This table contains a reconciliation of Divisional Operating Profit to revenue for the Regulated Services Group. The relevant sections of the table are derived from and should be read in conjunction with the consolidated statement of operations and *Note 21* in the annual consolidated financial statements, "Segmented Information". This supplementary disclosure is intended to more fully explain disclosures related to Divisional Operating Profit and provides additional information related to the operating performance of the Regulated Services Group. Investors are cautioned that Divisional Operating Profit should not be construed as an alternative to revenue.

TAB 8

2023
Annual Report

Emera

Why Invest in Emera

With our proven strategy and portfolio of high-quality, regulated utilities, Emera is well positioned to continue delivering cleaner, more reliable energy for our customers while also providing our shareholders with long-term growth in earnings, cash flow and dividends.

VISIBLE GROWTH PLAN

$9B

capital investment plan[1] through 2026, with $5.4B+ committed to decarbonization and reliability

75%

of CapEx plan through 2026 is focused in Florida – the fastest-growing US state

7% to 8%

annualized, forecasted rate-base growth through 2026

STRONG RECORD OF DIVIDEND GROWTH

5.4%

annualized dividend growth since 2000

17 years

of consecutive dividend growth

5.7%

dividend yield[2]

EFFECTIVE AND COLLABORATIVE REGULATORY ENVIRONMENTS

Highly rated

regulatory environments

96%

of adjusted net income[3], excluding Corporate costs, derived from our regulated utilities

STRONG, SUSTAINABLE STRATEGY

47%

reduction in CO_2 emissions[4], and 77% reduction in coal use[5], since 2005

18%

of Board Director Nominees for 2024 identify as members of a diverse group, other than gender[6]

$12M

invested in our communities in 2023

0.25 Lost Time Injury Rate

down 11% from 2022 (0.28) and a 24% improvement over 5-year average (0.33)

1 Emera's capital investment plan includes $240 million equity investment in 2024.
2 Based on December 29, 2023, share price of $50.30.
3 Based on 2023 adjusted net income, excluding Corporate costs of $356 million and including holding company interest costs. Adjusted net income is a non-GAAP measure, which does not have a standardized meaning under USGAAP. For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2023 MD&A.
4 Undergoing final review and verification
5 As a percentage of total GWh generated compared to 2005 levels. Just 13 per cent of energy generated across Emera comes from coal.
6 One Director Nominee identifies as a racialized person and one Director Nominee identifies as a member of the LGBTQ2SI+ community.

Emera at a Glance

Data is as of December 31, 2023, unless otherwise indicated.

From our origins as a single electric utility, Emera has grown into an energy leader serving customers in Canada, the US and the Caribbean. Our companies include electric and natural gas utilities, gas pipelines, and energy marketing and trading operations.

HIGHLIGHTS

$39B
total assets

$7.6B
revenue

7,300
employees

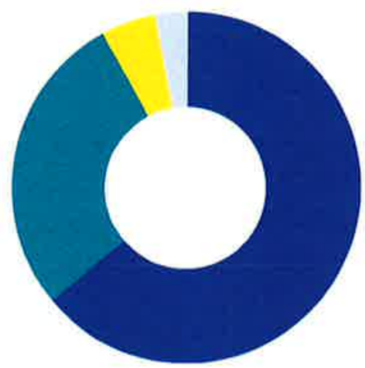
2.5M
customers

6
electric and natural gas utilities

ADJUSTED NET INCOME[1]

Excluding Corporate costs

BY GEOGRAPHY



- **64%** Florida
- **28%** Canada
- **5%** New Mexico
- **3%** Caribbean

1 Based on 2023 adjusted net income, excluding Corporate costs of $356 million and including holding company interest costs. Adjusted net income is a non-GAAP measure, which does not have a standardized meaning under USGAAP. For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2023 MD&A.

Management's Discussion & Analysis

As at February 26, 2024

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its consolidated subsidiaries and investments (collectively referred to as "Emera" or the "Company") during the fourth quarter of, and for the full year of, 2023 relative to the same periods in 2022 and selected financial information for 2021; and its financial position as at December 31, 2023 relative to December 31, 2022. The Company's activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

This MD&A should be read in conjunction with the Emera annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2023. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). Additional information related to Emera, including the Company's Annual Information Form can be found on Sedar+ at www.sedarplus.ca.

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At December 31, 2023, Emera's rate-regulated subsidiaries and investments include:

Emera Rate-Regulated Subsidiary or Equity Investment	Accounting Policies Approved/Examined By
Subsidiary	
Tampa Electric Company ("TEC") (1)	Florida Public Service Commission ("FPSC") and the Federal Energy Regulatory Commission ("FERC")
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board ("UARB")
Peoples Gas System, Inc. ("PGS") (1)	FPSC
New Mexico Gas Company, Inc. ("NMGC")	New Mexico Public Regulation Commission ("NMPRC")
SeaCoast Gas Transmission, LLC ("SeaCoast")	FPSC
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	Canadian Energy Regulator ("CER")
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados ("FTC")
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Equity Investments	
NSP Maritime Link Inc. ("NSPML")	UARB
Labrador Island Link Limited Partnership ("LIL")	Newfoundland and Labrador Board of Commissioners of Public Utilities
Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC ("M&NP")	CER and FERC
St. Lucia Electricity Services Limited ("Lucelec")	National Utility Regulatory Commission

(1) Effective January 1, 2023, Peoples Gas System ceased to be a division of TEC and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System, Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.

All amounts are in Canadian dollars ("CAD"), except for the Florida Electric Utility, Gas Utilities and Infrastructure, and Other Electric Utilities sections of the MD&A, which are reported in United States dollars ("USD") unless otherwise stated.

Effect of Foreign Currency Translation

Emera operates in Canada, the United States and various Caribbean countries and, as such, generates revenues and incurs expenses denominated in local currencies which are translated into CAD for financial reporting. Changes in translation rates, particularly in the value of the USD against the CAD, can positively or adversely affect results.

Results of foreign operations are translated at the weighted average rate of exchange, and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/USD exchange rates for 2023 and 2022 are as follows:

	Three months ended December 31 2023	Three months ended December 31 2022	Year ended December 31 2023	Year ended December 31 2022
Weighted average CAD/USD	**$ 1.36**	$ 1.37	**$ 1.35**	$ 1.34
Period end CAD/USD exchange rate	**$ 1.32**	$ 1.35	**$ 1.32**	$ 1.35

The table below includes Emera's significant segments whose contributions to adjusted net income are recorded in USD currency:

For the millions of USD	Three months ended December 31 2023	Three months ended December 31 2022	Year ended December 31 2023	Year ended December 31 2022
Florida Electric Utility	**$ 85**	$ 91	**$ 466**	$ 458
Gas Utilities and Infrastructure (1)	**41**	45	**142**	143
Other Electric Utilities	**3**	7	**26**	23
Other segment (2)	**(18)**	30	**(95)**	(50)
Total (3)	**$ 111**	$ 173	**$ 539**	$ 574

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.'s USD denominated debt.
(3) Excludes $73 million USD in MTM gain, after-tax, for the three months ended December 31, 2023 (2022 - $222 million USD MTM gain, after-tax) and MTM gain, after-tax of $116 million USD for the year ended December 31, 2023 (2022 - $130 million USD MTM gain, after-tax) and the GBPC impairment charge of nil for the three months and year ended December 31, 2023 (2022 - $54 million USD).

The translation impact of the change in FX rates on foreign denominated earnings increased net income by $13 million in Q4 2023 and $46 million for the year ended December 31, 2023, compared to the same periods in 2022. The translation impact of the change in FX rates on foreign denominated earnings decreased adjusted net income by $3 million in Q4 2023 and increased adjusted net income by $20 million for the year ended December 31, 2023 compared to the same periods in 2022. Impacts of the changes in the translation of the CAD include the impacts of Corporate FX hedges used to mitigate translation risk of USD earnings in the Other segment.

Business Overview and Outlook

Emera's 2023 results were impacted by macroeconomic conditions, specifically higher interest rates as well as other impacts of inflation. These macroeconomic conditions are likely to continue for the near term. For information on general economic risk, including interest rate and inflation risk, refer to the "Enterprise Risk and Risk Management - General Economic Risk" section.

FLORIDA ELECTRIC UTILITY

Florida Electric Utility consists of TEC, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. TEC has $12 billion USD of assets and approximately 840,000 customers at December 31, 2023. TEC owns 6,433 megawatts ("MW") of generating capacity, of which 74 per cent is natural gas fired, 19 per cent is solar and 7 per cent is coal. TEC owns 2,192 kilometres of transmission facilities and 20,299 kilometres of distribution facilities. TEC meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

TEC's approved regulated ROE range is 9.25 per cent to 11.25 per cent, based on an allowed equity capital structure of 54 per cent. An ROE of 10.20 per cent is used for the calculation of the return on investments for clauses.

TEC anticipates earning towards the lower end of the ROE range in 2024 but expects earnings to be higher than 2023. Normalizing 2023 for weather, TEC sales volumes in 2024 are projected to be higher than 2023 due to customer growth. TEC expects customer growth rates in 2024 to be comparable to 2023, reflective of the expected economic growth in Florida.

On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 million USD for 2026 and 2027, respectively. TEC's proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024 with a decision expected by the end of 2024.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC's ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the FPSC approved TEC's petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC and issuance of an order by the FPSC is expected by Q3 2024.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings. TEC will determine the timing of the request for recovery of Hurricane Idalia costs at a future time.

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

In 2024, capital investment in the Florida Electric Utility segment is expected to be $1.3 billion USD (2023 - $1.3 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include solar investments, grid modernization, storm hardening investments and building resilience.

CANADIAN ELECTRIC UTILITIES

Canadian Electric Utilities includes NSPI and ENL. NSPI is a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia. ENL is a holding company with equity investments in NSPML and LIL: two transmission investments related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador.

NSPI

With $7.2 billion of assets and approximately 549,000 customers, NSPI owns 2,422 MW of generating capacity, of which 44 per cent is coal and/or oil-fired; 28 per cent is natural gas and/or oil; 19 per cent is hydro, wind, or solar; 7 per cent is petroleum coke ("petcoke") and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPPs") and community feed-in tariff ("COMFIT") participants, which own 532 MW of capacity. NSPI also has rights to 153 MW of Maritime Link capacity, representing Nalcor Energy's ("Nalcor") Nova Scotia Block ("NS Block") delivery obligations, as discussed below. NSPI owns approximately 5,000 kilometres of transmission facilities and 28,000 kilometres of distribution facilities.

Nalcor is obligated to provide NSPI with approximately 900 Gigawatt hours ("GWh") of energy annually over 35 years. In addition, for the first five years of the NS Block, Nalcor is obligated to provide approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. The Energy Access Agreement enables NSPI to access a market-priced bid from Nalcor for up to 1.8 Terawatt hours ("TWh") of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

NSPI's approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent of approved rate base.

NSPI expects earnings and sales volumes to be higher in 2024 than 2023 but anticipates earning below its allowed ROE range in 2024.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding Fuel Adjustment Mechanism ("FAM") balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024. A decision is expected in the first half of 2024. It is anticipated that NSPI will apply to the UARB later in 2024 to collect additional under-recovered fuel amounts in 2025 or future periods, subject to the approval of the UARB.

On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023, the $24 million is deferred to "Other long-term assets", pending UARB approval. A decision is expected from the UARB in 2024.

On September 16, 2023, Nova Scotia was struck by post-tropical storm Lee and as a result, approximately 280,000 customers lost power. The total cost of storm restoration was $19 million, with $9 million charged to "OM&G", $5 million capitalized to property, plant and equipment ("PP&E) and $5 million deferred to the UARB approved storm rider. The storm rider, for each of 2023, 2024, and 2025, allows NSPI to apply to the UARB for deferral and recovery of expenses if major storm restoration expenses exceed approximately $10 million in any given year. The application for deferral of the storm rider is made in the year following the year of the incurred costs, with recovery beginning in the year after the application.

On February 2, 2023, the UARB approved the General Rate Application settlement agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and a further average increase of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB's established FAM process. It also established a storm rider, described above, and a demand-side management rider. On March 27, 2023, the UARB issued a final order approving the electricity rates effective on February 2, 2023.

In 2024, capital investment, including AFUDC, is expected to be $435 million (2023 - $451 million). NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

LIL

ENL is a limited partner with Nalcor in LIL. Construction of the LIL is complete and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

Upon issuance of the Commissioning Certificate, AFUDC equity earnings ceased and cash equity earnings and return of equity to Emera commenced. The first distribution was received from the LIL partnership in Q4 2023.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera's current equity investment is $747 million, comprised of $410 million in equity contribution and $337 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million once the final costing has been confirmed by Nalcor to determine the amount of the remaining investment.

GAS UTILITIES AND INFRASTRUCTURE

Gas Utilities and Infrastructure includes PGS, NMGC, SeaCoast, Brunswick Pipeline and Emera's equity investment in M&NP. PGS is a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida. NMGC is an intrastate regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico. SeaCoast is a regulated intrastate natural gas transmission company offering services in Florida. Brunswick Pipeline is a regulated 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick, to markets in the northeastern United States.

Peoples Gas System

With $2.8 billion USD of assets and approximately 490,000 customers, the PGS system includes 24,300 kilometres of natural gas mains and 13,500 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2 billion therms in 2023.

Beginning in 2024, the approved ROE range for PGS is 9.15 per cent to 11.15 per cent (2023 - 8.9 per cent to 11.0 per cent), based on an allowed equity capital structure of 54.7 per cent (2023 - 54.7 per cent). An ROE of 10.15 per cent (2023 - 9.9 per cent) is used for the calculation of return on investments for clauses.

New Mexico Gas Company, Inc.

With $1.8 billion USD of assets and approximately 540,000 customers, NMGC's system includes approximately 2,408 kilometres of transmission pipelines and 17,657 kilometres of distribution pipelines. Annual natural gas throughput was approximately 1 billion therms in 2023.

The approved ROE for NMGC is 9.375 per cent, on an allowed equity capital structure of 52 per cent.

Gas Utilities and Infrastructure Outlook

Gas Utilities and Infrastructure USD earnings are anticipated to be higher in 2024 than 2023, primarily due to a base rate increase effective January 2024 at PGS and an expected base rate increase effective Q4 2024 at NMGC, partially offset by lower asset optimization revenues expected at NMGC.

PGS expects rate base to be higher than in 2023 and anticipates earning within its allowed ROE range in 2024. USD earnings for 2024 are expected to be to be significantly higher than in 2023 primarily due to higher revenue from new base rates in support of significant ongoing system investment and continued customer growth in 2024, which is expected to be consistent with Florida's population growth rates.

On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

The 2020 PGS rate case settlement provided the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

NMGC expects 2024 rate base growth to be consistent with 2023, with slightly lower USD earnings as a result of lower asset optimization revenues, partially offset by higher revenue from expected new base rates, effective Q4 2024. NMGC anticipates earning near its authorized ROE in 2024. Customer growth rates are expected to be consistent with historical trends.

On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective Q4 2024. NMGC requested a $49 million USD increase in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent. A final order from the NMPRC is expected in Q3 2024.

In 2024, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $465 million USD (2023 – $495 million USD), including AFUDC. PGS and NMGC will make investments to maintain the reliability of their systems and support customer growth.

OTHER ELECTRIC UTILITIES

Other Electric Utilities includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities. ECI's regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island, and an equity investment in Lucelec on the island of St. Lucia.

BLPC

With $517 million USD of assets and approximately 134,000 customers, BLPC owns 243 MW of generating capacity, of which 96 per cent is oil-fired and four per cent is solar. BLPC owns approximately 188 kilometres of transmission facilities and 3,839 kilometres of distribution facilities. BLPC's approved regulated return on rate base for 2023 was 10 per cent.

GBPC

With $334 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 90 kilometres of transmission facilities and 994 kilometres of distribution facilities. GBPC's approved regulatory return on rate base for 2024 is 8.52 per cent (2023 – 8.32 per cent).

Other Electric Utilities Outlook

Other Electric Utilities' USD earnings in 2024 are expected to increase over the prior year.

BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the "Motion") and applied for a stay of the FTC's decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

TAB 9

FORTIS INC.

St. John's, NL - February 9, 2024

FORTIS INC. REPORTS FOURTH QUARTER & ANNUAL 2023 RESULTS

This news release constitutes a "Designated News Release" incorporated by reference in the prospectus supplement dated September 19, 2023 to Fortis' short form base shelf prospectus dated November 21, 2022.

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE: FTS), a well-diversified leader in the North American regulated electric and gas utility industry, released its 2023 fourth quarter and annual financial results[1].

Highlights

- Reported annual net earnings of $1.5 billion, or $3.10 per common share for 2023
- Annual adjusted net earnings per common share[2] of $3.09, up from $2.78 for 2022
- Capital expenditures[2] of $4.3 billion, yielding ~6% annual rate base growth[3]
- Sale of Aitken Creek closed in November 2023; proceeds further strengthened the balance sheet
- Achieved 50 years of common share dividend increases
- Scope 1 emissions 33% below 2019 levels; emissions reduction targets on track in support of 2050 net-zero goal

"We delivered another year of strong financial results reflecting the execution of our regulated growth strategy," said David Hutchens, President and Chief Executive Officer, Fortis Inc. "Rate base growth and the conclusion of key regulatory proceedings supported year over year earnings growth. We invested $4.3 billion of capital to enhance reliability, modernize the grid and deliver cleaner energy for customers while further reducing our carbon footprint."

"Last year Fortis was proud to celebrate 50 consecutive years of increases in dividends paid to shareholders," said Mr. Hutchens. "We remain focused on extending this track record as we execute our $25 billion five-year capital plan in support of our annual dividend growth guidance of 4-6% through 2028."

Sale of Aitken Creek

On November 1, 2023, the sale of Aitken Creek closed for approximately $470 million including working capital and closing adjustments. The transaction reflected a March 31, 2023 effective date. Net proceeds from the transaction further strengthened the balance sheet and provided additional funding flexibility in support of our regulated utility growth strategy.

In accordance with U.S. GAAP, reported net earnings attributable to common equity shareholders ("Net Earnings") includes the results for Aitken Creek until the November 1, 2023 date of disposition. Adjusted net earnings attributable to common equity shareholders[2] ("Adjusted Net Earnings") reflects results for Aitken Creek through the March 31, 2023 effective date.

Net Earnings

The Corporation reported Net Earnings of $1.5 billion, or $3.10 per common share for 2023, compared to $1.3 billion, or $2.78 per common share for 2022. Growth in earnings was primarily driven by rate base growth across our utilities and the new cost of capital parameters approved for FortisBC effective January 1, 2023. Higher earnings in Arizona also contributed to earnings growth, reflecting higher retail electricity sales, new customer rates at Tucson Electric Power ("TEP") effective September 1, 2023, and lower depreciation expense associated with the retirement of the San Juan generating station in 2022. An increase in the market value of certain investments that support retirement benefits, and the higher U.S.-to-Canadian dollar exchange rate, also favourably impacted earnings year over year. The increase was partially offset by higher corporate finance costs and lower earnings associated with Aitken Creek. In addition, net earnings per common share reflected an increase in the weighted average number of common shares outstanding largely associated with the Corporation's dividend reinvestment plan.

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[1] Financial information is presented in Canadian dollars unless otherwise specified.
[2] Non-U.S. GAAP Measures - Fortis uses financial measures that do not have a standardized meaning under generally accepted accounting principles in the United States of America ("U.S. GAAP") and may not be comparable to similar measures presented by other entities. Fortis presents these non-U.S. GAAP measures because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects. Refer to the Non-U.S. GAAP Reconciliation provided herein.
[3] Calculated using a constant U.S. dollar-to-Canadian dollar exchange rate.

Management Discussion and Analysis

Contents

Dated February 8, 2024

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2023 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 42. Further information about Fortis, including its Annual Information Form filed on SEDAR+, can be accessed at www.fortisinc.com, www.sedarplus.ca, or www.sec.gov.

Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.35 and 1.30 for the years ended December 31, 2023 and 2022, respectively; (ii) 1.32 and 1.36 as at December 31, 2023 and 2022, respectively; (iii) average of 1.36 for the quarters ended December 31, 2023 and 2022; and (iv) 1.30 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 44.

ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $12 billion in 2023 and total assets of $66 billion as at December 31, 2023.

Regulated utilities account for 99% of the Corporation's assets. The Corporation's 9,600 employees serve 3.5 million utility customers in five Canadian provinces, ten U.S. states and three Caribbean countries. As at December 31, 2023, 64% of the Corporation's assets were located in the U.S., 33% in Canada and the remaining 3% in the Caribbean. Operations in the U.S. accounted for 56% of the Corporation's 2023 revenue, with the remaining 39% in Canada, and 5% in the Caribbean.

Fortis is principally an energy delivery company, with 93% of its assets related to transmission and distribution. The business is characterized by low-risk, stable and predictable earnings and cash flows. Earnings, EPS and TSR are the primary measures of financial performance.

Fortis' regulated utility businesses are: ITC (electric transmission - Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas, Oklahoma and Wisconsin); UNS Energy (integrated electric and natural gas distribution - Arizona); Central Hudson (electric transmission and distribution, and natural gas distribution - New York State); FortisBC Energy (natural gas transmission and distribution - British Columbia); FortisAlberta (electric distribution - Alberta); FortisBC Electric (integrated electric - British Columbia); Newfoundland Power (integrated electric - Newfoundland and Labrador); Maritime Electric (integrated electric - Prince Edward Island); FortisOntario (integrated electric - Ontario); Caribbean Utilities (integrated electric - Grand Cayman); and FortisTCI (integrated electric - Turks and Caicos Islands). Fortis also holds equity investments in the Wataynikaneyap Partnership (electric transmission - Ontario) and Belize Electricity (integrated electric - Belize).

The Corporation's non-regulated business is limited to Fortis Belize (three hydroelectric generation facilities - Belize). The Aitken Creek natural gas storage facility in British Columbia was sold on November 1, 2023 with a March 31, 2023 effective date (see "Key Developments" below). With the disposition of Aitken Creek, the Corporation's non-regulated business is now reported in the Corporate and Other segment.

Fortis has a unique operating model with a small corporate office in St. John's, Newfoundland and Labrador and business units that operate on a substantially autonomous basis. Each utility has its own management team and board of directors, with most having a majority of independent board members, which provides effective oversight within the broad parameters of Fortis policies and best practices. Subsidiary autonomy supports constructive relationships with regulators, policy makers, customers and communities. Fortis believes this model enhances accountability, opportunity and performance across the Corporation's businesses, and positions Fortis well for future investment opportunities.

Fortis is focused on providing safe, reliable and cost-effective energy service to customers. Delivering a cleaner energy future is the Corporation's core purpose. In addition, management is focused on delivering long-term profitable growth for shareholders through the execution of its Capital Plan and the pursuit of investment opportunities within and proximate to its service territories.

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2023 Annual Financial Statements.

KEY DEVELOPMENTS

Regulatory Updates

See "Regulatory Highlights - Significant Regulatory Matters" on page 14.

Sale of Aitken Creek

On November 1, 2023, FortisBC Holdings Inc. completed the sale of its Aitken Creek business to a subsidiary of Enbridge Inc. for approximately $470 million including working capital and closing adjustments, following the satisfaction of all regulatory requirements. The transaction reflected a March 31, 2023 effective date. Net proceeds from the transaction further strengthened the Corporation's balance sheet and provided additional funding flexibility in support of our regulated utility growth strategy.

In accordance with U.S. GAAP, Common Equity Earnings includes the results for Aitken Creek until the November 1, 2023 date of disposition. Management has excluded Aitken Creek's earnings recognized from the March 31st effective date through to the November 1st disposition date, as well as the gain recorded on the sale, in arriving at Adjusted Common Equity Earnings and Adjusted Basic EPS (see "Non-U.S. GAAP Financial Measures" on page 13).

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	**2023**	2022	Variance
Common Equity Earnings			
Actual	**1,506**	1,330	176
Adjusted (1)	**1,502**	1,329	173
Basic EPS *($)*			
Actual	**3.10**	2.78	0.32
Adjusted (1)	**3.09**	2.78	0.31
Dividends			
Paid per common share *($)*	**2.29**	2.17	0.12
Actual Payout Ratio *(%)*	**73.7**	78.1	(4.4)
Adjusted Payout Ratio *(%)* (1)	**73.9**	78.1	(4.2)
Weighted average number of common shares outstanding *(# millions)*	**486.3**	478.6	7.7
Operating Cash Flow	**3,545**	3,074	471
Capital Expenditures (1)	**4,329**	4,034	295

(1) *See "Non-U.S. GAAP Financial Measures" on page 13*

TAB 10

demand – both residential and industrial. For example, since 2013 in Alberta, we've reduced O&M costs per kilometre of electric distribution line by 29 per cent and reduced natural gas distribution costs per customer by 39 per cent.

In Puerto Rico, LUMA Energy – our joint venture with Quanta Services – continues to identify and complete initiatives that are bringing increased reliability, renewable energy and upgrades to Puerto Rico's electric system. In 2023, the installation of automation equipment has created dramatic results in terms of minimizing service interruptions. LUMA continues to be financed by our FEMA contract, which funds our projects to improve the resiliency and reliability of the electric system for Puerto Rican citizens and businesses.

Across all our operating areas, we are committed to working with governments, regulators and partners to ensure our energy systems provide a strong sense of value to our customers and communities, with modernized technology that enables EVs, renewables, and energy storage along with the reliability that is so crucial to a strong economy.

In October 2023, ATCO Australia was selected with our partner BOC Linde to develop the FEED study for the South Australian Government's Hydrogen Jobs Plan. Our contract is for the delivery of a strategy and development program for the government's proposed 250-MW hydrogen production facility, along with a 200-MW hydrogen-fuelled electricity generating facility and related hydrogen storage. Our selection as the winning bidder speaks to the expertise of our people and the advancements we have made with the Clean Energy Innovation Hub in Australia.

ATCO EnPower, our North American clean fuels, power generation, renewables and storage division, made meaningful progress in advancing our world class clean hydrogen production facility in the Alberta Industrial Heartland, including solidifying land, water and hydrogen storage positions. This world scale project will be fully integrated with hydrogen storage, transportation, and carbon capture and sequestration.

We also marked almost a full year of operating the new renewables assets we acquired in January of 2023; the 232-MW Forty Mile and Adelaide wind assets have contributed strong revenues over the course of 2023, underpinned by a long-term power purchase agreement with Microsoft for 150-MW of the energy generated by Forty Mile Wind Phase 1 Project. We also continued to advance the development of the wind and solar projects that are part of a promising development pipeline.

Building equitable partnerships with Indigenous communities

For decades we have partnered with Indigenous communities to create truly equitable partnerships.

In 2023, we negotiated an agreement for the Chiniki and Goodstoney First Nations to take a majority equity position in our Deerfoot and Barlow solar developments, making them 51 per cent owners in the Calgary facilities. Not only does this partnership support energy transition and our overall strategy related to renewable generation and Indigenous engagement, it also creates meaningful and long-lasting economic returns for the Chiniki and Goodstoney communities.

Collaborating for the betterment of communities

Canadian Utilities is committed to meeting and supporting the needs of our communities.

In 2023 we established the Community Energy Fund to help Alberta organizations move towards a more sustainable, net zero future. In its inaugural year, the fund provided support for twelve Alberta schools, community groups and municipalities to help them achieve their energy and sustainability goals, with projects that include energy audits, community charging stations, solar panel installations and LED light conversions.

I am especially proud of two programs we have that help deliver unique experiences for young people. In Australia we are providing students with a look at the many exciting careers in the energy industry. As part of the Government of Western Australia's *Year 9 Career Taster Program* we welcomed 50 students to our Jandakot Operations Centre to spark their 'career curiosity' and make connections between education and post-school opportunities. In Alberta we expanded our Fire Cadet program to the community of Grande Prairie. More than 20 youth will develop important life skills, leadership and self-confidence, while gaining a better understanding of firefighting as a career.

Supporting the talent and diversity of the Canadian Utilities team

The challenges of our energy transition are formidable, but our dedicated team of employees across Canada, Australia, Puerto Rico, and Mexico continues to display courage and excellence in delivering essential services.

In 2023, those traits were on full display as our teams dealt with unprecedented wildfires in Alberta and the Northwest Territories. In concert with emergency services and communities, our people delivered a

OUR OPERATING ENVIRONMENT

We operate in a complex and ever-changing world, so striving to anticipate and understand the broad trends impacting our customers and communities is paramount. This appreciation and understanding of our operating environment allows us to better identify possible challenges while capitalizing on emerging opportunities and continuing to deliver high-performing results.

Key market trends

Global and societal changes can create opportunities or present challenges, and they play an important role in shaping the way we collaborate with our customers, team members, share owners and the communities in which we operate. The following is an examination of the key market trends we are seeing and how we are positioning our businesses to respond.

ENERGY TRANSITION & ENERGY SECURITY

The global energy transition is a complex ongoing process requiring long-term energy strategies, which utilize appropriate technologies and fuels to produce energy that satisfies evolving demand. The energy transition must balance reliability and resilience with affordability while achieving higher energy security and lower emissions toward a net-zero future. With this, the utilities industry is changing to focus on decarbonization, digitalization, decentralization, and evolving customer demand. The worldwide push towards reaching net-zero, evolving regulations to encourage the advancement of new technologies, emissions reduction targets, and government incentives present opportunities for utility companies. ATCO Energy Systems is well positioned to capitalize on these trends. We also believe that new technologies will create opportunities for efficiencies within our utilities businesses to drive down customers' costs.

Additionally, the political and societal push to address climate change is driving further investment into storage and grid balancing solutions to improve system reliability. However, this ongoing transition also brings policy uncertainty and risks, delaying investment decisions that would align with our 2050 net-zero targets.

Extreme weather events such as heat waves, wildfires, ice and frost events, and large storms are becoming more frequent and more intense through the impact of climate change. Canadian Utilities is uniquely positioned to provide support to communities and areas effected by these catastrophic events, while working diligently to minimize our impact with our net-zero by 2050 aspiration as well as our initial set of 2030 ESG Targets. We also maintain in-depth emergency response measures for these extreme weather events, including our robust Wildfire Management Plans. When planning for capital investment or acquiring assets, site specific climate and weather factors, such as flood plain mapping and reliability during extreme weather history are considered.

GLOBAL SECURITY AND DEFENSE

Over the last few years we have seen an increase in geopolitical tensions and conflicts. Such geopolitical events can cause varying levels of disruption, which can generate labour shortages in critical trades, persistent global supply chain delays that can affect project productivity and delivery, and directed cybersecurity threats and technology leaks. As part of its corporate strategy, ATCO is vigilant about the increased risks and threats that may impact us. Beyond the business impact, the human toll can be staggering, whether due to hostilities, food insecurity or loss of homes.

We unfortunately only see this global polarization and resulting tension increasing over the years to come. Governments and business will both need to bring all their resources to bear to protect our democracies and civilians. These global security risk further amplify the need for protection of the critical infrastructure in the areas we operate, and to provide support to those impacted by geopolitical events. Employees throughout Canadian Utilities are trained in using the Incident Command Systems (ICS) and have a broad range of skills and expertise that can support recovery of communities in need or damaged infrastructure.

INDIGENOUS RECONCILIATION

Share owners are increasingly favouring companies that align with their social values, including those that show a commitment towards Indigenous reconciliation. Additionally, principles from the United Nations Declaration on the Rights of Indigenous People Act (UNDRIP) are being incorporated into certain legislative acts, and companies that genuinely pursue equitable partnerships, provide employment opportunities, and have robust Indigenous procurement standards set themselves apart when bidding on government contracts or applying for government projects or grants.

The progress Canadian Utilities has made in creating equitable partnerships with Indigenous Communities is a hallmark of our approach to business. This is highlighted by ATCO Energy Systems' landmark electricity purchase agreements with remote communities that support reduction of diesel reliance, and ATCO EnPower's equity partnership with the Chiniki and Goodstoney First Nations for the Deerfoot and Barlow solar projects. We believe that creating equitable partnerships for Indigenous communities should be the standard for governments and businesses alike in support of reconciliation and inclusiveness.

We pride ourselves on being a leader in the communities we serve through our various initiatives with Indigenous groups, and local charities. ATCO, Canadian Utilities' parent company, has incorporated an Indigenous Advisory Board led by senior Indigenous directors from across Canada and they have been instrumental with the advice provided to our businesses.

CHANGING WORKFORCE

Canadian Utilities' businesses serve a broad range of people and communities which requires that we attract a broad range of backgrounds and dynamic experience in our workforce. Additionally, in the jurisdictions in which we operate there is a multigenerational workforce with a high number of employees between 55 and 64 years of age. There is a risk of labour shortages as many of our colleagues work towards retirement.

We strive to demonstrate our values to attract potential employees while providing the development, training and leadership for them to thrive. We have an ongoing commitment to inclusion practices, fostering a safe working environment, developing mentors, removing barriers, and providing development and succession planning. This is critical to creating an equitable playing field of opportunity and supporting the internal pipeline of talent on which our future relies. Canadian Utilities works to build a community where everyone can bring their whole selves to work and reach their full potential. This strategy holds us accountable, enhances a sense of belonging and drives superior business performance.

THE GLOBAL ECONOMY AND MARKET VOLATILITY

The global impacts of large-scale world events can create challenges for any business. The recent examples of the worldwide pandemic, increasingly destructive weather events, supply chain interruptions, and geopolitical tensions and wars show that a business needs to be ready for anything. By being a forward-looking company, Canadian Utilities can, and has, mitigated the impacts such changes bring.

We view total share owner return through a long-term lens, and our corporate actions are consistent with that. Many of our core financial pillars – minimum cash balance, strong focus on access to capital, and adequate leverage – reflect learnings from history. Whether it be capital recycling through asset sales, expanding through new acquisitions or purposeful capital allocation to our existing companies, proactive decisions made across our businesses have allowed us to deliver strong results through various geopolitical events and economic cycles.

PUBLIC DEBT, INFLATION AND INTEREST RATES

Recent years have seen inflation and interest rates increase globally and create challenges for investment and risk to managing operating costs. Additionally, the increased expenditures of governments around the world in response to the COVID-19 pandemic and the accumulated public debt will have lingering impacts on the global economy for years to come. Canadian Utilities has operated for over 100 years through other times of high interest rates and rising inflation and our record shows our ability to manage and thrive despite these conditions. We do not view these macroeconomic impacts as transitory, and are actively managing our portfolio with this in mind.

ATCO Energy Systems' utility businesses in Alberta, Australia, and Puerto Rico have regulatory mechanisms that take inflation into consideration, providing resiliency for a large portion of our earnings, and ATCO EnPower limits its exposure to the fluctuating commodities market by signing Power Purchase Agreements (PPA). The key to Canadian Utilities' success in weathering these conditions is our consistent approach to being proactive when it comes to planning and operations, allowing us to take advantage of opportune times for project purchasing, managing staffing requirements, and taking into account relevant exchange rates.

DIGITIZATION AND ARTIFICIAL INTELLIGENCE (AI)

Artificial Intelligence is a critical topic as companies navigate how and when to apply these fast emerging technologies. AI can range from the personal assistants in phones, generative AI incorporated into different software, to technology providing real-time information to a company. Additionally, many companies are already in the process of digitization to increase operational efficiencies, reliability of information, and managing large amounts of data.

Within ATCO Energy Systems, leveraging data and digitizing our utilities technology remains a key priority and one that will drive continued efficiencies as our system becomes more capable of predicting and responding to customer needs. As part of this process, the last few years have seen us complete a number of digitization and modernization objectives, including the deployment of Advanced Metering Infrastructure (AMI), the latest in metering technology; working towards deploying an Advanced Distribution Management System, a platform for a variety of smart grid functions; as well as implementation of a workforce and asset management program that provides an efficient way to track, manage, and dispatch work to field-based employees based on urgency.

AI has the potential to enhance the capabilities of our digital systems. While our AMI technology is already allowing for faster detection of outages, applied AI could predict infrastructure maintenance. Like all new technologies, proper governance and risk management need to be part of the plan, but the successful integration of AI and digital technologies could provide long-term operational and financial value to our businesses.

TAB 11

ENERGY INSTITUTE AT HAAS

Energy Institute WP 329R

Rate of Return Regulation Revisited

Karl Dunkle Werner and Stephen Jarvis

Revised April 2024

Rate of Return Regulation Revisited

Karl Dunkle Werner and Stephen Jarvis *

April 2024

Abstract

Utility companies recover their capital costs through regulator-approved rates of return. Using a comprehensive database of utility rate cases we estimate that utilities' regulated returns on equity are significantly higher than several benchmark measures would suggest. We show that regulated returns on equity respond more quickly to increases in underlying capital costs than they do to decreases. We then provide evidence that higher regulated returns on equity lead utilities to own more capital. A one percentage point rise in return on equity increases capital investment by 2–4%. Overall we find excess costs to US consumers averaging $6 billion per year.

JEL Codes: Q40, L51, L94, L95

Keywords: Utility, Rate of Return, Regulation, Electricity, Natural Gas, Capital Investment

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Jarvis: Department of Geography and Environment, London School of Economics, s.jarvis@lse.ac.uk. The views and findings presented this research do not necessarily represent the views of the US Treasury or any other author affiliation. The authors thank seminar participants at the Berkeley Electricity Markets group, the LSE Workshop in Environmental Economics, the POWER Conference and the AERE Summer Conference. The authors wish to acknowledge the advice of Severin Borenstein, Jim Sallee, and Meredith Fowlie. All errors are, of course, our own. Karl is grateful for the generous support of the Alfred P. Sloan Foundation Pre-doctoral Fellowship on Energy Economics, awarded through the NBER.

1 Introduction

In the two decades from 1997 to 2017, real annual capital spending on electricity transmission and distribution infrastructure by major utilities in the United States has more than doubled (EIA 2018a, 2018b). The combined total is now more than $90 billion per year (IEA 2023). This trend is expected to continue, both in the US and globally, with investment expected to double or even triple by the 2030s and 2040s (ibid).

These large capital investments are generally viewed as utility companies modernizing an aging grid and making the necessary upgrades to support the clean energy transition underway in much of the utility sector. However, it is noteworthy that over recent years, utilities have earned sizeable regulated rates of return on their capital assets, particularly when set against the unprecedented low interest rate environment from 2008–2022. When the economy-wide cost of capital fell, utilities' regulated rates of return did not fall nearly as much. This gap raises the prospect that at least some of the growth in capital spending could be driven by utilities earning excess regulated returns.

Utilities over-investing in capital assets as a result of excess regulated returns is an age-old concern in the sector (Averch and Johnson 1962). The resulting costs from "gold plating" are then passed on to consumers in the form of higher bills. Capital markets and the utility industry have undergone significant changes over the past 50 years since the early studies of utility capital ownership (Joskow 1972, 1974). In this paper we use new data to revisit these issues. We do so by exploring four main research questions. First, to what extent are utilities being allowed to earn excess returns on equity by their regulators? Second, what possible mechanisms can explain this divergence? Third, how have excess returns on equity affected utilities' capital investment decisions? Fourth, what impact has this had on the costs paid by consumers?

TAB 12

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

BY EMAIL

July 18, 2024

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Generic Proceeding – Cost of Capital and Other Matters
Return on Equity Value Requests – Updated
Ontario Energy Board File Number: EB-2024-0063

On July 12, 2024, OEB staff filed a letter with tables showing the reported 2023 regulated return on equity (ROE) values and deemed ROE values, for all electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation Inc. For comparison, the tables also showed the 2022 reported values.

Subsequent to filing this letter, OEB staff became aware of certain discrepancies in the tables. Please refer to the attached tables which show the changes made highlighted in bold (versus the July 12, 2024 version).

We trust this is of assistance to all parties. Any questions relating to this letter should be directed to Fiona O'Connell at fiona.oconnell@oeb.ca.

Yours truly,

Fiona O'Connell
Senior Advisor, Regulatory Accounting, Operations Decision Support

c: All Parties to EB-2024-0063

OEB Staff Tables – Return on Equity Values
Cost of Capital and Other Matters
EB-2024-0063
July 12, 2024 – Updated July 18, 2024

Table 1: Return on Equity for Electricity Distributors

Company Name	Year	Regulated ROE	Deemed ROE
Alectra Utilities Corporation	2022	6.70%	8.95%
Alectra Utilities Corporation	2023	7.55%	8.95%
Algoma Power Inc.	2022	10.53%	8.52%
Algoma Power Inc.	2023	10.54%	8.52%
Atikokan Hydro Inc.	2022	7.22%	8.78%
Atikokan Hydro Inc.	2023	19.16%	8.78%
Bluewater Power Distribution Corporation	2022	7.69%	8.98%
Bluewater Power Distribution Corporation	2023	10.29%	**9.36%**
Burlington Hydro Inc.	2022	7.39%	8.34%
Burlington Hydro Inc.	2023	8.11%	8.34%
Canadian Niagara Power Inc.	2022	8.47%	8.66%
Canadian Niagara Power Inc.	2023	7.90%	8.66%
Centre Wellington Hydro Ltd.	2022	9.33%	9.00%
Centre Wellington Hydro Ltd.	2023	11.42%	9.00%
Chapleau Public Utilities Corporation	2022	12.99%	8.98%
Chapleau Public Utilities Corporation	2023	-3.61%	8.98%
Cooperative Hydro Embrun Inc.	2022	15.94%	9.00%
Cooperative Hydro Embrun Inc.	2023	10.68%	**9.36%**
E.L.K. Energy Inc.	2022	-1.97%	8.66%
E.L.K. Energy Inc.	2023	-22.33%	8.66%
Elexicon Energy Inc.	2022	4.86%	9.43%
Elexicon Energy Inc.	2023	5.15%	9.43%
Enova Power Corp.	2022	8.07%	**8.43%**
Enova Power Corp.	2023	7.32%	**8.43%**
Entegrus Powerlines Inc.	2022	7.85%	9.19%
Entegrus Powerlines Inc.	2023	8.79%	9.19%
ENWIN Utilities Ltd.	2022	10.78%	8.52%
ENWIN Utilities Ltd.	2023	9.75%	8.52%
EPCOR Electricity Distribution Ontario Inc.	2022	0.75%	8.98%
EPCOR Electricity Distribution Ontario Inc.	2023	3.95%	9.36%
ERTH Power Corporation	2022	9.72%	9.00%
ERTH Power Corporation	2023	9.32%	9.00%
Essex Powerlines Corporation	2022	6.09%	9.00%
Essex Powerlines Corporation	2023	4.50%	9.00%

Festival Hydro Inc.	2022	9.25%	9.30%
Festival Hydro Inc.	2023	8.62%	9.30%
Fort Frances Power Corporation	2022	-2.31%	0.00%
Fort Frances Power Corporation	2023	0.19%	0.00%
GrandBridge Energy Inc.	2022	9.60%	8.86%
GrandBridge Energy Inc.	2023	11.20%	8.86%
Greater Sudbury Hydro Inc.	2022	10.52%	8.52%
Greater Sudbury Hydro Inc.	2023	8.24%	8.52%
Grimsby Power Incorporated	2022	8.42%	8.66%
Grimsby Power Incorporated	2023	6.63%	8.66%
Halton Hills Hydro Inc.	2022	8.19%	8.34%
Halton Hills Hydro Inc.	2023	8.71%	8.34%
Hearst Power Distribution Company Limited	2022	7.50%	8.34%
Hearst Power Distribution Company Limited	2023	8.12%	8.34%
Hydro 2000 Inc.	2022	-5.46%	8.52%
Hydro 2000 Inc.	2023	-11.09%	8.52%
Hydro Hawkesbury Inc.	2022	10.41%	9.00%
Hydro Hawkesbury Inc.	2023	0.64%	9.00%
Hydro One Networks Inc.	2022	10.10%	9.00%
Hydro One Networks Inc.	2023	10.88%	9.36%
Hydro Ottawa Limited	2022	6.94%	8.34%
Hydro Ottawa Limited	2023	6.15%	8.34%
InnPower Corporation	2022	12.82%	8.78%
InnPower Corporation	2023	10.04%	8.78%
Kingston Hydro Corporation	2022	6.76%	9.19%
Kingston Hydro Corporation	2023	7.92%	9.36%
Lakefront Utilities Inc.	2022	10.87%	8.66%
Lakefront Utilities Inc.	2023	4.27%	8.66%
Lakeland Power Distribution Ltd.	2022	11.82%	8.98%
Lakeland Power Distribution Ltd.	2023	11.02%	8.98%
London Hydro Inc.	2022	6.39%	8.66%
London Hydro Inc.	2023	7.05%	8.66%
Milton Hydro Distribution Inc.	2022	4.36%	9.19%
Milton Hydro Distribution Inc.	2023	10.66%	8.66%
Newmarket-Tay Power Distribution Ltd.	2022	7.29%	9.66%
Newmarket-Tay Power Distribution Ltd.	2023	7.60%	9.66%
Niagara Peninsula Energy Inc.	2022	8.83%	8.34%
Niagara Peninsula Energy Inc.	2023	9.81%	8.34%
Niagara-on-the-Lake Hydro Inc.	2022	8.79%	8.98%
Niagara-on-the-Lake Hydro Inc.	2023	7.80%	8.98%
North Bay Hydro Distribution Limited	2022	9.09%	8.34%

North Bay Hydro Distribution Limited	2023	11.05%	8.34%
Northern Ontario Wires Inc.	2022	9.06%	8.78%
Northern Ontario Wires Inc.	2023	4.44%	8.78%
Oakville Hydro Electricity Distribution Inc.	2022	9.17%	9.36%
Oakville Hydro Electricity Distribution Inc.	2023	9.90%	9.36%
Orangeville Hydro Limited	2022	5.71%	9.36%
Orangeville Hydro Limited	2023	8.25%	9.36%
Oshawa PUC Networks Inc.	2022	8.96%	8.34%
Oshawa PUC Networks Inc.	2023	9.50%	8.34%
Ottawa River Power Corporation	2022	10.59%	8.66%
Ottawa River Power Corporation	2023	3.84%	8.66%
PUC Distribution Inc.	2022	9.92%	9.00%
PUC Distribution Inc.	2023	7.96%	9.36%
Renfrew Hydro Inc.	2022	8.49%	8.78%
Renfrew Hydro Inc.	2023	5.75%	8.78%
Rideau St. Lawrence Distribution Inc.	2022	0.80%	8.66%
Rideau St. Lawrence Distribution Inc.	2023	4.88%	8.66%
Sioux Lookout Hydro Inc.	2022	11.05%	9.00%
Sioux Lookout Hydro Inc.	2023	11.45%	9.00%
Synergy North Corporation	2022	3.82%	8.85%
Synergy North Corporation	2023	4.74%	8.85%
Tillsonburg Hydro Inc.	2022	-0.32%	8.98%
Tillsonburg Hydro Inc.	2023	3.52%	8.98%
Toronto Hydro-Electric System Limited	2022	7.44%	8.52%
Toronto Hydro-Electric System Limited	2023	6.80%	8.52%
Wasaga Distribution Inc.	2022	10.85%	9.19%
Wasaga Distribution Inc.	2023	8.20%	9.19%
Welland Hydro-Electric System Corp.	2022	11.71%	8.78%
Welland Hydro-Electric System Corp.	2023	12.97%	8.78%
Wellington North Power Inc.	2022	12.01%	8.34%
Wellington North Power Inc.	2023	10.32%	8.34%
Westario Power Inc.	2022	5.09%	9.00%
Westario Power Inc.	2023	11.24%	9.00%

Table 2: Return on Equity for Electricity Transmitters

Company Name	Year	Regulated ROE	Deemed ROE
B2M	2023	10.09%	8.52%
NRLP	2023	10.33%	8.52%
HOSSM	2023	19.45%	9.19%
CNPI	2023	16.45%	9.30%

Five Nations	2023	N/A	N/A
Upper Canada Transmission 2	2023	9.31%	8.34%
Watay	2023	N/A	N/A
HONI TX	2023	10.80%	9.36%
B2M	2022	9.58%	8.52%
NRLP	2022	10.49%	8.52%
HOSSM	2022	17.54%	9.19%
CNPI	2022	14.22%	9.30%
Five Nations	2022	N/A	N/A
Upper Canada Transmission 2	2022	9.42%	8.34%
Watay	2022	N/A	N/A
HONI TX	2022	9.92%	8.52%

Table 3: Return on Equity for Natural Gas Utilities

Company Name	Year	Regulated ROE	Deemed ROE
Enbridge Gas	2023	7.07%	9.36%
Enbridge Gas	2022	9.45%	8.66%
EPCOR	2023	12.66%	8.98%
EPCOR	2022	10.43%	8.98%

Table 4: Return on Equity for OPG[1]

Company Name	Year	Regulated ROE	Deemed ROE
OPG	**2023**	To be reported	
OPG Nuclear	2023		8.66%
OPG Hydroelectric	2023		9.33%
OPG	**2022**	**12.68%**	
OPG Nuclear	2022	12.94%	8.66%
OPG Hydroelectric	2022	12.39%	9.33%

[1] OPG's 2023 ROE is due to be filed with the OEB on July 31, 2024. Please also refer to the EB-2024-0063, OPG Letter, July 17, 2024.

TAB 13

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.

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1 INTRODUCTION

1.1 Qualifications

This evidence is prepared by Dr. Sean Cleary, CFA of Queen's University. I am a Professor of Finance at the Smith School of Business at Queen's University. I earned my Ph.D. in Finance at the University of Toronto in 1998 and earned my CFA designation in 2001.

I provided expert evidence sponsored by the Industrial Gas Users Association (IGUA) in the 2023 EGI rebasing proceedings (EB-2022-0200). I have served as an expert witness on behalf of the Office of the Utilities Consumer Advocate of Alberta on several occasions including generic cost of capital proceedings in 2013-2014 (Proceeding ID 2191), 2015-2016 (Proceeding ID 20622), 2018 (Proceeding ID 22570), 2019-20 (Proceeding ID 24110), 2022-23 (Proceeding ID 27084), as well as the generic regulated rate option proceeding (Proceeding ID 2941) in 2014 and the EPCOR Energy Alberta 2018-2021 Energy Price Setting Plan proceeding (Proceeding ID 22357) in 2017. I also prepared evidence on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016, and in 2018.

In addition to this consulting work, my research has extensively involved examining corporate finance and cost of capital matters, consisting of over 30 publications. My work has been cited more than 5,600 times. Most of this work has dealt directly or indirectly with capital markets, capital structure, and cost of capital issues. I have authored or co-authored 14 finance textbooks, all of which deal with capital markets, capital structure, cost of equity, and cost of capital analysis. I examine capital market conditions and estimate the cost of capital for actual companies on a regular basis, which I use for teaching purposes. In addition, I previously worked as a commercial lender.

My CV is included as Attachment 1 to my evidence.

1.2 Purpose of Testimony

My evidence is sponsored by IGUA and the Association of Major Power Consumers in Ontario (AMPCO). In this capacity, I was asked to prepare expert testimony in relation to the Ontario Energy Board (OEB) Generic Proceeding on cost of capital and other matters (OEB-2024-0063). I was asked to review and consider the topics captured in the OEB`s approved issues list for this proceeding (excluding the cloud computing issue), and in the June 21, 2024 evidence of London Economics International (LEI) sponsored by OEB Staff.

I acknowledge that I have a duty to provide opinion evidence to the OEB that is fair, objective and non-partisan, and, further that my evidence would not change if I was retained by any other parties involved in this proceeding. A signed copy of the OEB's Form A, Acknowledgement of Expert's Duty, is included as Attachment 2 to this evidence.

2 EXECUTIVE SUMMARY

For ease of reference, I have organized Sections 2 and 3 of my evidence in alignment with the structure used by LEI in its evidence. This section provides a summary of my responses to the 22 issues identified in the OEB's Final Issues List for the Generic Proceeding, which compares my recommendations to the status quo and also to the recommendations of LEI, who provided its analysis of these issues on behalf of the OEB.

My analysis is consistent with the principles advocated by LEI in determining its recommendations, which are stated on page 12 of its evidence as copied below[1]:

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.

LEI notes on page 12 that it "proposes evolutionary rather than revolutionary changes in response to the issues identified in the Generic Proceeding." I would suggest that my recommendations would also be considered evolutionary, and I am in agreement with several of LEI's recommendations and existing OEB practices. I do provide recommendations that differ from (or build upon) LEI's recommendations and existing OEB practice on some of the issues – particularly with respect to dealing with the OEB's current ROE methodology, including an updated estimate of the base ROE, as well as suggesting other minor refinements to the existing ROE methodology. Accordingly, I will devote more attention in my evidence

[1] Where FRS refers to the Fair Return Standard.

to addressing the situations where I deviate or build upon LEI's recommendations or existing OEB practice.

The table below is a modified version of the one provided by LEI on pages 13-20 of its evidence and summarizes my responses to the 22 issues identified by the OEB, and provides a comparison to both the status quo and to LEI's recommendations.

Issue #	**Issue**	**Status Quo**	**LEI**	**Dr. Cleary**
A. General Issues				
1.	Should the approach to setting cost of capital parameters and capital structure differ depending on: a) The source of the capital (i.e., whether a utility finances its business through the capital markets or through government lending such as Infrastructure Ontario, municipal debt, etc.)? b) The different types of ownership (e.g., municipal, private, public, co-operative, not for profit, Indigenous / utility partnership, etc.)?	The OEB considers different funding sources (by considering actual debt interest rates in most cases) but does not consider the ownership structure.	• The OEB's existing methodology implicitly accounts for differences in sources of funding when approving rate applications. LEI recommends that this aspect of the OEB methodology be retained. • Consistent with the OEB's existing policy, the approach to setting the cost of capital parameters and capital structure should not depend on a utility's ownership structure. LEI believes the status quo is consistent with the FRS and Canadian Supreme Court judgement(s).	**1a) Maintain existing OEB methodology regarding sources of financing.** **1b) Maintain existing OEB policy of not considering ownership structure in determining cost of capital parameters.**
2.	What risk factors (including, but not limited to, the energy transition) should be considered, and how should these risk factors under the current and forecasted macroeconomic conditions be	• The recent risk assessments have considered business risks (energy transition risk, volumetric risk, operational risk, regulatory risk, and policy risk) and financial risk.	• The risk factors considered in recent equity thickness proceedings are sufficient. Business risk assessment can be performed based on changes in volumetric risk, operational risk, regulatory risk and policy risk (including energy transition risk).	**Maintain the OEB's current policy of reviewing business and financial risk factors if there is a perceived significant change from the status quo, and adjusting the allowed equity ratio as appropriate to address material changes in the utility risk profile.**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
	considered in determining the cost of capital parameters and capital structure?	• The OEB undertakes a full reassessment of a utility's capital structure in the event of significant changes in risks.	o The assessment of financial risks can focus on the utility's ability to continue attracting debt and equity financing at reasonable terms, primarily relying on assessing key credit metrics and their potential impact on credit ratings. • The current policy of considering the impact of risk factors when there is a significant change in business/financial risks is a reasonable approach and is recommended to be retained.	
3.	What regulatory and rate-setting mechanisms impact utility risk, and how should these impacts be considered in determining the cost of capital parameters and capital structure?	• LEI reviewed five major OEB policy initiatives since 2006. • The OEB considers regulatory risks during risk assessments associated with equity thickness proceedings.	• Any regulatory mechanism that can significantly impact the stability of future cash flows must be considered for review as part of regulatory risks. • The five major OEB policy initiatives since 2006 reviewed by LEI have slightly reduced the risks for electricity distributors. • The current policy of considering the impact of risk factors on request when there is a significant change in business/financial risks (including regulatory risk) is a reasonable approach, which LEI recommends be retained.	**Any regulatory mechanism that can significantly impact the stability of future cash flows must be considered for review as part of regulatory risks.** **The current policy of considering the impact of risk factors on request when there is a perceived significant change in business/financial risks (including regulatory risk) is a reasonable approach, which should be retained.** **In addition, I agree with LEI's recommendation that proactive impact assessments should occur following material regulatory changes.**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
			• In addition, LEI recommends proactive impact assessments ("IAs") before material regulatory changes.	
B. Short-term debt rate				
4.	Should the short-term debt rate for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be set using the same approach as set out in the OEB Report?	• For electricity distributors and transmitters, DSTDR is used to set short-term debt rates, using a formulaic approach. • For natural gas distributors and OPG, short-term debt rates are based on their actual debt portfolio.	The current DSTDR methodology (3-month BA rate plus a spread) is no longer appropriate as major Canadian banks will transition all existing financial products that reference CDOR/BAs to referencing Canadian Overnight Repo Rate Average ("CORRA") on or before June 28th, 2024.	**The current approach is reasonable in principle; however, the DSTDR methodology will have to be adjusted since the 3-month BA rate is no longer appropriate or available.**
5.	If no to Issue #4, how should the short-term debt rate be set?	N/A	• For reference rate, the average of 3-month CORRA futures rates be considered for the next 12-month period. • The spread for a R1-low rated utility over CORRA be determined from an annual confidential survey of banks (slightly modified from the status quo vis-à-vis larger sample size of 6-10 banks and limited exclusion of outliers). • DSTDR be applied as a cap for all utilities.	**- The CORRA should be used to replace the B/A rate in the DSTDR methodology.** **- LEI recommends extending the current practice of sampling 6 big banks to estimate the spread to a larger sample of 6-10 banks. I am fine with this suggestion, assuming that it does not lead to less reliable estimates (i.e., from the smaller banks), nor adds unnecessary complexity to the survey process.** **- LEI recommends estimating the base CORRA based on the average of 3-month CORRA futures rates over the next 12 months. Since the CORRA is linked directly to the Bank of Canada's rate**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
				decisions, I am fine with this suggestion; although, I would also be fine with using the existing CORRA rate as of September 30th of each year as the base CORRA rate.
C. Long-term debt rate				
6.	Should the long-term debt rate for electricity distributors, natural gas utilities, and OPG continue to be set using the same approach as set out in the OEB Report and as set out in the Staff Report for electricity transmitters?	• For natural gas distributors and OPG, the long-term debt rates are considered based on the weighted cost of actual embedded debts. • For electricity distributors and electricity transmitters, long-term debt rates primarily rely on embedded or actual cost for existing long-term debt instruments, albeit with the DLTDR calculated using a formulaic approach, acting as a proxy or a ceiling.	The current methodology is broadly appropriate but can be improved upon (see below).	The existing approach is appropriate, but I have some suggestions (discussed in response to Issue #7) that will improve its application (i.e., improve its accuracy of forecasts) and enhance the ease of application (i.e., reduce the estimation requirements and potential issues with using poor estimates).
7.	If no to Issue #6, how should the long-term debt rate be set?	N/A	• Reputable publicly available sources for 30-year bond yield forecasts for LCBF/risk-free rate be considered. • Bloomberg's BVCAUA30 BVLI Index (12-month trailing average) is appropriate for considering the spread over LCBF for an A-rated utility.	**- The DLTDR should be set as a cap for all utilities (including gas distributors and OPG) and not just electric T&Ds as is current practice.** **- Rather than using forecasts for LCBF in the existing formula, the Board should use the actual prevailing bond yields as of September 30th which produce more accurate (less biased)**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
			• DLTDR applied as a cap for all utilities.	**estimates of future 30-year Canada yields, and has the side benefit of being significantly easier to implement.**
8.	How should transaction costs incurred by utilities be considered when setting the long-term debt rate?	The utilities typically record the transaction costs as interest expense, amortizing them using the effective interest rate method over the term of the related debt instrument.	Transaction costs should be considered as operating expenses, as this approach is more suitable for the nature of the expense, which may fluctuate from year to year.	**The OEB should maintain its current practice of not considering transaction costs when determining the DLTDR/DSTDR, and should continue the practice of allowing utilities to record transaction costs as interest expense, which are amortized using the effective interest rate method over the term of the related debt instrument.**
9.	What are the implications of variances from the deemed capital structure (i.e., notional debt and equity) and how should they be considered in setting the cost of long-term debt?	• The OEB considers the deemed capital structure when determining the cost of capital. • For short-term debt, the OEB considers 4% for electricity distributors and transmitters and the unfunded portion of the capital structure for other utilities.	The status-quo approach (considering deemed capital structure regardless of the actual capital structure) is retained.	**The OEB should maintain the status quo.**
D. Return on equity				
10.	What methodology should the OEB use to produce a return on equity that satisfies the Fair Return Standard (FRS)?	• The base ROE was determined using the equity risk premium ("ERP") approach in 2009. • The ROE is updated annually using adjustment factors for long	• LEI recommends using the Capital Asset Pricing Model ("CAPM") to determine the base ROE (average estimate of 8.95%, low estimate of 8.23%, and a high estimate of 10.22%), as it meets the FRS.	**Maintain the existing ERP formula methodology, but make the following modifications:** **1. Update the base ROE to 7.05%.** **2. Update the base LCBF factor to the September**

Issue #	**Issue**	**Status Quo**	**LEI**	**Dr. Cleary**
		Canada bond forecast ("LCBF") and A-rated utility bond yield spread.	• The ROE should be updated annually using the adjustment factors (0.26 for LCBF and 0.13 for utility bond spread) determined simultaneously with multivariate regression analysis (as opposed to independent determination in 2009).	**30, 2024 actual yield on 30-year Canada bonds (I use the current yield of 3.30% as a placeholder in the revised equation below).** **3. Update the base UtilBondSpread value to the actual September 30, 2024 value (I use the current spread of 1.38% as a placeholder in the revised equation below).** **4. LCBF should be estimated as the actual yield on 30-year Canada bonds as of September 30th in the year preceding the test year.** **5. UtilBondSpread should be estimated as the actual spread on A-rated utility bond yields as of September 30th in the year preceding the test year.** **6. Change the existing adjustment factors for LCBF and UtilBondSpread from 0.5 to 0.75.** **- These recommendations result in the modified version of the current OEB formula presented below (with 3.30% and 1.38% serving as placeholders for the base LCBF and UtilBond Spread variables):** $\boldsymbol{ROE_t = 7.05\% + 0.75 \times (LCBF_t - 3.30\%) + 0.75 \times (UtilBondSpread_t - 1.38\%)}$

Issue #	Issue	Status Quo	LEI	Dr. Cleary
11.	Are the perspectives of debt and equity investors in the utility sector relevant to the setting of cost of capital parameters and capital structure? If yes, what are the perspectives relevant to that consideration, and how should those perspectives be taken into account for setting cost of capital parameters and capital structure?	• The allowed ROEs are legally required to meet the FRS, which is inherently designed to allow sufficient returns for the commensurate risk undertaken by the investors and ensure that the utilities continue to attract incremental capital at reasonable terms. • The DLTDR and DSTDR formulae are devised considering OEB-regulated entities' credit profiles.	• The OEB's current approach to cost of capital determination (including the determination of deemed capital structure) sufficiently considers investor perspectives, i.e., the allowed cost is commensurate with the perceived risks associated with the sector. • LEI believes that the existing approach meets the FRS.	**The current OEB approach satisfies the perspectives of both equity and debt investors and comfortably satisfies the FRS.**
E. Capital structure				
12.	How should the capital structure be set for electricity transmitters, electricity distributors, natural gas utilities, and OPG to reflect the FRS?	The OEB sets a uniform ROE for all regulated entities and adjusts the equity thickness in the capital structure based on business and financial risk assessment relative to the previous assessment.	• The OEB's current approach of revising the capital structure upon application if warranted due to increase in business/financial risks is a reasonable practice, as OEB has noted that risks rarely change meaningfully in a short period of time. • LEI believes that the existing approach meets the FRS. • Applicants should be required to include forward cash flow modeling and scenario analysis showing impact on credit metrics to support their case.	**- I concur with LEI's position that the OEB's current practice of setting a uniform ROE and adjusting the capital thickness if it determines upon application that there has been a meaningful change in business/financial risks is appropriate.** **- Applicants should be required to include forward cash flow modeling and scenario analysis showing impact on credit metrics to support their case.**
13.	Should the OEB take a different approach for setting the capital structure for	While the capital structure for transmitters is determined on a case by case basis,	• The current approach of allowing the same equity thickness to all electricity transmitters	**OEB should reconsider the capital structure for Hydro One given its predominance and in**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
	electricity transmitters depending on whether they are a single versus multiple asset transmitter?	the OEB has allowed a 40% equity thickness to all electricity transmitters since 2006 (same as electricity distributors).	(and distributors) should be maintained.	**accord with the factors that I discuss.**
F. Mechanics of implementation				
14.	What on-going monitoring indicators to test the reasonableness of the results generated by its cost of capital methodology should the OEB consider, including the monitoring of market conditions?	The OEB conducts an ongoing monitoring process through quarterly reports for internal review purposes only.	• Consistent with the OEB's existing policy, OEB staff should continue to monitor the cost of capital parameters and test their reasonableness in the context of prevailing macroeconomic conditions on a quarterly basis, through reports prepared for internal review purposes only.	**The OEB's current practice of continuous monitoring through the review of quarterly reports adds value and should be retained.**
15.	How should the OEB regularly confirm that the FRS continues to be met and that rate-regulated entities are financially viable and have the opportunity to earn a fair, but not excessive, return?	The OEB regularly confirms that the FRS is being met in its annual cost of capital update letters.	• The OEB should continue to annually confirm that the FRS is being met, as it currently does through its cost of capital update letters. • In addition, the OEB should direct utilities, as part of the annual reporting requirements, to provide credit ratings and details regarding new short-term and long-term debt and equity issued/borrowed during the year. • The OEB may use this information to monitor the credit ratings and pace of capital injections for the regulated utilities on an ongoing basis, as a further test of whether	**- Maintain the OEB's current annual review practice.** **- The current annual review process can be supplemented by adding annual requirements for utilities to provide credit ratings, as well as details regarding new short-term and long-term debt and equity issued/borrowed during the year.**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
			the FRS continues to be met.	
16.	What should be the timing of the OEB's annual cost of capital parameters updates, including the timing, as required, of the underlying calculations?	• The OEB updates the cost of capital parameters every year and publishes a letter with the updated parameters in October or November for rates taking effect in January or May of the following year. • The underlying calculations typically rely on data as of the end of September.	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 or May.	**Maintain the status quo, but consider changing to the use of October data rather than September data to update the ROE formula, if the OEB determined this change would not cause undue disruptions to its existing processes and procedures.**
17.	What should be the defined interval (for example, every three to five years) to review the cost of capital policy (including, but not limited to, a review of the ROE formula and the capital structure)? Should the OEB adopt trigger mechanism(s) for a review and if so, what would be the mechanisms?	• The OEB is to review the cost of capital policy every five years, as stated in the OEB's cost of capital report issued in 2009. • An applicant or intervenors can file evidence in individual rate hearings if they believe the cost of capital parameters are not reasonable. • Utilities under Price Cap IR or Annual IR Index rate-setting plans have an off-ramp mechanism.	• Consistent with the OEB's existing policy, the OEB should commit to reviewing the cost of capital policy every five years. • The OEB should also maintain the existing trigger mechanisms, including allowing utilities to apply for different cost of capital parameters during their individual rate hearings, as well as triggering a regulatory review through the off-ramp mechanism (which may or may not include a review of the cost of capital parameters) and/or capital structure. • In the event that a regulatory review is triggered, the utility and/or intervenors should be allowed to submit evidence for the OEB's consideration	**- I support regular reviews of the cost of capital policy (and allowed ROEs) at regular intervals (ideally every three years, but never more than five years).** **- The existing OEB trigger mechanisms and procedures that are in place are reasonable and should be retained.** **- In addition, I recommend that if the Canadian A-rated utility yield spreads exceed 2%, the OEB should undertake an immediate thorough assessment of existing capital market conditions, which could potentially lead to a full regulatory review, depending on the results of this assessment.**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
			regarding the extent to which the cost of capital parameters and/or capital structure caused or contributed to triggering the off-ramp. The OEB can then exercise its own judgement (based on the evidence presented) as to whether the cost of capital parameters and/or capital structure are to be included in the regulatory review.	
18.	How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?	Changes in cost of capital parameters and capital structure are implemented once a utility files its cost of service application.	Consistent with the OEB's existing policy, the OEB should continue to implement changes in the cost of capital parameters and capital structure upon rebasing.	**I support the status quo.**
19.	Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?	Utilities only transition to the new cost of capital parameters and capital structure once they file their cost of service application, not in the middle of an approved rate term.	• Consistent with the OEB's existing policy, the OEB should continue to implement changes in the cost of capital parameters and capital structure upon rebasing. • However, to ensure the FRS continues to be met, the OEB should also introduce an option for parties to request implementation of such changes prior to rebasing, so long as the two-factor test is met – (i) the utility should have more than 60% of its rate term remaining, and (ii) deviations in the cost of capital parameters should be	**I support maintaining the current OEB approach, but also incorporating the additional option recommended by LEI.**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
			material (100 bps or more).	
G. Other issues (prescribed interest rates)				
20.	Should the prescribed interest rates applicable to deferral and variance accounts (“DVAs”) and the construction work in progress (CWIP) account for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be calculated using the current approach?	The OEB uses a formulaic approach to setting prescribed interest rates for DVAs and CWIP.	• The current methodology for DVAs is no longer appropriate. • The current methodology for CWIP should be retained.	– **- Modify the existing practice for DVAs, as discussed in response to Issue #21.** **Maintain the current approach regarding estimating the prescribed interest rate for CWIP.**
21.	If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?	N/A	• For DVAs, LEI recommends aligning the prescribed interest rate with the revised calculation methodology recommended by LEI for the DSTDR – namely: o For the reference rate, LEI recommends considering the average of 3-month CORRA futures rates for the next 12-month period o The spread for a R1-low rated utility over CORRA should be determined via an annual confidential survey of banks (slightly modified from status quo vis-à-vis a larger sample size of 6-10 banks and no exclusion of outliers) • For CWIP, LEI recommends continuing	**The prescribed interest rate for DVAs should be revised to align with the recommended DSTDR methodology by using CORRA as the base rate instead of the B/A rate, where the base CORRA rate is estimated as the average of 3-month CORRA futures rates over the next 12 months, and the spread added to it is determined by sampling 6-10 banks to determine the appropriate R1-low rated utility spread.**

Issue #	**Issue**	**Status Quo**	**LEI**	**Dr. Cleary**
			the current approach of basing the prescribed interest rate on the FTSE Canada Mid Term Bond Index All Corporate yield for all construction projects, regardless of duration LEI also recommends continuing the current CWIP accounting procedures as set out in Article 220 (p. 200) and Article 410 (p. 27-28) of the OEB's *Accounting Procedures Handbook for Electricity Distributors.*	
H. Other issues (cloud computing deferral account)				
22.	Should carrying charges and/or another type of rate apply to the Cloud Computing deferral account? If so, what rate should be applied?	The OEB treats the cloud computing deferral account as a regular DVA account.	• LEI believes a deemed WACC is necessary as a means of aligning incentives for utilities to transition to cloud computing solutions. • LEI recommends that the OEB employ a deemed capital additions approach, which allows deemed WACC on the unamortized portions of the cloud computing contracts.	**I have not been asked to consider this issue.**

3 ISSUES IDENTIFIED IN THE OEB "ISSUES LIST"

3.1 Impact of source of the capital and types of ownership on the cost of capital

<u>Issue 1:</u> Should the approach to setting cost of capital parameters and capital structure differ depending on:

*a) The **source of the capital** (i.e., whether a utility finances its business through the capital markets or through government lending such as Infrastructure Ontario, municipal debt, etc.)?*

*b) The **different types of ownership** (e.g., municipal, private, public, co-operative, not for profit, Indigenous / utility partnership, etc.)?*

With respect to 1a), OEB's current practice of using actual debt rates in most cases considers the impacts of different funding sources, as noted by LEI. However, the deemed long-term debt rate (DLTDR) can be used as an estimate or a ceiling (if the actual rate is higher than DLTDR). This approach satisfies the FRS, is intuitive, and is easy to apply, and I agree with LEI that there is **no need to make changes** to this practice.

With respect to 1b), OEB's current policy is that ownership structure should not be a relevant consideration in determining a utility's cost of capital parameters. I agree with LEI's conclusion on page 52 of its evidence that:

> Allowing uniform ROE regardless of ownership is also consistent with the comparable investment standard of the FRS. The comparable return standard requires the allowed ROE to be *comparable to the return available from the application of invested capital to other enterprises of like risk.* The comparable investment standard implies risk determination based on the utilities' business/investment activities, and not the ownership type.

In particular, on page 52 of its evidence (bold added for emphasis, footnote omitted) LEI notes:

> As such, regulated utilities within a particular sector face very similar risks, given:
>
> • the composition of their rate bases is similar, i.e., the type of physical assets owned does not vary significantly. As such, electric distributors are commonly grouped as peer utilities when determining the appropriate rate of return; and
>
> • they operate in the same regulatory environment. For instance, all Ontario electric distributors' rates are governed by the same OEB regulations and principles, allowing them equal opportunities to recoup their operating costs.

Allowing some utilities to earn a higher return despite engaging in business activities of similar risk **would violate the comparable return standard**.

My recommendations (which align with LEI) are :

1a) Maintain existing OEB methodology regarding sources of financing.

1b) Maintain existing OEB policy of not considering ownership structure in determining cost of capital parameters.

3.2 Risk factors to be considered in determining the cost of capital parameters and capital structure

***Issue 2: What risk factors** (including, but not limited to, energy transition) **should be considered**, and **how should these risk factors** under the current and forecasted macroeconomic conditions **be considered in determining the cost of capital parameters and capital structure**?*

The OEB sets a uniform ROE for regulated entities, but engages in a reassessment of a utility's capital structure in the event of perceived significant changes in the company's business and/or financial risk, such as during the most recent Enbridge Gas rebasing application in 2023 (EB-2022-0200), which I was involved in.

Appropriately, this process involves a complete reassessment of the utility's business and financial risk, with the recognition that some macroeconomic conditions such as interest rates and yield spreads are already reflected in the allowed ROEs to some extent, as they are embedded in the OEB ROE formula. In addition, and as noted by LEI on page 53 of its evidence: "While energy transition risk has been specifically mentioned in Issue 2, one can reasonably argue that it is part of business risk, which can ultimately impact the bottom line (i.e., leading to a change in financial risks/returns)."

LEI notes on page 53 of its evidence that business risks "are related to uncertainty surrounding a company's operating earnings," while "financial risks are primarily linked to a company's ability to continue to finance its capital needs and growth opportunities by attracting investors at reasonable terms."

LEI further notes that during recent related proceedings, business risks have been grouped into the following business risk categories: 1. energy transition risk; 2. volumetric risk; 3. operational risk; 4. regulatory risk; and, 5. policy risk. This breakdown is reasonable and is reasonably consistent with the categories observed in debt rating reports; although I would note that such proceedings would by nature deal with other risks that may rise which may not fall "neatly" into one of these categories (although most if not all most probably could). Further, and also as noted by LEI on page 55 of its evidence, "the assessment of financial risks has focused on the utility's ability to continue to attract debt and equity financing at reasonable terms." Such analysis typically involves an assessment of widely used credit metrics, such as the ones used by debt rating agencies including S&P, Moody's, Fitch and DBRS Morningstar, as also discussed by LEI. Certainly, these were the main categories of business risk and the approach taken to financial risk assessment that were examined during the 2023 Enbridge Gas proceedings that I was involved in – and appropriately so.

I agree with LEI's recommendation on page 62 of its evidence that "the OEB's current policy (reviewing business/financial risk factors if there is a significant change from the status quo) be retained. Furthermore, LEI believes that adjusting the allowed /deemed equity thickness remains the appropriate lever to address material changes in the utility risk profile." As LEI points out on page 62 of its evidence: "LEI's recommendation to retain the status quo is consistent with the principles outlined by LEI in Section 3.1 as it meets the FRS by factoring the risk factors that may materially impact future utility cash flows, it is simple to administer as a complete review of business/financial risks is required only when the change in risk profile is perceived to be significant, and provides confidence to all stakeholders regarding the durability of the methodology by continuing with the status quo."

My recommendations (which align with LEI) are :

> 2) Maintain the OEB's current policy of reviewing business and financial risk factors if there is a perceived significant change from the status quo, and adjusting the allowed equity ratio as appropriate to address material changes in the utility risk profile.

3.3 Key regulatory and rate-setting mechanisms impacting utility risk

Issue 3: What regulatory and rate-setting mechanisms impact utility risk, and how should these impacts be considered *in determining the cost of capital parameters and capital structure?*

LEI provides an excellent summary of the OEB's current regulatory and rate-setting mechanisms, which they conclude have generally worked well and have served to reduce the risk for Ontario utilities. Their review includes a discussion of five policy initiatives that have been introduced since 2006 that includes: 1. Customer Choice Initiative deferral account; 2. Broadband deferral account; 3. Getting Ontario Connected Act (GOCA) variance account; 4. Low-income Energy Assistance Program Emergency Financial Assistance (LEAP EFA) deferral account; and, 5. Cloud Computing deferral account.

LEI also discusses the 2012 Renewed regulatory framework for electricity (RRFE), which focused on reforming the regulatory framework concerning three policies: 1. rate-setting (which introduced three IR mechanisms for the utilities to choose from: a) 4th generation IR or price cap IR; b. Custom IR; or, c. Annual IR index); 2. planning; and, 3. measuring performance.

I concur with LEI that regulatory mechanisms can play a valuable role in stabilizing utilities' cash flows and thereby affecting their business and financial risks. In fact, these regulatory mechanisms are one of several factors that are considered by debt rating agencies in their business risk assessment of utilities. As noted by LEI on page 74 of its evidence: "With respect to the major OEB regulatory mechanisms introduced since 2006, LEI believes that they have generally reduced the risks for electricity distributors." This conclusion is supported by the ranking of regulatory support provided by S&P as of November 2023 (as included in Figure 47 on page 129 of LEI's evidence), which shows the OEB ranked as one of just 10 jurisdictions (out of 60) that was ranked in the top category of "Most credit supportive (strong)," recognizing that of course other considerations play an important role in such a ranking.

As noted by LEI on page 74 of its evidence: "The examples reviewed by LEI in Section 4.3.2 indicate that rating agencies consider a number of regulatory mechanisms and factors to assess regulatory risks. However, they primarily rely on assessing how these mechanisms affect the stability of future utility cash flows." Therefore, I agree with LEI's recommendation on page 74 of its evidence that: "any regulatory mechanism that can significantly impact the stability of future cash flows must be considered for review as part of regulatory risks."

My recommendations in this respect are in total agreement with those of LEI:

> 3) - Any regulatory mechanism that can significantly impact the stability of future cash flows must be considered for review as part of regulatory risks.

- The current policy of considering the impact of risk factors on request when there is a perceived significant change in business/financial risks (including regulatory risk) is a reasonable approach, which should be retained.
- Proactive impact assessments should occur following material regulatory changes.

3.4 Short-term debt rate – appropriateness of existing methodology

***Issue 4: Should the short-term debt rate** for electricity transmitters, electricity distributors, natural gas utilities, and OPG **continue to be set using the same approach** as set out in the OEB Report?*

For electricity transmitters and distributors (T&D), the deemed short-term debt rate (DSTDR) is used to set short-term debt rates, while the short-term rates applied for natural gas distributors and OPG are based on these utilities' forecasts of short-term debt rates based on their actual debt portfolio. In addition, for electricity T&D, the DSTDR applies to 4% of their capital structure.

The current OEB policy is to determine the DSTDR based on estimates of the spread of a typical short-term loan for an R1-low utility over the 3-month Bankers Acceptance (BA) rate based on a confidential survey of up to 6 major Canadian banks (after eliminating the high and low estimates). The OEB generally calculates the 3-month BA rate used as the September average rate. As LEI points out, this practice must be changed since the BA rate will no longer be available, and Canadian banks are transitioning (and/or have already transitioned) to short-term debt products that are based on the Canadian Overnight Repo Rate Average (CORRA).

My recommendation is similar to that of LEI:

4) The current approach is reasonable in principle; however, the DSTDR methodology will have to be adjusted since the 3-month BA rate is no longer appropriate or available.

3.5 Short-term debt rate – recommended revisions to existing methodology

Issue 5: If no to Issue #4, how should the short-term debt rate be set?

LEI recommends changing the base reference rate for determining the DSTDR from the BA rate to the CORRA. I agree with this recommendation, since the BA rate will no longer be available and because Canadian Financial Institutions are transitioning short-term lending products to this reference rate.

LEI further recommends estimating the spread for an R-1 rated borrower to this rate based on a confidential survey of banks, which they recommend should be extended from the current sample of 6 to a larger sample of 6-10 banks. I am fine with this suggestion, assuming that it does not lead to including less reliable estimates (i.e., from the smaller banks) nor adds unnecessary complexity to the survey process. If either of these issues come to fruition, then the current practice of surveying Canada's large 6 banks is very representative of the Canadian market, since they dominate the Canadian banking industry.

On page 82 of its evidence, LEI further recommends estimating the base CORRA to be used in the DSTDR (to replace the BA rate) based on the "average CRA (3-month CORRA futures) determined over the relevant forward-looking 12-month period." They further suggest that using the futures rates will be "more representative of investor expectations of short-term rates over the next year, in line with potential BoC policy rate reduction expectations." Generally, I am against using interest rate "forecasts" or futures rates versus actual rates (which provide more accurate forecasts), as I will discuss in response to Issue 7, based on evidence provided in Appendix A. However, since the CORRA is linked directly to the Bank of Canada's rate decisions, I am fine with this suggestion; although, I would also be fine with using the existing CORRA rate as of September 30th of each year (as opposed to an average of the rate over the month – which is consistent the OEB's current policy of estimating the base BA as the September average). If the Board decides to continue the practice of using the existing rates rather than futures rates, using the month-end rate should be a better estimate of future rates than using an average for the month. Consider for example if the Bank of Canada unexpectedly cut its policy rate in the middle of a given month. This would lead to a decrease in CORRA, which may continue near the new level for some time, but would not have been reflected in the CORRA rates during the first half of the month (i.e., since it was unexpected). Therefore, in this instance using the rates during the first half of the month in estimating an average CORRA would bias the base rate upwards.

My recommendation is similar to that of LEI, with two minor qualifications:

5) - The CORRA should be used to replace the BA rate in the DSTDR methodology.

- LEI recommends extending the current practice of sampling 6 big banks to estimate the spread to a larger sample of 6-10 banks. I am fine with this suggestion, assuming that it does not lead to including less reliable estimates (i.e., from the smaller banks), nor adds unnecessary complexity to the survey process.

- LEI recommends estimating the base CORRA based on the average of 3-month CORRA futures rates over the next 12 months. Since the CORRA is linked directly to the Bank of Canada's rate decisions, I am fine with this suggestion; although, I would also be fine with using the existing CORRA rate as of September 30th of each year as the base CORRA rate.

3.6 Long-term debt rate – appropriateness of existing methodology

Issue 6: Should the long-term debt rate for electricity distributors, natural gas utilities, and OPG continue to be set using the same approach as set out in the OEB Report and as set out in the Staff Report for electricity transmitters?

The OEB currently applies the weighted average of actual embedded long-term debt costs to natural gas distributors and OPG, as well as to electric T&D, but uses the DLTDR as a proxy or a ceiling for electric T&D utilities. The OEB currently sets the DLTDR equal to the Long Canada Bond Forecast (LCBF) obtained from Consensus forecasts plus the average Canadian A-rated utility yield spread, which is estimated as the average from the September preceding the test year. The LCBF is estimated by using the average of the 3-month and 12-month 10-year Government of Canada bond yield forecasts, and adding to this forecast the average of the actual observed spreads between 10-year and 30-year Government of Canada bond yields for each business day in the month of the Consensus Forecasts that are used (usually September).

The approach is sound, and **my recommendation is similar to that of LEI, with two minor qualifications:**

6) The existing approach is appropriate, but I have some suggestions discussed in response to Issue #7 that will improve its application (i.e., improve the accuracy of the forecasts) and enhance the ease of application (i.e., reduce the estimation requirements and potential issues with using poor estimates).

3.7 Long-term debt rate – recommended changes to existing methodology

Issue 7: *If no to Issue #6,* ***how should the long-term debt rate be set****?*

LEI recommends that the DLTDR be set as a cap for all utilities (including gas distributors and OPG) and not just electric T&Ds as is current practice. I agree with this suggestion. As LEI states on page 93 of its evidence: "All OEB-regulated entities reviewed have a similar senior debt credit rating, and there is no reason to only subject electricity distributors and transmitters to a cap."

With respect to the current DLTDR methodology, I have two suggestions that differ from both the existing OEB approach and LEI's recommendations for refining that approach. Currently the OEB estimates the LCBF based on 10-year yield consensus forecasts, and estimates a spread that it adds to estimate 30-year Canada yields. LEI recommends relying on published forecasts of Canada 30-year yields, which has the benefit of not having to estimate the spread between 10- and 30-year Canada yields, which varies through time and is difficult to forecast. While the LEI recommendation is an improvement, I provide evidence in Appendix A that demonstrates, using Canadian data over the 2011-2023 period, that using existing 30-year yields produces **statistically significantly more accurate forecasts** of actual 30-year yields in the subsequent period than using forecasts. For example, while the average actual 30-year government yield over the period was 2.57%, the average of September consensus forecasts was 0.37% higher at 2.94%. These figures indicate an **upward bias** over this 13-year period of **about 0.4%**, which is substantial. In contrast, the average forecast yields using the previous actual September 30th yields was 2.58% – virtually the same as the average for the actual prevailing yields of 2.57%. In other words, using Consensus forecasts would have added an average excess amount of 0.4% to DLTDR (and the allowed ROE of 0.2% - that is borne by the consumer when used in the OEB formula), whereas using actual prevailing 30-year Canada yields at the start of the period would have been **unbiased** on average.

Appendix A also discusses supporting research which confirms that using existing rates would have produced better estimates of future rates than using economist forecasts based on empirical research that considered other jurisdictions and during different time periods. For example, a study by Hafer and Hein (1989)[2] shows that economic forecasters do not perform any better than using futures rates, and perform **worse** than naïve forecasts (i.e., simply using the existing rates). Similarly, a 2005 study by Mitchel and Pearce (2007)[3] found that: "Most economists' forecast accuracy is statistically indistinguishable from a random walk model in forecasting the Treasury bill rate, but many are significantly worse in forecasting the Treasury bond rate and the exchange rate."[4] Yet another study by Spiwoks, Bedke and Hein (2008)[5] examined 10-year US government bond yield and three-month US Treasury bill rate forecast accuracy for the 1989 to 2004 period and concluded that "sign accuracy is significantly better than random walk forecasts in only a very few of the forecast time series." This indicates forecasters are not very successful in even simply forecasting the direction of future interest rates. Not surprisingly, they further find that "the information content of most of the forecast time series is lower than that of the naïve forecasts."

Based on this evidence, I recommend that rather than using forecasts to estimate LCBF, the Board should use the actual prevailing bond yields, and I further recommend using the actual prevailing rate as of September 30 of the preceding the test year, which should be a better estimate of future rates than using an average for the month of September. Consider for example if unexpectedly high inflation figures were reported in the middle of a given month that led to expectations of higher future inflation rates. This would generally lead to a bump in bond yields, which may continue at the new level for some time, but would not have been reflected in the yields during the first half of the month (i.e., since it was unexpected). Therefore, using the yields during the first half of the month in an average could bias the base rate estimate downward (in this case). My recommended approach also has the added benefit that it is easier to implement, since it does not require yield forecasts, estimating the spread between 10- and 30-year Canada yields, or even obtaining bond yield data for an entire month. Estimating the spread between 10- and 30-year Canada yields is not a trivial matter and is fraught with uncertainty. For example, while this spread averaged +0.38% over the 2004-2023 period, it has been as low as -0.23% and as high as +0.81%, and sat at -0.08% on June 5, 2024.

[2] This article is appended to my evidence as Attachment AA.
[3] This article is appended to my evidence as Attachment AB.
[4] The random walk model is equivalent to using naïve forecasts, as defined above.
[5] This article is appended to my evidence as Attachment AC.

My recommended modifications to the current OEB practice are:

7) - The DLTDR should be set as a cap for all utilities (including gas distributors and OPG) and not just electric T&Ds as is current practice.

- Rather than using forecasts for LCBF in the existing formula, the Board should use the actual prevailing bond yields as of September 30th which produce more accurate less biased estimates of future 30-year Canada yields, and has the side benefit of being significantly easier to implement.

3.8 Long-term debt rate – transaction costs incurred by utilities

Issue 8: *How should* ***transaction costs incurred by utilities*** *be considered when setting the long-term debt rate?*

As LEI states on page 93 of its evidence: "The OEB currently does not consider transaction/financing costs associated with obtaining debt when determining the DLTDR/DSTDR. The utilities reviewed by LEI record the transaction costs as interest expense, amortizing them using the effective interest rate method over the term of the related debt instrument."

This practice seems reasonable to me since it embeds the actual costs of debt financing related to new debt issues into the cost of debt, as they should be. The fact that most companies (utilities and other businesses alike) do not frequently issue new debt does not detract from the fact that such issuing costs have a legitimate impact on their actual embedded debt financing costs when they do occur. In fact, it is consistent with the OEB's approach of adding transaction costs of 0.5% to the cost of equity, even though firms rarely engage in new equity issuances (which effectively includes the 0.5% in this long-term required equity return estimate). As such, I believe the OEB's current practice is appropriate, contrary to LEI's suggestion that these costs be included in operating costs.

My recommendation is:

8) The OEB should maintain its current practice of not considering transaction costs when determining the DLTDR/DSTDR, and should continue the practice of allowing utilities to record transaction costs as interest expense, which are amortized using the effective interest rate method over the term of the related debt instrument.

3.9 Long-term debt rate – implications of variances from the deemed capital structure

Issue 9: *What are the* ***implications of variances from the deemed capital structure*** *(i.e., notional debt and equity) and* ***how should they be considered*** *in setting the cost of long-term debt?*

As stated by LEI on page 96 of its evidence: "The OEB considers the deemed capital structure when determining the cost of capital. For rate-setting purposes, the *notional debt is used as the "plug" to true up actual debt to the allowed debt thickness."* Otherwise utilities could increase their equity thickness above allowed limits, the cost of which would be borne by consumers. Concurrently, the OEB also allows utilities the flexibility to adjust their actual capital structure based on their specific circumstances. In addition, as mentioned previously, the OEB uses 4% as a proxy for the short-term debt component for electricity T&D, which it also uses for the unfunded portion of the capital structure for other utilities.

I agree with LEI's comments on page 100 of its evidence that support "continuation of the status-quo approach (consider deemed capital structure regardless of the actual capital structure). This ensures fairness to both the utilities (flexibility to optimize the capital structure based on firm-specific needs) and the consumers (by limiting the deemed share of equity, which has a higher financing cost than debt)." I further agree with LEI's assertion on page 101 of its evidence that: "The status quo approach is also administratively simple for the OEB while maintaining a balance of fairness for the utilities and consumers, consistent with the principles outlined by LEI in Section 3.1. As the deemed capital structures are intended to, upon application and approval, track significant changes in the sector risk profile, this also meets the FRS."

My recommendation on this topic, which is in alignment with that of LEI, is:

9) The OEB should maintain the status quo.

3.10 Return on equity – recommended revisions to existing methodology in accordance with the FRS

Issue 10: *What methodology should the OEB use to produce a* ***return on equity that satisfies the Fair Return Standard (FRS)****?*

As noted by LEI on page 101 of its evidence: "The OEB must legally adhere to the FRS when setting the ROE." LEI provides the following summary of the well-known FRS on page 101 of its evidence:

> 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**.**

In accordance with the FRS, the OEB has used the following ROE methodology since 2009, which LEI summarizes nicely on page 102 of its evidence (footnote omitted, bold added for emphasis):

> The ROE is calculated using a base ROE of 9.75% (set in 2009) plus a LCBF spread and a utility bond spread, subject to an adjustment factor of 0.5, as shown earlier in Figure 3.
>
> The values for base ROE, base LCBF, and base utility bond spread were set as below:
>
> $$\boldsymbol{ROE_t = 9.75\% + 0.5 \times (LCBF_t - 4.25\%) + 0.5 \times (UtilBondSpread_t - 1.415\%)}$$
>
> The OEB adjusts the ROE annually by adjusting LCBF and utility bond spread based on current data. The following are however fixed: (i) Base ROE; (ii) LCBF adjustment factor; (iii) Utility bond spread adjustment factor; (iv) base LCBF; and (v) base A-rated utility bond yield spread.

Similar to LEI's recommendation, I support this general approach of continuing to use this equity risk premium based model (with adjustments) and applying it on an annual basis, as has been done in the past. LEI recommends adjustments to the five factors included in the model as noted above, which I discuss in turn before providing my alternative recommendations.

3.10.1 Base ROE

I agree with LEI that it makes sense for the OEB to take this opportunity to update the base ROE from the 9.75% established in 2009, to a base ROE that reflects current capital market conditions. LEI recommends that the base ROE be set at 8.95%, which equals their CAPM average estimate. They also consider alternative approaches to estimate the base ROE. Of course, the base ROE should be set equal to a utility's required cost of equity (Ke) at the time it is set, which satisfies the FRS, and is also consistent with the Office of the Auditor General of Ontario's recommendations to the OEB, which notes that rate-regulated entities should remain "financially viable and earn a fair, but not excessive, return."[6] If the allowed ROE exceeds Ke, this implies the utilities have the ability to earn excess economic rents, as discussed below in my evidence.

While LEI relies entirely on its CAPM estimates, I believe it is informative to discuss some of the other approaches they use in estimating Ke, even though LEI correctly disregards these estimates.

<u>LEI's ERP Analysis:</u>

On page 113 of its evidence, LEI estimates Ke = 8.65% using what it refers to as an equity risk premium (ERP) approach, which adds an estimate of ERP to the base LCBF. LEI's estimate is determined using 3.15% as the LCBF, which is based on March 2024 forecast long-term Canada yields. As discussed in detail in Section 3.7 above, and in Appendix A, I disagree with the use of forecast yields versus using actual prevailing yields. This applies to any approach taken to estimating Ke, as well as to estimating LCBF for the OEB ROE formula. I do note that 3.15% is very close to the actual 30-year government yield of 3.30% as of June 5, 2024 (which I use in my CAPM estimates), so the difference in this particular situation is very minimal (although this will not always be the case).

LEI estimates an ERP of 5.5%, which is the mid-point of the average of the 2001-24 actual returns on the S&P/TSX Index (of 6.77%), and the average returns on the BMO equal weight utilities index (of 10.98%). While I agree that historical returns do provide useful guidance in estimating future market returns, relying solely on historical evidence over such a short time period, will not always provide reliable estimates of future returns, which of course is what we are trying to estimate. I would also note that LEI's analysis includes the superior returns earned by Canadian utility stocks over this period relative to the broader market. Several factors could have contributed to this, including the fact that allowed ROEs in Canada have not declined in step with the significant declines in bond yields since 2004 as I demonstrate in Section 5.1 of

[6] Source: Office of the Auditor General of Ontario. *Value-for-money audit: Ontario Energy Board: Electricity oversight and consumer protection*. November 2022. Page 41.

my report, and which I discuss in greater detail below. This time period also includes a period of extremely low interest rates (from 2009 until 2022), which is positive for utility stock returns, since they are generally high dividend-paying stocks. In addition, during the 2001-24 period, there were three periods of extreme market declines and uncertainty, due to the technology crash (2001-02), the financial crisis (2008-09) and COVID (2020), and during such periods utility stocks tend to perform better than the average stock in the market due to their low-risk nature (i.e., there is a flight to safety). As such, I agree with LEI's decision to not consider this Ke estimate in their final ROE estimate.

<u>LEI's Discounted Cash Flow (DCF) Analysis:</u>

In order to apply its DCF analysis to estimate Ke, LEI forms three proxy sample groups – Generation (5 utilities – all U.S. based); Electric T&D (9 utilities – 8 U.S. based); and Gas Distribution (9 utilities – 7 U.S. based). Therefore, LEI examines a total of 23 utilities, 20 of which are U.S. based. I have argued during several previous cost of capital proceedings, including during the Enbridge Gas (EG) rebasing application (EB-2022-0200) in 2023 that U.S. utilities are NOT reasonable comparators for Canadian utilities. 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. Appendix B reproduces the analysis included in Sections 4.1 and 4.2 (pages 15-20) of my 2023 evidence prepared for the Enbridge Gas (EG) rebasing application (EB-2022-0200), which provides empirical support for the fact that U.S. utilities have higher business risk than Canadian utilities (using EG as an example in this case). The evidence in Appendix B is further supported by evidence provided in Appendix C with respect to utility beta estimates in Canada and the U.S. In particular, Appendix C shows that over a long period of time, U.S. utility beta estimate historical averages are **much, much higher** than (i.e., **almost double**) the comparable Canadian beta estimates, and that this difference is even more pronounced after accounting for the higher leverage of Canadian utilities. As a measure of market risk, the fact that U.S. utilities have much higher beta estimates than their Canadian counterparts supports the conclusions of my empirical business risk analysis presented in Appendix B. In short, LEI's DCF analysis is flawed by its heavy reliance on data for U.S. utilities rather than Canadian utilities.

The Gas Distribution group used by LEI also includes Enbridge Inc. which is also a questionable comparator due to the nature of its operations. It has an outlier dividend yield of 7.3% (versus the average of 4.2% for this group) and an above-average Ke estimate of 13.0% (versus the group average of 10.56%). I would further note that in a November 12, 2022 Memorandum sent by the Alberta Utilities Commission (AUC) to all parties involved in the 2024 Alberta Generic Cost of Capital (GCOC) Proceedings (27084), the AUC (Paragraph 15a, page 4) rejected Enbridge Inc. as a reasonable comparator for Alberta utilities, which reflected the majority of parties' opinions in that Proceeding:

> Inclusion of TC Energy Corporation and Enbridge Inc. – The Commission has determined that the comparator group will *not* include TC Energy Corporation and Enbridge Inc. Integration of these companies would be inconsistent with the Commission's prior approach for determining ROE.[16] Furthermore, the associated business risk, form of regulation and comparability of the two companies is not representative of that for regulated transmission and distribution utilities under the Commission's jurisdiction. The majority of parties took a similar position in their November 2, 2022, submissions.
>
> Footnote 16: Decision 22570-D01-2018: 2018 Generic Cost of Capital, Proceeding 22570, August 2, 2018, paragraph 273.

In addition to the sampling issues noted above, I note that LEI uses analyst forecasts provided by S&P Capital IQ in their single-stage DCF estimates that produce average growth forecasts of 10.26%, 6.41% and 6.34% for their Generation, Electricity T&D, and Gas Distribution proxy groups respectively, which leads to ROE estimates of 11.52%, 10.53% and 10.56% respectively.[7] These growth rates greatly exceed my estimates of future nominal GDP growth of 3.3-4.3%, which are based on both expert forecasts and historical data. As discussed in Section 5.3 of my evidence, analyst estimates are known to be overly optimistic and will lead to invalid estimates of Ke when using DCF models. For example, a study by Easton and Sommers[8] estimates that the "optimism" bias in analysts' growth forecasts inflates final DCF

[7] Individual company growth estimates were as high as 15.3%, which is clearly an even more unreasonable long-term growth expectation to infinity.

[8] Source: Easton, Peter D., and Gregory A. Sommers. "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts." Journal of Accounting Research 45 no. 5 (December 2007), pp. 983-1016.

cost of equity estimates by an average of 2.84%. In particular, the use of these overly optimistic growth forecasts often leads to adopting expected future growth rates (to infinity as implied by the single-stage DCF model) for utilities' earnings and dividends that exceed expected growth in the economy (i.e., nominal GDP growth). This is simply not realistic for mature, stable operating utilities operating within a defined region. Appendix D of my evidence provides strong support for these assertions.

As a result of the sampling and growth estimation issues identified above, I conclude that LEI's DCF estimates of Ke are upward biased and should not be relied upon, which is in agreement with LEI's decision not to include these estimates in their final Ke estimate.

LEI's CAPM Analysis:

Implementing the CAPM to determine Ke requires an estimate of the risk-free rate (RF), which is usually based on 30-year government bond yields, as is done by LEI and by myself as is discussed below. LEI's estimate of RF is 3.19% is based on forecast long-term Canada yields during 2025. As discussed above, as well as in greater detail in Section 3.7 and in Appendix A of my evidence, I disagree with the use of forecast yields versus using actual prevailing yields. I do note that 3.19% is very close to the actual 30-year government yield of 3.30% as of June 5, 2024 (which I use in my CAPM estimates), so the difference in this particular situation is minimal.

LEI proceeds to estimate an appropriate beta to use in the CAPM formula following the process it outlines on pages 117-119 of its evidence as summarized in Figure 40 on page 119. LEI ultimately decided to use the weighted average of the 5-year relevered raw beta estimates for each of the three proxy groups it used, and I agree with LEI's use of raw beta estimates as opposed to adjusted beta estimates (as discussed in Appendix C). LEI obtained its beta estimates by finding the average beta estimates for individual utilities included in three proxy sample groups (which differ from the groups used in its DCF analysis) – Generation (10 utilities – 7 U.S. based); Electric T&D (9 utilities – 8 U.S. based); and Gas Distribution (9 utilities – 7 U.S. based). Therefore, for the purpose of estimating beta, LEI examines a total of 28 utilities, 22 of which are U.S. based, as well as 6 Canadian utilities including Enbridge Inc. and Brookfield Renewable Corporation, which are questionable Canadian comparators. As argued above, I do not believe that U.S. utilities are reasonable comparators for Canadian utilities because they have significantly higher business risk (as discussed above and in Appendix

B), which is reflected in higher betas than for their Canadian counterparts (as discussed in Appendix C). As a result, LEI's final estimate of 0.69 is flawed by its heavy reliance on data for U.S. utilities, as well as the inclusion of some questionable Canadian utilities in its samples. LEI's approach also does not consider the relevance of historical beta estimates, which is an important consideration since beta "estimates" can vary through time.

LEI discusses its estimation of the market risk premium (MRP) it uses in its CAPM estimates on pages 119-122 of its evidence, where MRP = Expected Return on the Market (ERm) – RF, as discussed in Section 5.2 of my evidence. As noted in the MRP equation above, the MRP is actually the "expected" MRP as it is based on the existing RF and "expected" future market returns or ERm (over the long-term).

While making reference to historical data provides useful information in forecasting expected future market returns, it is not appropriate to ignore current market conditions and expectations, and simply assume the past (especially over relatively short time periods using predominantly U.S. data as is employed by LEI) will repeat itself. These issues are particularly important since five of the six potential MRP estimates considered by LEI are based on recent U.S. data over relatively short time periods. This is further complicated by the fact that LEI's three "preferred" MRP estimates[9] of 7.28% (S&P 1994-2023), 7.52% (S&P 2004-2023) and 10.16% (S&P 2014-2023) include overlapping periods of recent U.S. data. This effectively "triple weights" the most recent 2014-23 period, which is included in all three intervals and has an extremely high MRP estimate of 10.16% (which implies an **unrealistic estimate of ERm of 13.35%**, based on LEI's RF estimate of 3.19%). Similarly, using an average of the three MRP estimates of 8.32% corresponds to an ERm of 11.51%, which is also unrealistically high.

While I do not focus on U.S. evidence in applying the CAPM, it is noteworthy that the average expected market return for U.S. stocks based on surveys of finance professionals managing trillions of dollars that is provided in Section 5.2 (Table 7) of my evidence is 6.84% - well below the historical actual average return earned over the last few decades (including the historical periods examined by LEI). This is important to recognize, as it indicates that expected market return (and related expected MRP) forecasts that rely heavily on recent U.S. stock returns (such as that done by LEI), will be overly optimistic.

[9] LEI disregards the lone Canadian-based MRP estimate of 2.81%, which I agree is low, but would offset to some extent the unrealistically high estimates of 7.28%, 7.52% and 10.26% that it uses.

In fact, it is well-known that the U.S. stock market has experienced exceptional returns over the past few decades, producing abnormally high real returns relative to its longer term history, and relative to global equity returns in other markets. I have attached an article as Attachment AD, which expands on this matter. The authors note that: "The real return on U.S. stocks from 1950 through 2023 was 7.63 per cent, and 7.16 per cent for the 20 years ending December 31, 2023. A real return above 7 per cent is exceptional even for the U.S. market. From 1900 through 1950, U.S. stock returned a real annualized 5.57 per cent." They further note that "Global real stock returns from 1900 through 2023 were 5.16 per cent annualized" (based on analysis of 38 developed markets). Putting this in perspective, they note that: "The often cited 10-per-cent return for stocks based on the post-1950 period is roughly equivalent to a 7-per-cent real return in the historical data. That is about 2 per cent higher than unbiased estimates of U.S. expected returns, U.S. equity returns before 1950 and global stock returns spanning 1890 through 2023." Similar to the U.S. stock returns forecast by investment professionals reported in Table 7 of my evidence, the authors expect future real returns for U.S. stocks in the 4.25% range, and combine this with 2.5% expected inflation to arrive at an expected U.S. stock market return of 7.24%, much more in line with the forecasts provided in Table 7.

I believe that both historical returns and current expectations of market professionals represent the <u>best</u> sources of information regarding future long-term market returns. My analysis in Section 5.2 considers both historical results and market forecasts for Canada that are presented in Table 7, as well as 2024 forecasts for MRPs (Canada – 5.2%; U.S. – 5.5%) that are generally consistent with the U.S. estimates provided by Kroll, which LEI notes in its evidence has ranged between 5 and 6% since 2008, and was estimated at 5.5% in 2023. However, LEI chose not to consider the Kroll estimates and further it does not examine current investor expectations regarding future market returns in the U.S. (or Canada). Instead LEI relies on its three "preferred" MRP estimates of 7.28%, 7.52% and 10.16% based on recent U.S. historical evidence, and produces related Ke estimates of 8.23%, 8.39% and 10.22% respectively. LEI then takes the average of these three estimates of 8.95%, which it uses as its CAPM estimate of Ke, and uses as its recommended base ROE recommendation.

LEI's final CAPM estimate of 8.95% is **upwardly biased** for several reasons. First, the use of a beta estimate (0.69) that is based solely on current beta estimates (without due consideration of historical beta estimates), is unreliable as beta estimates vary through time. Further, the current estimates are based on samples that include 22 of 28 U.S. utilities, which are riskier than Canadian utilities (as demonstrated in in Appendix B of my evidence), and have historically had higher beta estimates (as demonstrated in in Appendix C of my evidence). Finally, LEI's MRP estimates do not consider current market conditions or investor expectations regarding future market returns (or MRPs) in the U.S. (or Canada), but simply focuses on U.S. historical evidence during relatively short time periods that reflect above average historical MRPs, and which triple weights the most recent period, thus providing a totally inflated and unrealistic MRP estimate that implies expected future long-term stock returns of 11.5%. These estimates are inconsistent with the practice employed by investment professionals (as reflected in the Kroll MRP estimates since 2008 of between 5 and 6%), and of using an MRP within the 4-6% range (which is the norm) in the CAPM, as discussed in Section 5.2 of my evidence.

<u>Transaction Costs and the Cost of Equity:</u>

LEI states on page 122 of its evidence that:

> As with LEI's recommendation for the treatment of transaction costs from debt issuances, LEI recommends considering the transaction costs associated with equity issuances as operating costs for similar reasons. Equity issuances do not happen with predictable regularity, which makes it more suitable to recover such costs as and when the utility incurs expenses.

Similar to my response regarding debt financing transaction costs provided in Section 3.8, I believe the current practice of adding 0.5% to Ke estimates seems reasonable, since it embeds the actual costs of equity financing related to new equity issues into the cost of equity, as they should be. The fact that most companies (utilities and other businesses alike) do not frequently engage in new equity issues does not detract from the fact that such issuing costs have a legitimate impact on their actual long-term equity financing costs when they do occur. As such, I believe the OEB's current practice of adding 0.5% to Ke estimates is a reasonable compromise, contrary to LEI's suggestion that these costs be included in operating costs.

<u>My Base ROE Analysis and Recommendations:</u>

<u>Context:</u>

I would note that my base ROE analysis is built upon my analysis of current and expected macroeconomic and capital market conditions that is presented in Section 4 of my evidence.

The details of my estimate of the appropriate base ROE are presented in Section 5 of my evidence and are based on estimating the **current market determined required return on equity for Ontario utilities**, or Ke.

My analysis in Section 5 begins by providing evidence in Section 5.1 which shows that the allowed ROEs in Canada have not declined in line with reductions in government and utility bond yields, and hence are providing Ontario (and other Canadian and U.S.) utilities "excess compensation" in terms of allowed ROEs relative to their actual market-determined cost of equity. Section 5.1 also shows that the downward "stickiness" in awarded ROEs noted above is not unique to Ontario but can be observed in other Canadian jurisdictions, and is even more prevalent in the U.S., which is evidenced in the results of a 2017 study that examines "a dozen years' of gas and electric rate-setting decisions" in the U.S. and Canada over the 2005-2016 period.[10] A recent study by Sikes (2022) entitled "Regulatory Inequity" similarly shows that the average awarded ROE is much greater than the average utility's cost of equity, which means that any investments undertaken by the utilities creates value (i.e., generates economic rent).[11]

During testimony at the EB-2022-0200 OEB Proceedings, I noted that allowed ROEs have not declined adequately in response to the reduction in the cost of capital that utilities' have experienced, as long-term government bond yields (or RF) and A-rated utility bond yields have declined significantly over the last two decades. Section 5.1 of my evidence shows that since 2004, both RF and A-rated utility yields have declined markedly, while the allowed ROEs have declined much less so over this period. As a result, the spreads between allowed ROEs and these yields, both of which directly affect the utilities' cost of capital, have **increased** dramatically though the years. For example, in January 2004, the allowed ROE by the OEB was 9.88%, at a time when 30-year government yields (RF) were 5.3% and A-rated utility yields were 6.1%. So, the spread between the allowed ROE and RF was **4.57%**, and between ROE and A yields was **3.78%**. However, as of June 5, 2024, the allowed ROE was **0.67% lower** than in 2004 at 9.21%, while RF was **2.0% lower** at 3.30%, and A yields were **1.42%**

[10] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2994314). Appended to this evidence as Attachment AE.

[11] Source: Sikes, Thomas, M. S. January 2022, "Regulated Inequity – How regulators' acceptance of flawed financial analysis inflates the profit of public utility companies in the United States". Appended to this evidence as Attachment AF.

lower at 4.68%. As a result the ROE-RF spread was 1.34% higher than in 2004 at **5.91%** (a 29% increase), while the ROE-A yield spread was 0.75% higher at **4.53%** (a 20% increase). The average ROE-RF spread during the January 2004-June 2024 period was 6.03%[12] and the average ROE-A-yield spread was 4.61%.[13] Unfortunately, the fact that allowed ROEs have not decreased in North American jurisdictions (including Ontario) proportionately to changing capital market conditions and the associated reduction in the costs of capital to utilities has resulted in awarded ROEs that have been well in excess of the utilities' cost of equity, with the costs being borne by consumers, as noted in the two studies cited above.

The existence of currently inflated ROEs in Canada and the U.S. is reflected in the evidence I provide in Section 5.5, which shows that the average "market-determined" price to book (P/B) ratio for Canadian publicly traded utilities averaged 1.65 over the 2017-2023 period, with the 2023 average sitting at 1.45. Generally speaking, higher P/B ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning (and expected to earn) rates of return that are at least "fair," if not above fair (i.e., ROE > Ke, since technically P/B should equal 1 if ROE = Ke, and **if they exceed one it indicates they are earning excess economic rent**). Recognizing that four of the five Canadian utilities included in that sample are holding companies that operate in several jurisdictions that are riskier than Ontario (and Canada in general), and that also hold significant proportions of unregulated assets, it is interesting to note that the sole publicly-listed regulated operating Canadian utility (Hydro One) had a P/B ratio of 2.04 as of the end of 2023. It is further interesting to note that the average P/B ratio for the U.S. sample was greater than the Canadian average every year, ranging from 1.69 to 2.36 and averaging 2.05 over the 2017-2023 period. This is consistent with evidence provided in Section 5.1 of my evidence discussed above that shows that allowed ROEs in the U.S. are even more upward biased than those in Canada.

[12] This is equivalent to using the CAPM and using a market risk premium (MRP) estimate of 6%, which is at the high end of traditionally employed estimates, and simultaneously using a beta for Ontario utilities of 1.0 (which is more than double the long-term average beta for Canadian utilities of about 0.35). Or alternatively this 6% figure could result if we used a beta of 0.5 for utilities, but then used an MRP of 12% - which far exceeds any estimates ever used for this variable.

[13] This is equivalent to using the bond yield plus risk premium approach (which I discuss below) to estimate the cost of equity, and using a risk premium estimate of 4.6%. This number is close to the maximum range of traditional estimates used (i.e., in the 2.0-5.0% range) – and would apply to high risk companies, and clearly not to regulated Canadian operating utilities, which will be well below average risk – so something less than 3.5% should be used – and I use 2.5%.

CAPM Estimates:

Section 5.2 of my evidence provides a detailed breakdown of my CAPM estimates. These are based on using an RF = 3.30% as discussed in Section 5.2.2 of my evidence, which was the actual 30-year Canada yield as of June 5, 2024. As discussed in detail in Section 5.2.3, my estimate of MRP is 5%, which is the mid-point of the commonly used 4-6% range, which is based on the observation that capital markets currently reflect fairly normal conditions.

My MRP estimate of 5% equals the 4.97% average difference between Canadian stock and government bond returns over the 1938-2023 period, is 1.7% above the long-term geometric mean MRP of 3.3% estimated by Dimson et al., and is slightly above the mid-point of 4.7% of the long-term arithmetic average Canadian MRP of 4.2% and the 5.2% average forecast MRP documented by Fernandez et. al (2024)'s survey of finance professionals. It is also consistent with the well-established practice among finance professionals of using an MRP estimate of 6% when market uncertainty is well above average, using 5% when markets are close to normal, and using 4% during periods of extreme market and economic optimism. I would note that this estimate appears on the high side relative to the Canadian expected market returns provided in Table 7 of my evidence (since combined with my RF estimate it implies an ERm of 8.3%), which range from 4.1% to 7.2%, and average 6.1% for the next 10-20 years. However, it is in line with forecast future MRPs of 5.2%, and with historical evidence suggesting an ERm estimate in the 7.6-9.3% range.

The determination of my beta estimate for the CAPM is described in detail in Section 5.2.5 of my evidence, following the approach described below that is based on the evidence and discussion provided in Appendix C:

1. Ensure beta estimates are from reasonable comparators – i.e., **exclude U.S. utility beta estimates**.
2. **Do not use traditional "adjusted beta" estimates,** which are based on the inaccurate assumption that utility betas gravitate towards one in the long run.[14] If there is a desire or need for a "mechanical approach" to adjusting current beta estimates, simply adjust them toward the long-term average of 0.35, or even 0.45, rather than toward 1.0, as is done with published betas provided by services such as Bloomberg and Value Line.

[14] This is consistent with the approach used by LEI in its evidence, with final beta estimates determined based on raw beta estimates.

3. Based on historical evidence, establish a range of reasonable beta estimates with a lower bound of 0.30 and an upper bound of 0.60.
4. After collecting and considering as much evidence as possible, and given the constraints (i.e., permissible range) discussed in #3 above, make a simple judgment based on current beta estimates.

Based on the application of this approach, I do not consider U.S. beta estimates, since I believe U.S. utilities are too risky to be legitimate comparators. Based on current Canadian utility beta estimates provided in Table 8 that provide an average estimate of 0.60 (which is much higher than a similar average estimate in 2023 of 0.355 and which is well above the long-term average), and combining this with the long-term historical average Canadian utility beta estimate of 0.35, it is appropriate to continue to assume that a reasonable estimate of beta for a typical Ontario utility should lie within the 0.30 to 0.60 range noted above. I remain consistent with my previous recommendations in the 2013, 2016, 2018, 2021 and 2023 Alberta GCOC Proceedings, and use the mid-point figure of my recommended range (i.e., 0.30-0.60) of **0.45** as my best point estimate, which is above the mid-point of the long-term average of around 0.35, and is below the current average beta estimate of 0.60.

While government bond yields have risen over the last few years, they still remain relatively low, both in absolute terms and by historical standards. A-rated Canadian utility bond yield spreads were sitting at 138 bp as of June 5, 2024, virtually identical to the long-term average spread of 140 bp (which further indicates normal capital market conditions). Consistent with my previous evidence, I adjust for any differences in this average yield spread based on research provided by analysts at the Bank of Canada that indicated that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian utilities.[15] Based on this this research, I have always subtracted half of the “above or below average” yield spread (i.e., (0.138 - 0.140)/2), or -0.001% today (which is negligible), to my CAPM estimate to account for this time varying risk premium.

Finally, I add 50 bp for financial flexibility (or flotation costs), consistent with previous OEB practice. Combining these items, I provide my CAPM estimates for the required equity return

[15] Refer to: A. Garcia and J. Yang, “Understanding Corporate Bond Spreads Using Credit Default Swaps,” Bank of Canada Review, Autumn 2009. This article is appended as Attachment AG to this evidence.

for the typical regulated Ontario utility, which are reported in Section 5.2.5 in Table 9 of my evidence, which I replicate below. Based on these calculations my CAPM analysis suggests an ROE of **6.05%**.

Estimate	**RF (%)**	**MRP (%)**	**Beta**	**Spread Adjust. (%)**	**Financial Flex. (%)**	**Ke (%)**
CAPM Best Estimate	3.30	5.0	0.45	-0.001	0.50	**6.05%**

As mentioned above, the CAPM parameters used (i.e., RF of 3.30%, MRP of 5% and a negligible spread adjustment of -0.001%) imply a required return on the entire market of 8.3%, well above the long-term market return expectations of finance professionals of 6.1% provided in Table 8 of my evidence, while it is in line with the long-term real returns on Canadian stocks. It is also marginally above my best estimate of 7.5% for the long-term expected return on the market that I discuss later in my evidence.

DCF Estimates:

I obtain my final DCF approach Ke estimate based on application of the single-stage Dividend Discount Model (DDM) and a multi-stage version of the DDM called the H-Model, both of which are described in detail in Section 5.3 of my evidence. I rely solely on my Canadian utility sample for the reasons discussed above, but I do note that the results for my U.S. sample are virtually the same as those for the Canadian sample.

The Canadian sample Ke estimates obtained using the single-stage DDM lie in a range from 6.30% to 8.00%, and I use as my best estimate the average of four estimates, which is **6.91%** (before adding 0.5% flotation costs). This estimate is obtained using December 31, 2023 average and median dividend yields for the sample, as well as 7-year averages and medians, all of which range from 4.53% to 5.71%. It is also based on sustainable growth rate estimates ranging from 1.46% to 2.17%, and averaging 1.80%, which seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth in the 3.3-4.3% range as discussed previously.

My H-Model Ke estimate for the Canadian sample is 6.88% (before flotation costs), which is virtually identical to my single-stage DDM estimate of 6.91%. Weighting these two DDM estimates equally gives me a final DCF estimate of 6.9%, or **7.4%** after adding 0.5% for flotation costs. I would note that the 6.9% estimate is only 0.5% below my overall DCF estimate for the market of 7.4% (as estimated in Section 5.3.2 of my evidence), so it seems slightly high for well below-average risk utilities relative to overall expected market returns.

Bond Yield plus Risk Premium (BYPRP) Estimates:

My third and final approach that I use to estimate Ke is the BYPRP approach, which adds a risk premium (generally in the 2-5% range) to the yield on a firm's outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium (or MRP) used in the CAPM, which represents the premium above government risk-free yields and expected overall stock market returns. The BYPRP approach is depicted below:

Ke = Company's Bond Yield + Company Risk Premium

This approach is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts and by over 50 percent of Canadian CFOs.

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable ***market-determined*** bond yields (which include yield spreads that can be viewed as debt financing *risk premiums*), to estimate the required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these two required returns (i.e., the greater the company-specific risk premium).

The first step in applying the BYPRP approach is to obtain an estimate of the cost of long-term yields on a typical utility. As of June 5, 2024 the yield on long-term A-rated Canadian utility bonds was 4.68% according to the Bloomberg data provided in Figure 3 of my evidence. This figure is close to the average yield of 4.78% on bonds outstanding for five Canadian utilities as of June 6, 2024, as reported in Section 5.4 of my evidence. This evidence implies that 4.7% is a reasonable starting point for my BYPRP estimate.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of 2.5%.[16] Combining this information, I obtain the following estimate for Ke according to this approach:

Ke = 4.7 + 2.5 = 7.2%

If we add 50 bp for flotation costs, we end up with a Ke estimate **7.7%**. This is on the high side given my long-term expected market return estimate of 8% (if we add 0.50% to my raw market estimate of 7.5%). It is also well above my CAPM estimate of 6.1% and 30 bp above my DCF estimate of 7.4%.

Final Ke Estimate:

I weight all three of my Ke estimates equally, as I have done in all my previous evidence, because all three methods are used in practice and provide different perspectives on Ke. As discussed previously, CAPM is more heavily relied upon in practice due to its conceptual advantages. For example, previous studies (referenced in Section 5 of my evidence) indicate with respect to the DCF approaches to estimating Ke, they were used by:

- only 15% of U.S. CFOs - versus over 70% for CAPM;
- about 12% of Canadian CFOs - versus close to 40% for CAPM.
- Not widely used, while CAPM was used by the majority of investors.

CAPM is also very intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are data uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, since most of them are not publicly listed. The BYPRP approach is much more widely used than DCF approaches due to its intuitive nature, and because it adjusts for market-determined borrowing rates and risk. In fact the BYPRP approach is more widely used than CAPM by Canadian CFOs, as mentioned above. Thus the BYPRP approach accounts for interactions between market-determined company debt costs and equity markets, and as such it is intuitively sound.

[16] For example, Attachment AH provides an example of implementing the BYPRP approach for IBM from the CFA curriculum, where a risk premium of 2.75% is added to cost of IBM's debt. Clearly IBM (at that time) is riskier than an Ontario regulated A-rated operating utility, so 2.5% is very reasonable by comparison.

Based on an equal weighting of the three approaches, I determine the following best estimate for allowed Ontario utility ROEs:

Ke = (1/3)(6.05) + (1/3)(7.4) + (1/3)(7.7) = **7.05%**

This estimate is very reasonable when compared to expected long-term overall stock market returns in the 4-9% range and a long-term expected market return of 7.5% (without any flotation charges added), when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three decades and double digit "nominal" returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 4-9% range are consistent with current long-term forecasts by market professionals (which averaged 6.1%) and with historical long-term real stock returns.

While I do not use the estimates of Ke based on my examination of P/B ratios in Section 5.5 of my evidence, it is worthy to note that using the average P/B ratios for Canadian utilities and allowed or actual earned ROEs would imply Ke figures ranging from 5.91% to 6.81% (before adding 0.5% in flotation costs), while U.S. estimates would range from 6.45% to 6.50%. Both the Canadian and U.S. implied Ke estimates above are very much in line with my final ROE estimate for Ontario utilities of 6.55% before adding 0.5% for flotation costs. While I do not assign any weight to the P/B analysis for purposes of determining Ke, the bottom line of this analysis is that the P/B ratios for utilities reported above indicate that Ontario (and other Canadian) utilities appear to be earning a more than satisfactory ROE, and have done so for quite some time. This is important **market-based** information that supports my Ke estimates, and confirms that Canadian (and U.S.) utilities currently earn ROEs well in excess of their required equity return.

3.10.2 LCBF

As discussed in my response to Issue #7, currently the OEB estimates LCBF based on Canada 10-year yield Consensus forecasts, and estimates a spread that it adds to estimate corresponding 30-year Canada yields. LEI recommends relying on published forecasts of Canada 30-year yields, which has the benefit of not having to estimate the spread between 10- and 30-year Canada yields, which varies through time and is difficult to forecast.

While the LEI recommendation is an improvement, Appendix A demonstrates, using Canadian data over the 2011-2023 period, that using existing 30-year yields produces **statistically**

significantly more accurate forecasts of actual 30-year yields in the subsequent period than using forecasts (as discussed in greater detail in response to Issue #7). The evidence in Appendix A shows an **upward bias** in forecasts of **about 0.4%**, which is substantial. In contrast, the average forecast yields using the previous actual yields at the start of the period would have been unbiased on average.

Based on this evidence, I recommend that rather than using forecasts for LCBF, the Board should use the actual prevailing bond yields, and I further recommend using the actual prevailing rate as of September 30, 2024, which should be a better estimate of future rates than using an average for the month of September, as discussed in my response to Issue #7. This approach also has the added benefit that it is easier to implement, since it does not require obtaining yield forecasts, estimating the spread between 10- and 30-year Canada yields, or even obtaining bond yield data for an entire month. As mentioned previously, estimating the spread between 10- and 30-year Canada yields is not a trivial matter and is fraught with uncertainty. For example, while this spread averaged +0.38% over the 2004-2023 period, it has been as low as -0.23% and as high as +0.81%, and sat at -0.09% on June 5, 2024.

3.10.3 UtilBondSpread

The OEB currently estimates UtilBondSpread as the average spread between A-rated utility yields and 30-year Canada yields during the September previous to the test year. LEI supports maintaining this approach, but suggests using a 12-month trailing average, instead of a one-month average.

I agree that this variable should continue to be included in the ROE formula; however, I recommend that this spread would be best determined using the actual spread as of September 30th, rather than using an average for the month (or for the previous 12 months). It is always preferable to use the most timely estimate of current capital market conditions as is feasible since this spread, like most capital market factors, can change through time. For example, while the average spread over the 2003-2024 period was 1.40% (as shown in Figure 3 of my evidence), it fluctuated from 0.76% to 3.05% over the period, and sat at 1.38% as of June 5, 2024. In particular, something(s) could have happened during the most recent month (or months) that could either ease (or elevate) bond investors' risk assessments, which would be reflected in lower (or higher) yield spreads, and hence spreads existing before this unexpected event (or events) would not be as representative as the prevailing spreads at the end of the month, **which reflect the most recent capital market conditions**. This approach also has the added benefit that it is easier to implement, since it would not require obtaining utility and government bond yield data for an entire month.

3.10.4 LCBF and UtilBondSpread Adjustment Factors

Currently the OEB uses an adjustment factor of 0.5 for both the LCBF and UtilBondSpread variables in its ROE equation. LEI recommends changing these adjustment factors to 0.26 for LCBF and to 0.13 for UtilBondSpread. LEI bases its recommendation on the results of a multivariate regression that it describes on page 116 of its evidence as using "the weighted average ROEs allowed by US regulators for electric and gas utilities as the dependent variable; 30-year GoC government bond yields and Moody's seasoned Baa corporate bond yields as independent variables." However, Appendix B of LEI's evidence indicates that U.S. 30-year Treasury yields were used in the regression, and not 30-year GoC yields – so it is not clear to me which variable was actually used.

Regardless of whether LEI's regression specification includes long-term Canada or U.S. government bond yields in the regression, the results of this regression are not relevant with respect to current capital market conditions in Canada that are intended to be reflected in the OEB's ROE formula, as captured by changes in LCBF and UtilBondSpread, and therefore should not be considered.

The regression specification is flawed by design since allowed ROEs in U.S. jurisdictions do not have a direct relationship with changes in capital market conditions in Canada. These allowed ROEs do not change frequently (only during ROE reviews or annually at best if the jurisdiction uses a formula), **unlike the LCBF and UtilBondSpread factors which change daily**. Further, allowed ROEs for U.S. utilities have no direct relationship to Canada government yields (which often differ from U.S. yields as they do today) or with Canadian yield spreads. U.S. allowed ROEs are more likely to be affected by changes in U.S. yields and U.S. yield spreads – although even this relationship is difficult to estimate (since they do not necessarily accurately reflect the actual required return on U.S. utilities' cost of equity (Ke) as discussed in Section 5.1 of my evidence). As the AUC stated in Alberta 2018 GCOC Decision 22570-D01-2018, para. 393 (emphases added): "In the Commission's view, although observable, the **ROEs approved for the U.S. utilities are not strictly market data**."

I would further note that by definition, the risk-free rate or RF (which is proxied by LCBF in the OEB ROE formula) should have a correlation of zero with market returns (and thereby provide zero explanatory power as an independent variable in a regression where market returns are the dependent variable) according to the CAPM, since it is defined as a risk-free investment. The data included in Attachment A was used to produce Table 6 of my evidence, which reports summary statistics for Canadian capital markets over the 1938 to 2023 period. Based on these 85 years of Canadian capital market observations, the correlation coefficient between Canadian stock returns and long Canada bond yields (i.e., RF) was +0.01 – very close to the CAPM predicted correlation of 0. Hence, it seems that any regression designed to predict the exact adjustment factors to be used for LCBF, and for UtilBond Spread, will not provide meaningful results. Therefore, I disagree with LEI's recommended adjustment factors – the existing adjustment factors of 0.5 would be preferable.

While I would choose the existing adjustment factors of 0.5 in preference to those recommended by LEI, as discussed above in Section 3.10.1, the evidence I provide in Section 5.1 shows that allowed ROEs in Ontario (and other jurisdictions) have simply not declined adequately in response to the reduction in the cost of capital that utilities' have experienced, as long-term government bond yields (or RF) and A-rated utility bond yields have declined significantly over the last two decades. As a result, the spreads between allowed ROEs and these two measures, both of which directly affect the utilities' cost of capital, have *increased* dramatically though the years.

In particular, Section 5.1 shows that in January 2004, the spreads between the allowed ROE and RF was **4.57%**, and between ROE and A yields was **3.78%**. But as of June 5, 2024, the allowed ROE-RF spread was 1.34% higher than in 2004 at **5.91%** (a 29% increase), while the ROE-A yield spread was 0.75% higher at **4.53%** (a 20% increase). The average ROE-RF spread during the January 2004-June 2024 period was 6.03% and the average ROE-A-yield spread was 4.61%.

For illustrative purposes, as the OEB reconsiders its existing ROE formula, Figure 9 in Section 5.1 of my evidence also includes the OEB allowed ROEs that would have resulted if the OEB had used an adjustment factor of 0.75 instead of 0.5 for both terms in their ROE formula since the formula's implementation being reflected in 2010 and subsequent allowed ROEs. The graph shows that increasing the adjustment factors makes allowed ROEs more responsive to changing market conditions than using 50% adjustment factors, but not significantly more volatile. This is reflected in lower resulting June 5, 2024 Allowed ROE to RF and A-yield spreads of 5.64% and 4.26% respectively for this approach, which are about 30bp lower than the actual spreads. Similarly, the averages for the RF and A-yield to allowed ROE spreads over the period, which were 5.80% and 4.39% respectively, about 20bp below the actual average spreads over this period. Based on this evidence, I recommend an adjustment factor of 0.75 for both factors, which maintains the relationship, is more responsive to changing market conditions, and will still reduce year-to-year fluctuations in allowed ROEs relative to a weighting of 1.0.

3.10.5 Summary of Recommendations

My final recommendations with respect to Issue #10 can be summarized as:

10) Maintain the existing ERP formula methodology, but make the following modifications:

1. Update the base ROE to 7.05%.
2. Update the base LCBF factor to the September 30, 2024 actual yield on 30-year Canada bonds (I use the current yield of 3.30% as a placeholder in the revised equation below).
3. Update the base UtilBondSpread value to the actual September 30, 2024 value (I use the current spread of 1.38% as a placeholder in the revised equation below).
4. LCBF should be estimated as the actual yield on 30-year Canada bonds as of September 30th in the year preceding the test year.
5. UtilBondSpread should be estimated as the actual spread on A-rated utility bond yields as of September 30th in the year preceding the test year.
6. Change the existing adjustment factors for LCBF and UtilBondSpread from 0.5 to 0.75.

These recommendations result in the modified version of the current OEB formula presented below (with 3.30% and 1.38% serving as placeholders for the base LCBF and UtilBond Spread variables):

$$\boldsymbol{ROE_t = 7.05\% + 0.75 \times (LCBF_t - 3.30\%) + 0.75 \times (UtilBondSpread_t - 1.38\%)}$$

3.11 Return on equity – relevance and consideration of debt and equity investor perspectives

***Issue 11: Are the perspectives of debt and equity investors in the utility sector relevant** to the setting of cost of capital parameters and capital structure? If yes, **what are the perspectives relevant to that consideration**, and **how should those perspectives be taken into account** for setting cost of capital parameters and capital structure?*

As LEI notes on pages 127-128 of its evidence (bold added for emphasis, footnotes omitted):

> OEB's existing cost of capital methodologies **explicitly consider equity and debt investor perspectives**. **The allowed ROEs are legally required to meet the FRS**. **The FRS inherently requires sufficient returns for the commensurate risk undertaken by the investors and ensure that the utilities continue to attract incremental capital at reasonable terms**. The DLTDR and DSTDR formulas are formulated considering OEB-regulated entities' credit profiles (as set by the credit rating agencies).
>
> OEB is also **among the few North American regulators to annually update the cost of capital parameters** to ensure they align with the current macroeconomic environment. As such, **LEI is not aware of OEB-regulated entities facing notable issues in attracting equity and debt capital since 2009**. This is **also reflected in the utility credit ratings and the regulator assessments performed by the credit rating agencies**. For instance, S&P Global assesses the US and Canadian regulatory regimes based on analysis of quantitative and qualitative factors such as regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation.
>
> Based on its assessment, S&P groups US states and Canadian provinces into 5 categories: (i) credit supportive; (ii) more credit supportive; (iii) very credit supportive; (iv) highly credit supportive; and (v) most credit supportive.
>
> In its November 2023 assessment, **S&P classified the Province of Ontario and two other Canadian provinces as 'most credit supportive'**, as can be seen in the following figure.

LEI further notes on page 129 of its evidence (bold added for emphasis, footnote omitted) that:

> **DBRS considers the regulatory regime in Ontario to be one of the key strengths** in its rating considerations. For instance, in its recent November 2023 credit rating for Hydro One, it stated that the OEB's regulatory regime permits Hydro One ***a reasonable opportunity to recover operating and capital costs****, and to earn the approved return on equity (ROE).* Further, it *views the utility regulatory framework in Ontario as* ***transparent and supportive*** *for regulated transmission and distribution operators*.

I am in full agreement with LEI's assessment above. LEI also notes in its summary on page 16 of its evidence that: "The DLTDR and DTDSR formulae are devised considering OEB-regulated entities' credit profiles." I also agree with this statement, as discussed in my responses to Issues #4-7.

I would note that the approach of determining an appropriate estimate of the required ROE and appropriate estimates of DLTDR and DTSDR **implicitly** considers the perspectives of both debt and equity investors. Determining an allowable ROE that satisfies the FRS in effect should ensure this is the case. For example, my BYPRP Ke estimate for ROE is based on providing a return to equity investors that is above the required return on a utilities' cost of long-term debt. As such, it concurrently considers the perspectives of both debt and equity investors, which are inextricably linked as they operate in the same universe; albeit with slightly different perspectives. In particular, debt investors are totally focused on receiving their promised interest payments, since the only way they receive capital gains is if interest rates decline – and so safety of income returns is their number one priority. While safety of returns is also important to equity investors, they are more inclined to also focus more on the upside of their equity investments, which can vary significantly depending on the investment.

My recommendation, which is consistent with that of LEI, is:

> 11) The current OEB approach takes into account the perspectives of both equity and debt investors and comfortably satisfies the FRS.

3.12 Capital structure – setting capital structure in accordance with the FRS

Issue 12: How should the capital structure be set *for electricity transmitters, electricity distributors, natural gas utilities, and OPG* ***to reflect the FRS****?*

LEI notes on page 134 of its evidence (bold added for emphasis, footnote omitted) that:

> The OEB's policy/guidelines *assume that the base capital structure will remain relatively constant over time* and require undertaking a full reassessment of a utility's capital structure **only in the event of significant changes in the company's business and/or financial risk**.
>
> As such, the OEB sets a uniform ROE for all regulated entities, and it increases the equity thickness in the capital structure if it assesses that an entity's business and financial risks have increased relative to the previous assessment. On the other hand, the allowed equity thickness can be reduced if OEB assesses that the business and financial risks for a regulated utility has decreased significantly.

LEI further notes on page 135 of its evidence that (bold added for emphasis):

> The **key business and financial risks considered by the OEB in recent equity thickness proceedings** are discussed earlier in Section 4.2. **Meeting the FRS is a key consideration in these proceedings**. For instance, if the OEB concludes that the risk profile of a utility has increased, it increases the allowed equity thickness commensurate with increased risk.

As noted in my response to Issue #2 in Section 3.2, I believe the OEB's current approach to reviewing business and financial risk factors adequately addresses the assessment of appropriate risk factors and changes therein. I concur with LEI's position that the OEB's current practice of setting a uniform ROE and adjusting the capital thickness if it determines upon application that there has been a meaningful change in business/financial risks is appropriate, which is consistent with current practice in many other jurisdictions.

Finally, I also agree with LEI's recommendation that applicants should be required to include forward cash flow modeling and scenario analysis showing impact on credit metrics to support their case on capital thickness in a rebasing application, which seems pragmatic, as it can guide the OEB as to whether or not applications to adjust capital thickness are worth pursuing, while recognizing that such analysis would in any case normally be part of the evidence provided during any rebasing application that occurs.

My recommendation, which is consistent with that of LEI is:

> 12) - I concur with LEI's position that the OEB's current practice of setting a uniform ROE and adjusting the capital thickness if it determines upon application that there has been a meaningful change in business/financial risks is appropriate.

- I also agree with LEI's recommendation that applicants should be required to include forward cash flow modeling and scenario analysis showing impact on credit metrics to support their case for adjustment of capital thickness.

3.13 Capital structure – appropriate capital structure for single vs. multiple-asset transmitters

Issue 13: *Should the OEB take a* ***different approach for setting the capital structure*** *for electricity transmitters depending on whether they are a* ***single versus multiple asset transmitter****?*

The OEB currently allows the capital structure for transmitters to be determined on a case by case basis, while it has maintained an allowed equity ratio of 40% for all electricity transmitters (and electricity distributors) since 2006.

On page 143 of its evidence LEI notes that:

> The reasoning provided by the OEB in 2006 to move away from the size-based capital structure determination (described in Section 4.12.4) for electricity distributors also applies to electricity transmitters. The risk profile of electricity transmitters is similar to, if not lower than, that of electricity distributors. As such, it is reasonable to consider the same approach to setting capital structures as electricity distributors.

Given the importance of Hydro One Inc. to Ontario's electricity sector, accounting for well over 90% of transmission and over one third of all distribution (e.g., 35.6% as of 2020), I have examined in detail Hydro One's equity thickness.

My recommendation is:

> 13) the OEB should **reduce Hydro One's allowed equity ratio to 38%**, and should consider reducing it further to 36% over the following 2-3 years.

3.14 Mechanics of implementation – monitoring mechanism to test the reasonableness of the cost of capital methodology

Issue 14: What on-going monitoring indicators to test the reasonableness of the results generated by its cost of capital methodology should the OEB consider, including the monitoring of market conditions?

The OEB currently engages in a regular monitoring process that includes reviewing internal quarterly reports that it has prepared for internal review purposes. These reports involve: 1. an updating of the ROE formula inputs and estimation of the implied ROE, which can be compared to the actual allowed ROE determined for the test year; and, 2. a broader assessment of the current macroeconomic environment, including reference to recent developments.

This practice allows the OEB to examine the reasonableness of existing cost of capital parameters in response to changing macroeconomic and capital market conditions. It also exceeds the monitoring done in all but one of the jurisdictions surveyed by LEI, which is consistent with my expectations. As such, I believe this practice adds value and should be retained.

My recommendation, which is consistent with that of LEI, is:

14) The OEB's current practice of continuous monitoring through the review of quarterly reports adds value and should be retained.

3.15 Mechanics of implementation – review mechanism to ensure adherence to FRS

Issue 15: How should the OEB regularly confirm that the FRS continues to be met and that rate-regulated entities are financially viable and have the opportunity to earn a fair, but not excessive, return?

The OEB's current annual review process confirms whether "the FRS continues to be met," as reported in its annual cost of capital update letters. The current approach as described by the OEB should be retained as it satisfies the FRS, and it is further complemented by the quarterly review process discussed with respect to Issue #15 above. LEI agrees with this conclusion, and further proposes some pragmatic additional annual reporting requirements that should contribute to the accuracy and transparency of the reviews, which should not add excessive administrative burden for the utilities. As noted on page 151 of LEI's evidence, these recommendations include: "to provide credit ratings and details regarding new short-term and long-term debt and equity issued/borrowed during the year."

My recommendation, which is consistent with that of LEI, is:

15) - The OEB retain its current annual review practice.

- The current annual review process can be supplemented by adding annual reporting requirements for utilities to provide credit ratings, as well as details regarding new short-term and long-term debt and equity issued/borrowed during the year.

3.16 Mechanics of implementation – the timing of the OEB's annual cost of capital parameters updates

Issue 16: What should be the timing of the OEB's annual cost of capital parameters updates, including the timing, as required, of the underlying calculations?

As noted by LEI on page 151 of its evidence: "The OEB updates the cost of capital parameters every year and publishes a letter with the updated parameters in October or November for rates taking effect in January of the following year. The underlying calculations typically rely on data as of the end of September."

LEI recommends the timing of this process be retained, which I am comfortable with. However, I do believe that the use of October data as opposed to September data, would provide more up-to-date capital market estimates and hence improve the accuracy of the parameters used in the ROE formula (as discussed in response to Issues 7 and 10), which is consistent with the approach recently introduced in Alberta. I do recognize that Alberta was reintroducing an ROE formula approach so it was easier for the AUC to adapt the October estimation period than it would be for the OEB, which has followed the same process for several years. As LEI points out on page 152 of its evidence: "Stakeholders are familiar with the OEB's existing cost of capital update schedule, and so continuing this approach would promote predictability and stability objectives." Therefore, I recommend the OEB maintain the status quo, but that there would be benefits to changing to the use of October data rather than September data to update the ROE formula, if the OEB determined this change would not cause undue disruptions to its existing processes and procedures.

My recommendation is:

16) Maintain the status quo, but consider changing to the use of October data rather than September data to update the ROE formula, if the OEB determined this change would not cause undue disruptions to its existing processes and procedures.

3.17 Mechanics of implementation – monitoring mechanism to test the reasonableness of the cost of capital methodology

Issue 17: What should be the defined interval (for example, every three to five years) to review the cost of capital policy (including, but not limited to, a review of the ROE formula and the capital structure)? Should the OEB adopt trigger mechanism(s) for a review and if so, what would be the mechanisms?

On page 153 of its evidence (bold added for emphasis, footnote omitted) LEI notes that:

> The OEB's 2009 decision established the process of periodically reviewing the cost of capital policy **every five years**. This five-year interval was found to "*provide **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*.

I support regular reviews of the cost of capital policy (and allowed ROEs) at regular intervals (ideally every three years, but never more than five years). I do note, as did LEI, that the last such review occurred in 2014, producing a report made available in 2016.

With respect to triggers that would open a review process aside from the required periodic reviews, under the OEB's current practice:[17]

> "*an applicant or intervenors can … file evidence in individual rate hearings in support of different cost of capital parameters due to their specific circumstances, but must provide a strong rationale and supporting evidence for departing from the OEB's policy;*"

In addition, utilities operating under Price Cap IR or Annual IR Index rate-setting plans have off-ramp mechanisms in place, which can trigger regulatory reviews if earnings fall outside a wide band. Both of these trigger mechanisms seem reasonable and pragmatic to me.

While I believe it is important to retain flexibility to apply judgement into the trigger mechanism process, as the OEB's current practice does, I do have one suggestion for a specific

[17] OEB. *2024 Cost of Capital Parameters.* October 31, 2023.

trigger mechanism that would be indicative of a period of extreme uncertainty in Canadian capital markets, which could significantly impact the validity of the parameters used in the ROE formula. In particular, if the Canadian A-rated utility yield spreads exceed 2%, I recommend an immediate and thorough assessment of existing capital market conditions. This could lead to a full regulatory review, depending on the results of this assessment. This is because, a spread greater than 2% would be indicative of a period of extreme uncertainty in Canadian capital markets. For example, over the January 2003-June 5, 2024 period, the average A-rated yield spread was 1.40%, with a minimum of 0.76% and with a maximum of 3.05% during December 2008, which was at the height of the financial crisis. However, for the most part, these spreads fluctuated but did not approach such high levels again. In fact, the 96th percentile for the spread over this period was 2.00%.

My recommendation is:

> 17) - I support regular reviews of the cost of capital policy (and allowed ROEs) at regular intervals (ideally every three years, but never more than five years).
> - The existing OEB trigger mechanisms and procedures that are in place are reasonable and should be retained.
>
> - In addition, I recommend that if the Canadian A-rated utility yield spreads exceed 2%, the OEB should undertake an immediate and thorough assessment of existing capital market conditions, which could lead to a full regulatory review, depending on the results of this assessment.

3.18 Mechanics of implementation – frequency for updating cost of capital parameters and/or capital structure of a utility

Issue 18: How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?

As LEI summarizes on page 159 of its evidence: "Changes in the OEB's cost of capital parameters are implemented once a utility files its cost of service application (i.e., upon rebasing)." I agree with LEI's opinion that this approach satisfies the FRS and is consistent with the objectives of promoting predictability and stability. As such, I recommend the OEB maintain the status quo, subject to any concerns regarding mitigation of significant resulting rate impacts.

My recommendation is in agreement with that of LEI:

18) I support the status quo.

3.19 Mechanics of implementation – approach for updating cost of capital parameters and/or capital structure for utilities in the middle of an approved rate term

Issue 19: Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?

The OEB currently applies any changes to cost of capital parameters and capital structure upon rebasing applications, with the changes not being applied in the middle of an approved rate term. This approach seems reasonable to me. In addition, I also support LEI's recommended addition to this policy, as summarized on page 163 of its evidence: "However, to ensure the FRS continues to be met, the OEB should also introduce an option for parties to request implementation of such changes prior to rebasing, so long as the two-factor test is met – (i) the utility should have more than 60% of its rate term remaining, and (ii) deviations in the cost of capital parameters should be material (100 bps or more)."

My recommendation is in agreement with that of LEI:

19) I support maintaining the current OEB approach, but also incorporating the additional option recommended by LEI.

3.20 Prescribed interest rates – appropriateness of existing methodology

Issue 20: Should the prescribed interest rates applicable to DVAs and the construction work in progress (CWIP) account for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be calculated using the current approach?

Currently, the OEB sets the prescribed interest rate for CWIP equal to the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate yield, which it applies to all projects under construction, regardless of duration of the construction period. I support continuing this policy, as does LEI.

The OEB's existing policy with respect to estimating prescribed interest rates for DVAs is to apply its estimate of the 3-month actual BA rate at the end of the month that is one month prior to the start of the quarter, plus a 25 bps fixed spread. As discussed in response to Issues #4 and #5, the use of the BA rate plus a spread is no longer appropriate since the BA rate will no longer be available, and Canadian banks are transitioning (and/or have already transitioned) to short-term debt products that are based on CORRA.

My recommendation, which is consistent with LEI's, is:

> 20) – Maintain the current approach regarding estimating the prescribed interest rate for CWIP.
>
> - Modify the existing practice for DVAs, as discussed in response to Issue #21.

3.21 Prescribed interest rates – recommended changes to existing methodology

Issue 21: If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?

As discussed in response to Issue #20, the application of the BA rate plus a spread is no longer appropriate since the BA rate will no longer be available. As a result, similar to LEI's recommendation, I suggest this approach be revised to align with the DSTDR methodology recommended in response to Issue #5.

My recommendation, which is consistent with LEI's, is:

> 21) The prescribed interest rate for DVAs should be revised to align with the recommended DSTDR methodology by using CORRA as the base rate instead of the BA Rate, where the base CORRA rate is estimated as the average of 3-month CORRA futures rates over the next 12 months, and the spread added to it is determined by sampling 6-10 banks to determine the appropriate R1-low rated utility spread.

3.22 Cloud computing deferral account – appropriate carrying charges for cloud computing deferral account

Issue 22: Should carrying charges and/or another type of rate apply to the Cloud Computing deferral account? *If so, what rate should be applied?*

I have not been asked to consider this issue.

4 REVIEW OF ECONOMIC AND CAPITAL MARKET CONDITIONS: PAST, PRESENT AND FUTURE (IN SUPPORT OF BASE ROE ANALYSIS)

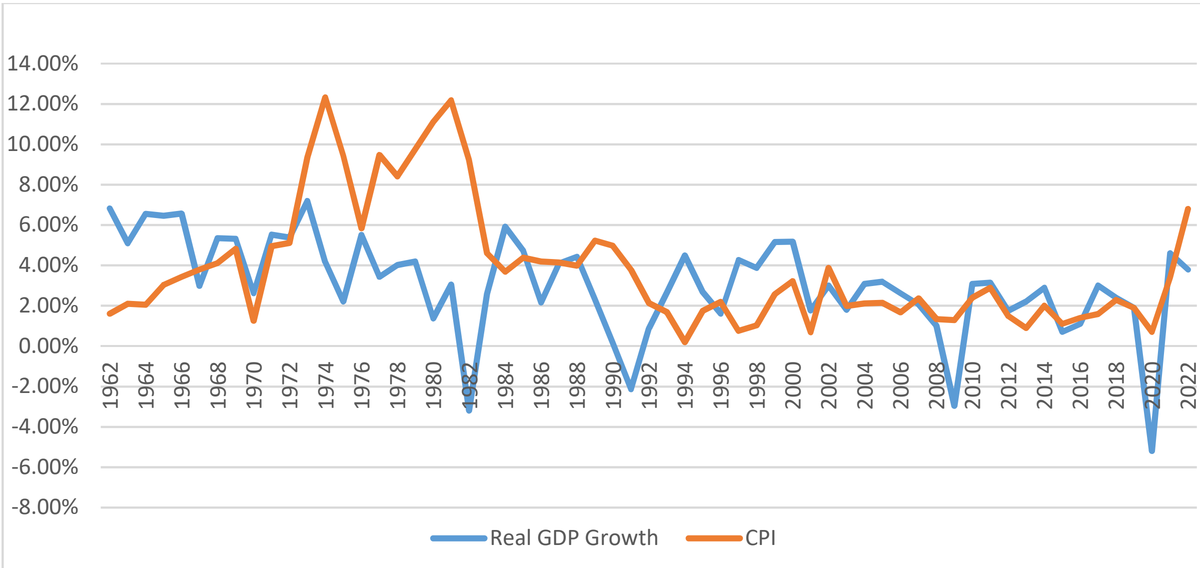
4.1 The Past and Present

4.1.1 GDP Growth and Inflation

Figure 1 below shows real GDP growth (%) and total inflation as measured by the Consumer Price Index ("**CPI**") over the 1962 to 2022 period. The graph shows that real GDP growth has generally been in the 2-6% range, with the exceptions of 2020 (due to COVID) and during three recessionary periods that occurred in the early 1980s, the early 1990s, and during the 2008-09 financial crisis. Table 1 reports summary statistics that show the average GDP growth over the entire period was 3.1% (median 3.0%). It is interesting to note that GDP growth declined to an average of **2.3% (median 2.7%)** over the 1992 to 2022 period, which is more in line with recent forecasts for future growth estimates. This represents the period following the Bank of Canada's initiation of a 2% inflation target in 1991, giving a year's grace period until its implementation had begun to take solid footing. This decline in average growth is accompanied by reduced volatility which is obvious from Figure 1, and also as measured by the standard deviation of 2.1% for 1992-2022 versus 2.4% for 1962-2022 as reported in Table 1. The working papers for Figure 1 and Table 1, below, are appended as Attachment B to my evidence.

FIGURE 1

REAL GDP GROWTH AND CPI – CANADA (1962-2022)



Data Source: Statistics Canada.

TABLE 1

REAL GDP GROWTH AND CPI SUMMARY STATISTICS – CANADA (1962-2022)

	1962-2022 (%)		1992-2022 (%)	
	Real GDP	**CPI**	**Real GDP**	**CPI**
Average	3.06	3.84	2.32	2.00
Geometric Average	3.06	3.80	2.30	1.99
Median	3.06	2.90	2.66	1.90
Max	7.20	12.33	5.18	6.80
Min	-5.20	0.20	-5.20	0.20
Std Dev.	2.40	3.04	2.10	1.22

Data Source: Statistics Canada.

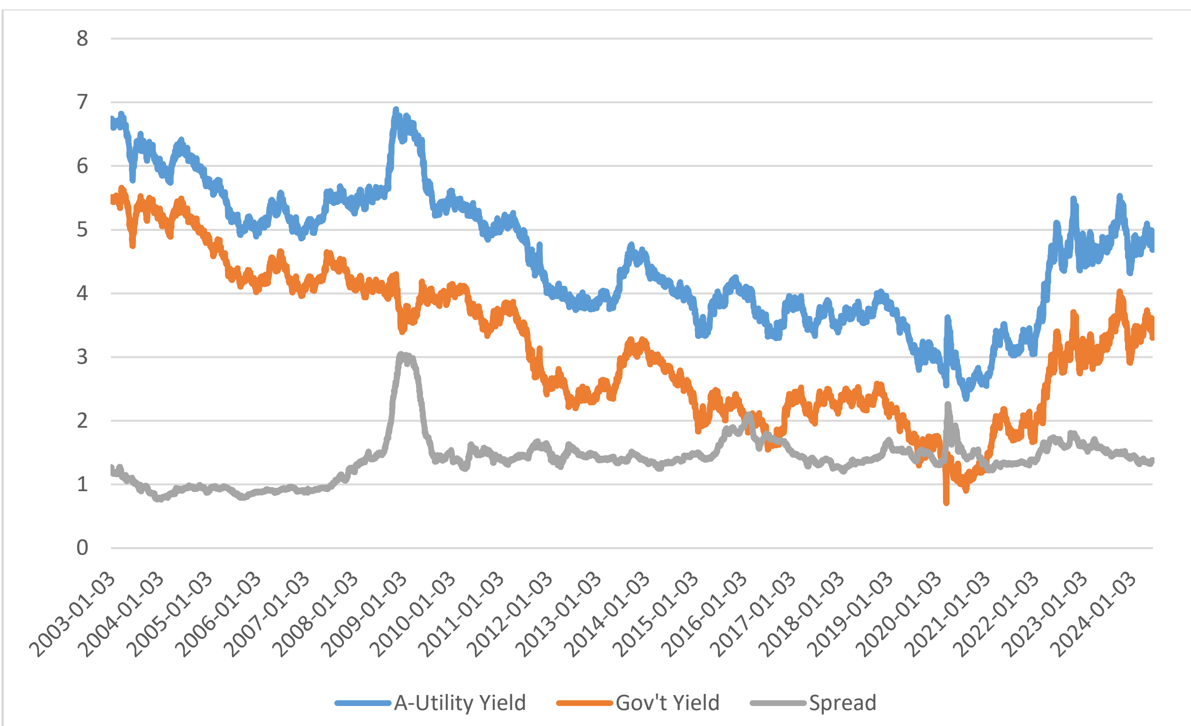
The 1962-2022 statistics are obviously driven by the high rates of inflation during the 1970s and 1980s. With the exception of 2022, where inflation hit 6.8%, rates have generally been within the Bank of Canada's 1% to 3% target range since the policy's adoption in 1991, being in line with the 2% target as evidenced by the average CPI of 2.0% (median 1.9%). CPI growth has also been very stable during this latter period, which is obvious from Figure 1, and also by the huge decline in standard deviation from 3.0% over the entire 1962-2022 period to 1.2% since 1991.

4.1.2 Capital Market Conditions

The 30-year Government of Canada bond yield as of June 5, 2024 was 3.30%, while the 10-year yield was 3.39%. The total cost of borrowing to utilities is a function of both the level of government yields and the yield spreads on utility bonds, both of which fluctuate through time. Figure 3 reports long-term government yields and A-rated utility yields over the 2003-2024 period. Both yields have fluctuated but generally moved together through time, with the average spread between the yields being 1.40% over the period. As of June 5, 2024 the A-rated utility yield was 4.68%, while the 30-year Government of Canada yield was 3.30%, which translates into an A-rated utility yield spread of 1.38%, virtually identical to the long-term average. The working papers for Figure 2 are appended as Attachment C to my evidence.

FIGURE 2

A-UTILITY YIELDS (January 1, 2003-June 5, 2024)

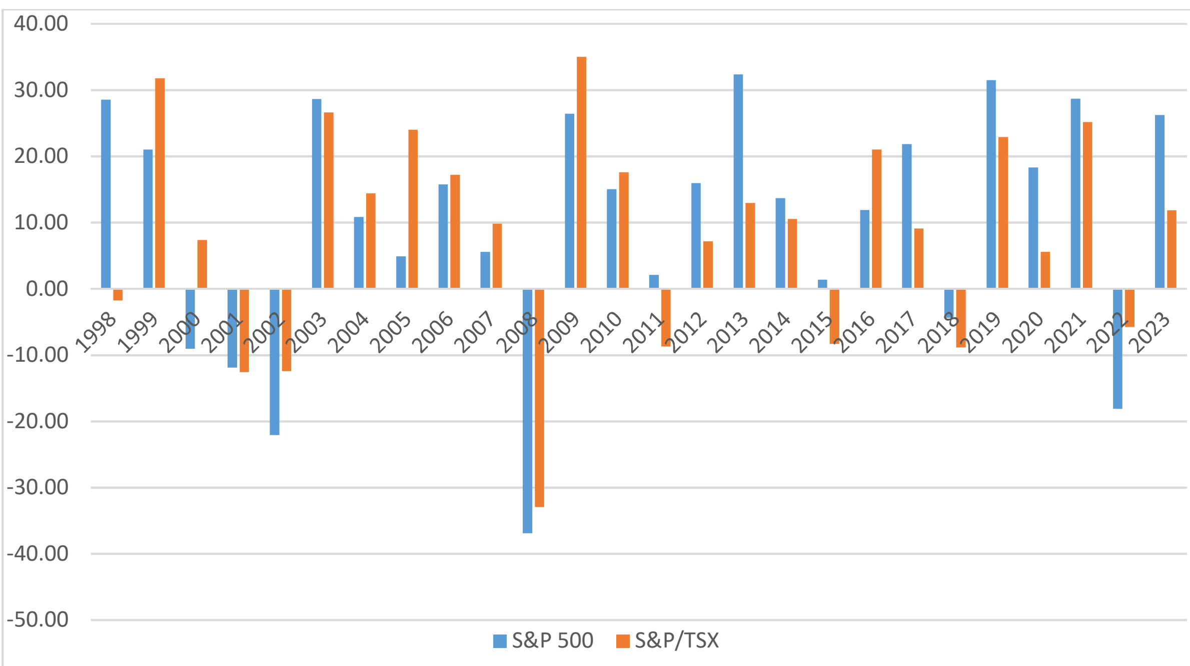


Source: Bloomberg.

Following a year of strong performance during 2021 with a total return of 25.2%, the Canadian stock market had a tough year during 2022, with a loss of 5.8%, but bounced back with an 11.8% return in 2023. U.S. markets did better than Canada in 2021 with a return of 28.7%, did much worse during 2022, producing a loss of 18.1%, but more than doubled Canadian performance in 2023 with a 26.3% return. Figure 3 provides the average annual total stock returns for Canada and the U.S. over the 1998-2023 period. Over this period, stocks in Canada provided an average return of 8.4% (geometric mean of 7.2%), while U.S. stocks provided an average return of 9.9% (geometric mean of 8.3%). The Canadian figures are consistent with long-term "real" stock returns in the 5% to 7% range, and current market return expectations (both of which are discussed in Section 3.2.3). The working papers for Figure 3 have been appended as Attachment D to my evidence.

FIGURE 3

STOCK MARKET RETURNS (%) - (1998-2023)



Source: Bloomberg

The trailing price-earnings (P/E) ratio for the S&P/TSX Composite Index stood at 15.7 on June 5, 2024, while the P/E ratio for the U.S. S&P 500 Index was 23.5 on that date. It is common to hear market observers suggest that the stock market is undervalued when P/E ratios fall below

15, or that they are over-valued when they exceed 20, which is the range of long-term average P/E ratios. While this is very simplistic, it does suggest that the current P/E ratios in the 12 to 20 range in Canada and the U.S. are in familiar territory; albeit slightly elevated in the case of the U.S., consistent with an extremely high return of 26.3% during 2023. For example, these figures are in line with the median P/E ratios for the TSX Index (16.7) and the S&P 500 Index (18.5) over the 2012-2022 period. As of the same date, dividend yields were 1.35% in the U.S. and 3.05% in Canada, also within typical ranges; albeit rather low in the case of the U.S. For example, the median dividend yields for the TSX Index and the S&P 500 Index over the 2013-2023 period were 2.99% and 1.89% respectively. The working papers supporting these statistics have been appended as Attachment E to my evidence.

The implied volatility indexes in Canada and the U.S. have averaged in the 16-20 range through time.[18] The Canadian (S&P/TSX 60) and U.S. VIX indices stood at 8.73 and 12.64 respectively as of June 5, 2024. The Canadian VIX indicates very low volatility, while the U.S. VIX also indicates well below average volatility.[19] It is important to recognize that these are short-term volatility measures.

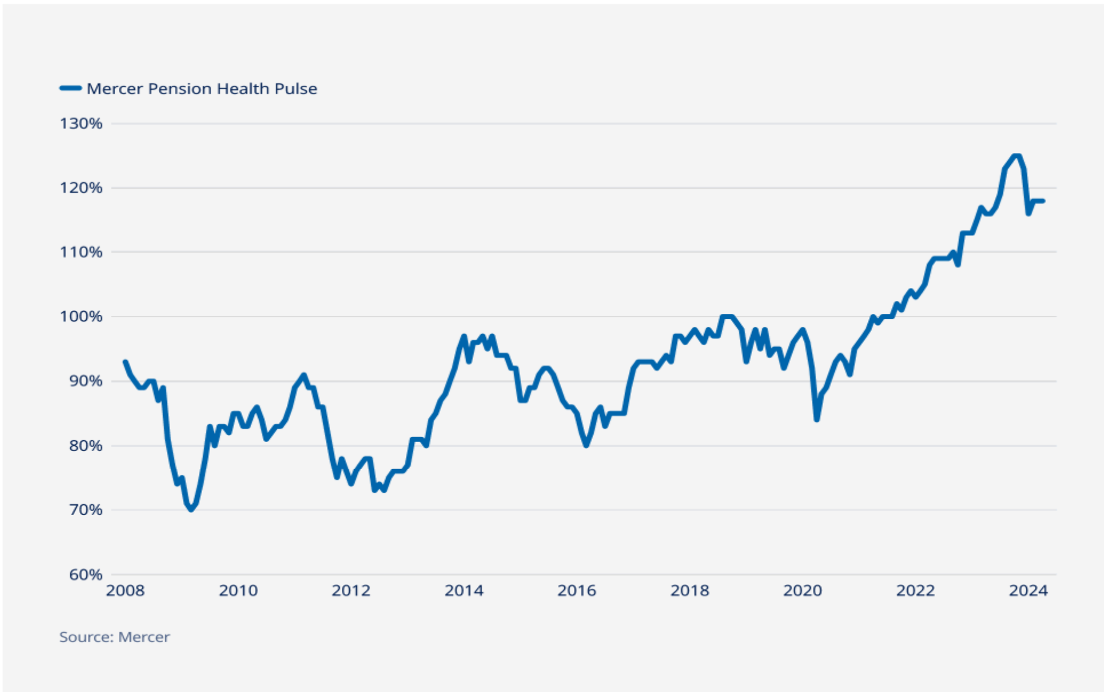
Finally, pension fund health is a closely watched and important financial health indicator. Poor stock returns during the 2007-09 crisis, combined with extremely low levels of interest rates, impaired the funding status of all pension funds. This created concerns that amounted to crises both at the individual and systemic levels. A commonly used measure of overall Canadian pension health is the Mercer Pension Health Index, which tracks the funded status of a hypothetical defined benefit pension plan. Figure 4 depicts the value of this index over the 2008 to Q1-2024 period. The index ended Q1 of 2024 at 118%, up from 113% at the start of 2024. The index has been above 100 since 2022, and well above the all-time low of around 70% in early 2009. Hence, this measure of financial stability indicates a return to stable and solid market conditions.

[18] For example, according to Mr. Hevert's 2018 evidence during the Alberta GCOC Proceedings (Exhibit 22570-X0153.01. pages 28-29), the U.S. index had averaged 19.5 since 1990, while the current Canadian index had averaged 16.6 since its inception in 2009.

[19] Sources: https://ca.investing.com/indices/s-p-tsx-60-vix, and https://www.google.com/search?client=firefox-b-d&q=VIX, June 10, 2024.

FIGURE 4

MERCER PENSION HEALTH INDEX - (2008-Q1, 2024)



Source: https://www.mercer.com/en-ca/about/newsroom/mercer-pension-health-pulse-q1-2024/, June 4, 2024.

4.2 The Future

4.2.1 Global Economic Activity

According to the Bank of Canada's April 2024 Monetary Policy Report (MPR), the global economy is expected to grow at around 3% annually over the 2024 to 2026 period, with 2024 and 2025 growth estimates increasing to 2.8% and 3.0% respectively from the Bank's January 2024 estimates of 2.5% and 2.7%.[20] Table 2 shows that this global growth is expected to be solid despite slow growth in the Euro zone of 0.4%, 1.2% and 1.7% during 2024, 2025 and 2026, and despite U.S. growth declining to 1.8% and 2.2% in 2025 and 2026 respectively. Meanwhile, Chinese GDP growth is expected at 4.7%, 4.4% and 3.9% in 2024, 2025 and 2026.

[20] This report is appended to my evidence as Attachment AI.

TABLE 2

REAL GDP GROWTH GLOBAL FORECASTS (2024-2026)

	Real GDP Growth (%)		
	2024	**2025**	**2026**
World	2.8	3.0	3.1
U.S.	2.7	1.8	2.2
Euro Zone	0.4	1.2	1.7
China	4.7	4.4	3.9

Source: Bank of Canada MPR (April 2024).

The Bank of Canada discusses several factors affecting global economic growth in its April 2024 MPR. The Bank suggests that global inflation has moved lower but is still above target for many central banks; however, financial conditions have improved as risk premiums have generally declined and interest rate decreases loom on several horizons. The Bank notes that the overall global impact reflects strong growth and slowing inflation in the U.S. economy, continued slow growth in the Euro area, and expected declines in China's economic growth due to a decline in consumer confidence arising from ongoing deleveraging in the property sector.

4.2.2 Canada's Outlook

The Bank of Canada predicts real GDP growth in Canada during 2024 of 1.5% (up from 0.8% in its January MPR), despite negative growth during the first half of the year. They predict growth will turn positive during the second half of 2024 and through 2025, as a result of improved financial conditions, as well as improvements in consumer and business confidence. Table 3 shows that the Bank further expects real GDP growth of 2.2% in 2025 and 1.9% for 2026. These forecasts reflect robust output growth during 2024 due to strong immigration offsetting weaknesses in productivity growth. While inflation has eased, it will remain slightly elevated; however, inflation and wage expectations are declining. Demand will be solid as a result of a rebound in consumer spending, alongside strong residential investment, business investment and demand for exports.

Table 3 also includes real GDP forecasts from RBC, CIBC World Markets, BMO Capital Markets, Desjardins, TD Bank, Scotiabank, OECD, and the IMF.[21] The average of the 2024 Real GDP forecasts of 1.10% is below that from the Bank of Canada (1.5%), as is the 2025 average forecast of 1.90% versus the Bank's forecast of 2.2%.

TABLE 3

REAL GDP GROWTH FORECASTS – CANADA (2024-2026)

	2024	2025	2026
RBC	1.3	2.4	
CIBC World Markets	1.0	1.6	
BMO Capital Markets	1.0	2.0	
Desjardins	1.2	1.8	
TD Bank	0.9	1.5	
Scotiabank	1.2	2.1	
OECD	1.0	1.8	
IMF	1.2	2.3	
Average	**1.10**	**1.90**	
Max	1.3	2.4	
Min	0.9	1.5	
Bank of Canada	**1.5**	**2.2**	**1.9**

Source: Attachments AI through AQ.

Based on the discussion above, the Bank expects inflation to fall below 2.5% during the second half of 2024 (with an overall inflation rate during the year of 2.6%). Table 4 shows that the Bank expects inflation to return to target range in 2025 (2.2%) and in 2026 (2.1%). Table 4 shows that the Bank's 2024 inflation projection of 2.6% is slightly above the average of the other forecasts of 2.5%, while its 2025 projection of 2.2% is slightly above the average forecast of 2.03%.

[21] These reports supporting the figures provided in Tables 3, 4 and some of the figures in Table 5 are appended to my evidence as Attachments AI through AQ.

TABLE 4

CPI FORECASTS – CANADA (2024-2026)

	2024	2025	2026
RBC	2.5	1.6	
CIBC World Markets	2.3	1.8	
BMO Capital Markets	2.6	2.1	
Desjardins	2.5	2.4	
TD Bank	2.5	2.1	
Scotiabank	2.6	2.2	
OECD	2.4	2.1	
IMF	2.6	1.9	
Average	**2.50**	**2.03**	
Max	2.6	2.4	
Min	2.3	1.8	
Bank of Canada	**2.6**	**2.2**	**2.1**

Source: Attachments AI through AQ.

Of course, there are always uncertainties associated with economic projections. The Bank noted that the three main upside risks to their inflation outlook are “higher house prices, elevated cost pressures and geopolitical developments.” The key downside risk to their inflation forecast would be a “a more pronounced slowdown in the Canadian economy,” which could result if the impact of restrictive monetary policy is stronger than expected, and/or if global growth is weaker than expected.

4.3 Capital Market Conditions and Expectations

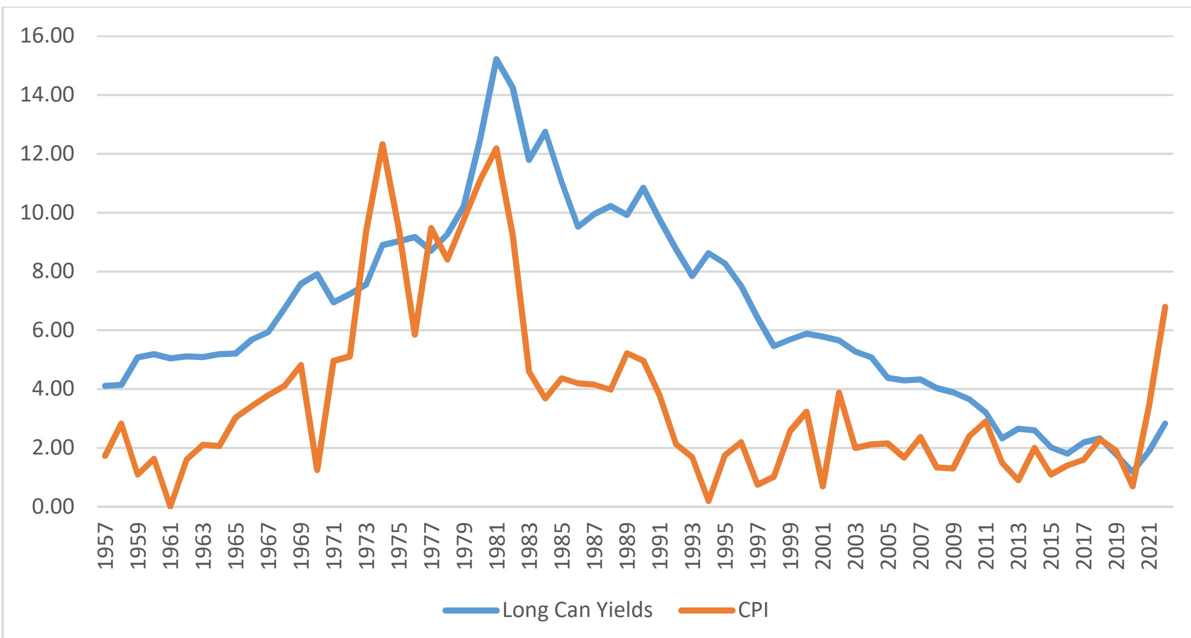
4.3.1 Debt Markets

What does all this mean for capital markets? I begin by looking at bond yields in particular. Figure 5 shows the relationship between long-term Canada bond yields and inflation since 1957. The graph shows that yields are closely related to inflation, with a correlation coefficient of 0.64 over the 1957-2022 period. Of course, yields are determined based on “expected” inflation, and we can see a few years in the 1970s and also in 2022, where actual inflation exceeded bond yields, since inflation greatly exceeded expectations. The decline in both inflation and yields since 1991 is obvious from the graph, with inflation hovering around the

2% target and bond yields declining and tracking inflation so that by 1998 they were below 6%, where they have remained ever since. It is this part of the graph that we should focus on, since this is representative of our current monetary regime, and during this period, long-term Canada bond yields averaged 3.61%, with inflation averaging 2.13%. Not only have long-term Canada bond yields not exceeded 6% since 1998, they have not exceeded 4.5% since 2005, or 4% since 2008.

FIGURE 5

BOND YIELDS AND INFLATION – CANADA (1957-2022)

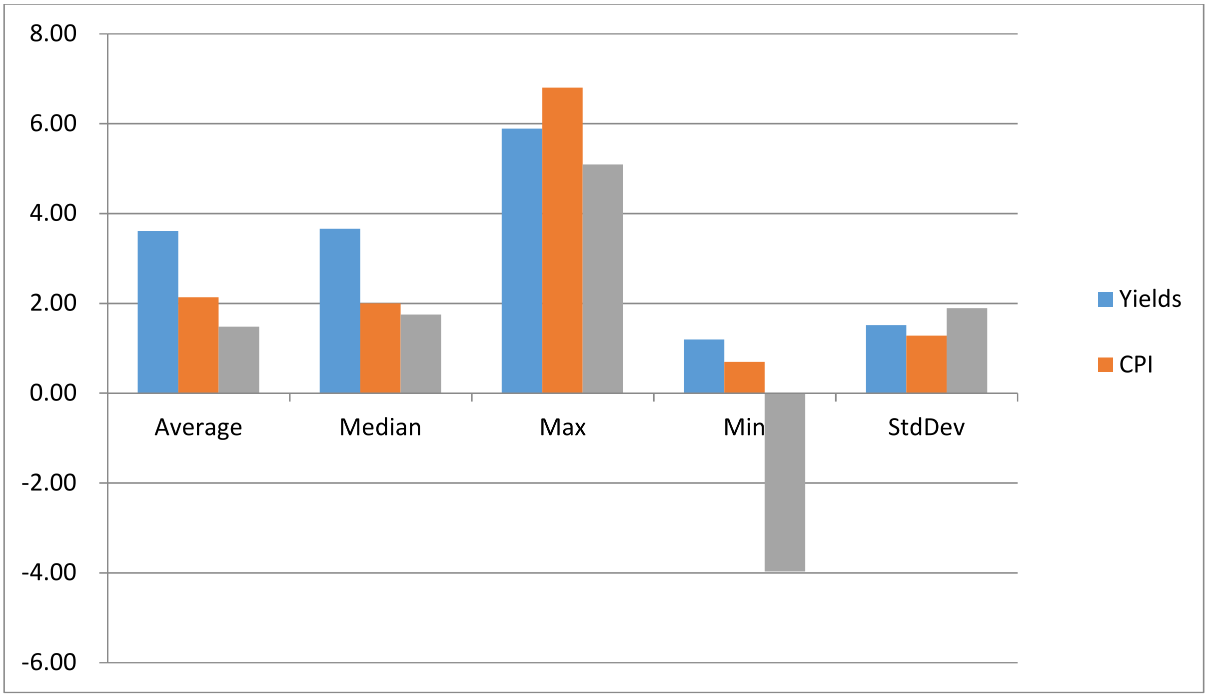


Data Source: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010012201#timeframe

It is noteworthy that the volatility in yields and inflation has decreased significantly since 1998, which is obvious from Figure 5. This can also be seen in the standard deviations reported in Figure 6, which reports summary statistics for the 1998 to 2022 period. For example, the standard deviation of the yields was 1.51% over this period, versus 3.26% over 1957-2022. Figure 6 also shows that the difference between yields and inflation averaged 1.48% over the 1998-2022 period, with a standard deviation of 1.89%. The working papers for Figure 5 and Figure 6 are appended as Attachment E to my evidence.

FIGURE 6

SUMMARY STATISTICS YIELDS AND INFLATION – CANADA (1998-2022)

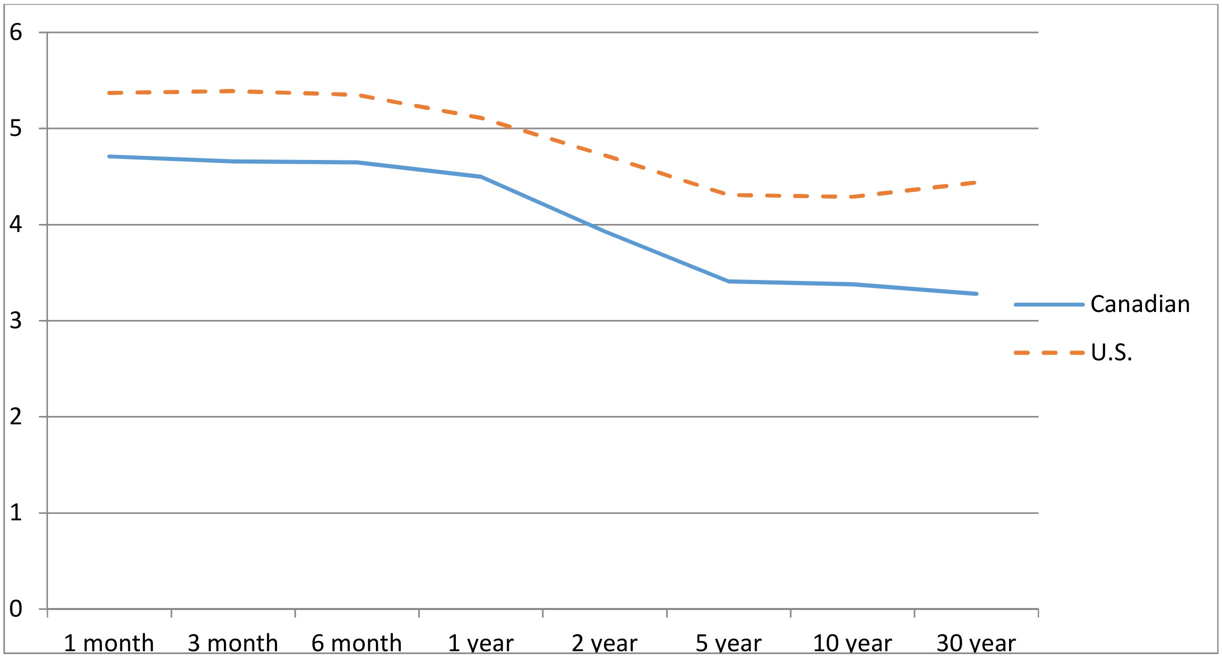


Data Source: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010012201#timeframe

Figure 7 below depicts the yield curves for Canada and the U.S. as of June 5, 2024. Both curves are similarly shaped, downward sloping curves, demonstrating that short-term rates are currently above long-term rates in both countries in anticipation of future reductions in interest rates. We can see that the short-term U.S. rates of one year or less were 0.6-0.7% above Canadian rates. Two year U.S. rates were about 0.8% higher, with 5- and 10-year U.S. yields being about 0.90% higher, and 30-year yields being over 1.1% higher. The working papers for Figure 7 are appended as Attachment F to my evidence.

FIGURE 7

YIELD CURVES – CANADA AND THE U.S. (JUNE 5, 2024)



Sources: U.S. Data - https://home.treasury.gov/policy-issues/financing-the-government/interest-rate-statistics?data=yield. Canadian data – https://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/, June 8, 2024.

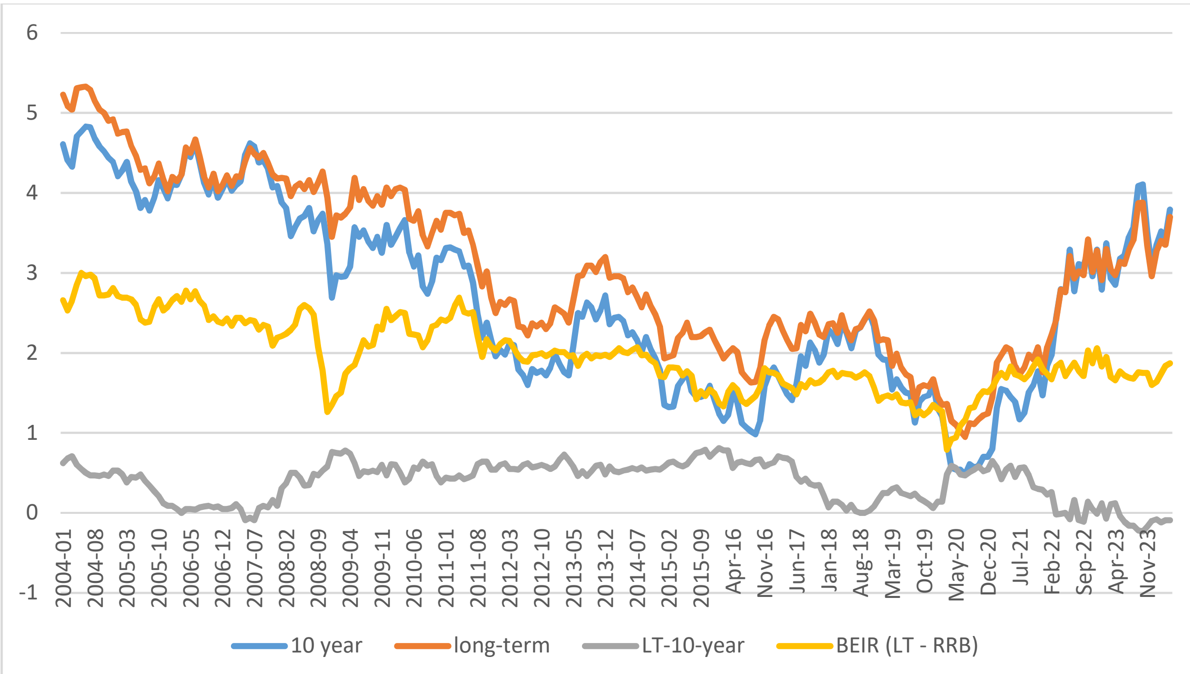
4.3.2 Interest Rate Levels

Figure 8 shows 10-year and long-term bond yields in Canada over the last 20 years, which have moved in tandem for the most part, with a correlation coefficient of 0.97 over the period. The graph also shows the spread between the two rates, which had an average (median) of 0.38% (0.47%) over the entire period. It is obvious from Figure 8 that this spread has narrowed considerably during the 2018-24 period, averaging 0.18% over these past six years, and sitting at -0.09% as of April 2024. Figure 8 also shows the break-even inflation rate (BEIR), which is the difference between the yield on long-term Canada bonds and the yield on Canadian Real Return Bonds. The BEIR is often viewed as an indicator of future inflation rates. This rate remained within the Bank of Canada's target band for inflation almost entirely over the entire period, peaking at 3.0% in 2004, and hitting a trough of 0.79% in March 2020, and averaging 1.97% overall, right at the Bank's target rate of 2%. It sat at 1.87% as of April 2024, well below both the Bank's 2024 CPI forecast of 2.6% and the average forecast of 2.5% from Table

4, and also below the Bank's 2025 CPI forecast of 2.2%. The working papers for Figure 8 are appended as Attachment G to my evidence.

FIGURE 8

SELECTED BOND YIELDS – CANADA (January 2004-April 2024)



Data Source: Bank of Canada website at http://www.bankofcanada.ca.

Table 5 includes the forecasts for Government of Canada 10-year bond yields from some of the largest Canadian financial institutions that were included in the GDP and CPI forecasts included in Tables 3 and 4. Forecasts were not available for all of the companies, but the average of the provided forecasts were 3.37% by December 2024 and 3.35% by March 2025 – so virtually the same. These forecasts were made during Q2 of 2024, when 10-year yields hovered in the 3.3 to 3.7% range, with a prevailing 10-year yield of 3.38% as of June 5, 2024, and so they were virtually identical to the existing yield on that date.

Despite the consistent inaccuracy of yield forecasts, if we assume the predicted increases occur fairly evenly throughout the year, this implies an average 10-year rate of approximately 3.36% during the year – virtually identical to existing 10-year yields of 3.38%. Using the June 5, 2024 spread between 10-year and long-term bond yield spreads of -0.08% we would get a 2025 forecast for long-term government yields of 3.28%, and using the 2020-April 2024 average spread between the two rates of 18 bp, we would obtain forecasts of 3.54%. If we used the long-term average 38 bp spread of 30-year yields over 10-year yields, we would obtain an estimate of 3.76%; although this would require a significant widening (i.e., 46 bp) from the current 10-year and long-term yield spreads of -0.08%. However, as discussed in Appendix A, there is compelling evidence that supports simply using the actual yields at a given point in time to predict future yields, and this is the approach I will employ in estimating future yields, which in fact makes little difference in this particular instance, since the forecasts essentially assume rates will stay the same as of June 5, 2024.

TABLE 5

10-YEAR YIELD FORECASTS – CANADA

	December 2024	March 2025
RBC	3.0	2.95
CIBC World Markets	3.3	3.2
BMO Capital Markets	NA	NA
Desjardins	3.35	3.15
TD Bank	3.25	NA
Scotiabank	3.35	3.5
Average	**3.37**	**3.35**
Max	3.35	3.50
Min	3.00	2.95

Source: Attachments AI through AQ.

4.3.3 Stock Markets

Predicting stock market performance in the short run is always fraught with uncertainties, and it is always much more productive to think in terms of long run expectations. Table 6 reports summary statistics for Canadian capital markets over the 1938 to 2023 period. The working papers for Table 6 are appended as Attachment A to my evidence.

TABLE 6

CAPITAL MARKET SUMMARY STATISTICS – (1938-2023)

1938-2023 (%)	CPI	Cdn. Stocks	Long Canadas	T-bills(91-day)	U.S. Stocks (in CAD)
Average	3.66	10.97	6.00	4.47	12.85
Median	2.78	11.05	4.14	3.73	13.45
Std. Dev.	3.31	16.16	9.45	4.16	17.05
Geo. Mean	3.61	9.75	5.59	4.39	11.53

Data Source: Data to 2008 are from the Canadian Institute of Actuaries; return data since 2009 are from Bloomberg, while the CPI data are from CANSIM. The 2023 CPI figure is the 2023 CPI estimate provided by the Bank of Canada in its April 2024 MPR.

The long-term average return in the Canadian stock market over this period was 10.97%, with a geometric mean of 9.75%. This occurred over a period in which inflation averaged 3.7% (geometric mean of 3.6%) and real GDP growth was higher than it has been recently. This implies “real” returns of approximately 7.3% (6.1%). If we combine these with long-term expected inflation of 2%, we would expect stock returns of 8.1% to 9.3% going forward. These numbers are higher than the average and also most current estimates of expected stock returns going forward by market professionals, as will be shown in Table 7 and as discussed in Section 5.2.3.

4.4 The Ontario Economy

The Conference Board of Canada (CB) April 2024 Ontario Five-Year Outlook, appended as Attachment AR to my evidence, estimates real GDP growth for Ontario of 0.6% during 2024 due to tight monetary policy, but that growth will bounce back to 2.3% in 2025 as the province experiences 2.9% growth in population, and as anticipated interest rate declines take hold. These growth estimates are also based on predictions that the labour market will be slow during 2024, but rebound during 2025, that the housing market will benefit from expected interest rate cuts, and that housing starts will increase during 2024. The CB further forecasts stronger growth would carry over into 2026, 2027 and 2028 with real GDP growth of 2.7%, 2.5% and 2.4% respectively. The CB estimated that provincial inflation would closely follow the Canadian CPI projections from the Bank of Canada, with forecast rates in 2024, 2025, 2026, 2027 and 2028 of 2.8%, 2.1%, 2.0%, 2.0% and 2.0% respectively.

5 ROE CALCULATIONS

5.1 Some Notes on Allowed ROEs

During testimony I provided at the EB-2022-0200 OEB Proceedings in 2023, I noted that allowed ROEs have not declined adequately in response to the reduction in the cost of capital that utilities have experienced, as long-term government bond yields (or RF) and A-rated utility bond yields have declined significantly over the last two decades. Figure 9 shows that since 2004, both RF and A-rated utility yields have declined markedly, while the allowed ROEs have declined much less so over this period. As a result, the spreads between allowed ROEs and these measures, both of which directly affect the utilities' cost of capital, have *increased* dramatically though the years. Figure 10 depicts these ROE-RF[22] and ROE-A yield "spreads," both of which have increased dramatically throughout this period.[23] For example, in January 2004, the allowed ROE by the OEB was 9.88%, at a time when 30-year government yields (RF) were 5.3% and A-rated utility yields (A yields) were 6.1%. So, the spread between the ROE and RF was **4.57%**, and between ROE and A yields was **3.78%**. As noted by LEI on page 103 of its evidence: "In EB-2009-0084, the OEB determined an LCBF of 4.25% and an ERP of 5.5%, which adds up to the Base ROE of 9.75% (4.25% + 5.5%)." As of June 5, 2024, the allowed ROE was 0.67% lower than in 2004 at 9.21%, while RF was 2.0% lower at 3.30%, and A yields were 1.42% lower at 4.68%. As a result the ROE-RF spread was 1.34% higher than in 2004 at **5.91%** (a 29% increase from 2004), while the ROE-A yield spread was 0.75% higher at **4.53%** (a 20% increase). The average ROE-RF spread during the January 2004-June 2024 period was 6.03%[24] and the average ROE-A-yield spread was 4.61%.[25] Unfortunately,

[22] The spread between the ROE and RF can be viewed as the ex-post equity risk premium (ERP) as referenced by LEI in its evidence.
[23] The working papers for Figures 9 and 10 are appended as Attachment H to my evidence.
[24] As mentioned previously, this is equivalent to using the CAPM and using a market risk premium (MRP) estimate of 6%, which is at the high end of traditionally employed estimates, and simultaneously using a beta for Ontario utilities of 1.0 (which is more than double the long-term average beta for Canadian utilities of about 0.35). Or alternatively this 6% figure could result if we used a beta of 0.5 for utilities, but then used an MRP of 12% - which far exceeds any estimates ever used for this variable.
[25] As mentioned previously, this is equivalent to using the bond yield plus risk premium approach to estimate the cost of equity, and using a risk premium estimate of 4.6%. This number is close to the maximum range of traditional estimates used (i.e., in the 2.0-5.0% range) – and would apply to high risk companies, and clearly not to regulated operating utilities, which will be well below average risk – so something less than 3.5% should be used – and I use 2.5%.

the fact that allowed ROEs have not decreased in North American jurisdictions (including Ontario) proportionately to changing capital market conditions and the associated reduction in the costs of capital to utilities has resulted in awarded ROEs that have been well in excess of the utilities' cost of equity, with the excess costs being borne by consumers.

FIGURE 9

ALLOWED ROES, GOVERNMENT YIELDS

AND A-RATED UTILITY YIELDS (January 2004-June 5, 2024)

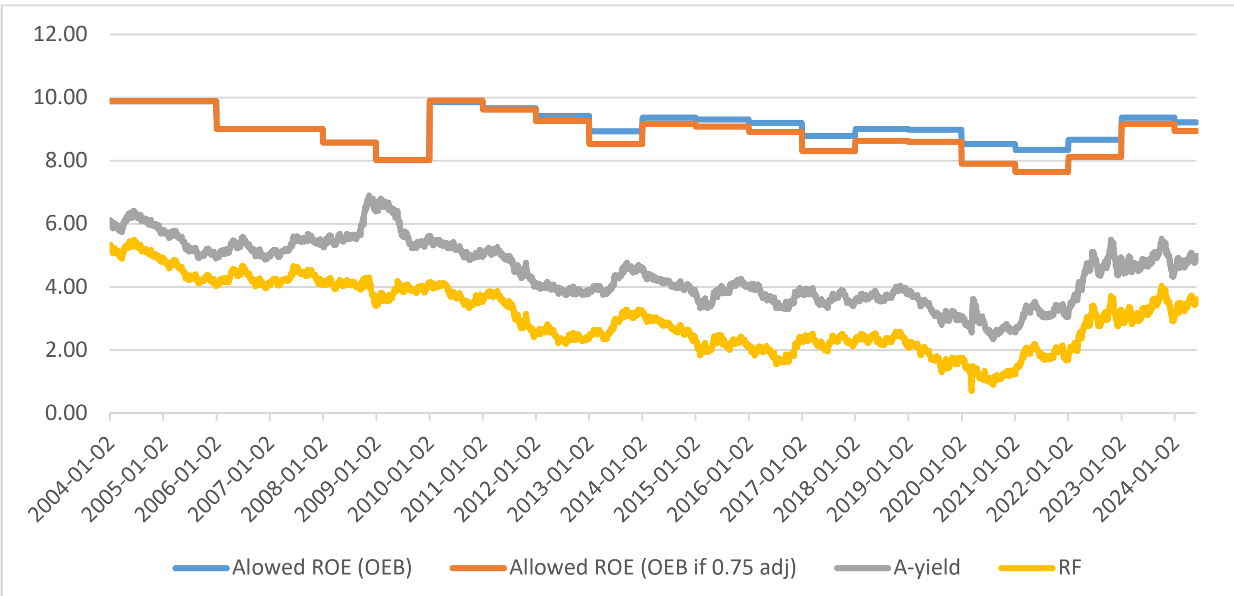
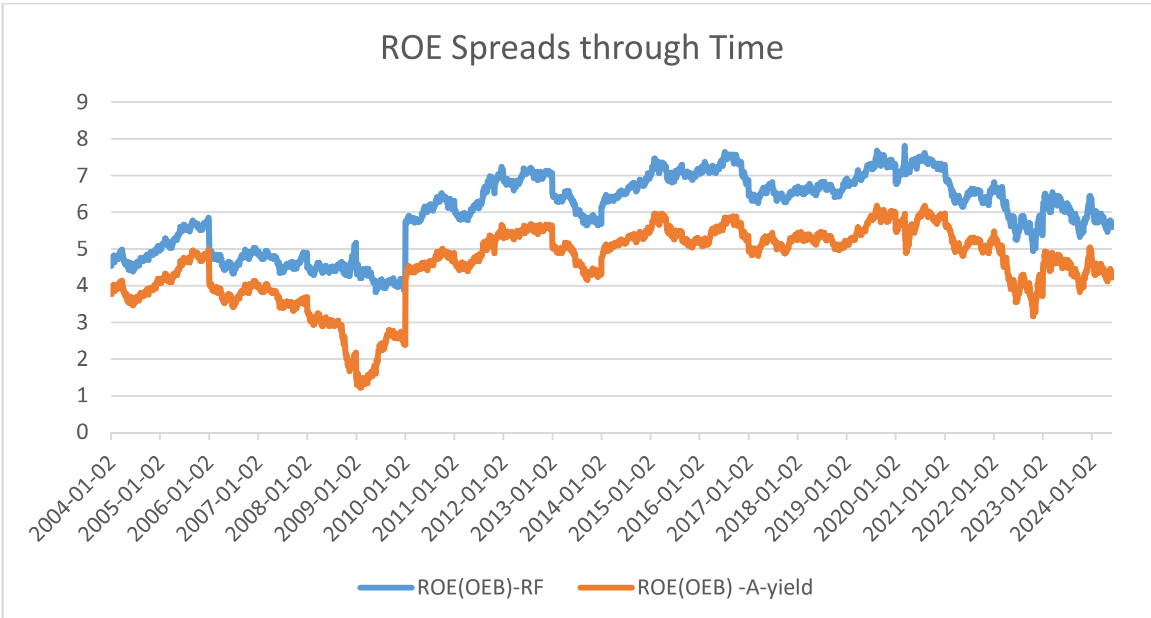


FIGURE 10

ALLOWED ROE-RF and ROE-A-YIELD SPREADS

(January 2004-June 5, 2024)



For illustrative purposes, as the OEB reconsiders its existing ROE formula, Figure 9 also includes the OEB allowed ROEs that would have resulted if the OEB had used an adjustment factor of 0.75 instead of 0.5 for both terms in their ROE formula (i.e., the change in government yields factor and the change in A-rated utility yield spreads), since the formula's implementation being reflected in 2010 and subsequent allowed ROEs. The graph shows that increasing the adjustment factors makes allowed ROEs more responsive to changing market conditions than using 50% adjustment factors. This is reflected in lower resulting June 5, 2024 RF-Allowed ROE and A-yield spreads of 5.64% and 4.26% respectively for this approach, which are about 30bp lower than the actual spreads. Similarly, the averages for the RF and A-yield to allowed ROE spreads over the period, which were 5.80% and 4.39% respectively, about 20bp below the actual average spreads over this period.

It may also be useful for the Board to compare the allowed ROEs using its existing formula to those determined in another Canadian jurisdiction that determined allowed ROEs during regular proceedings and which did not use an automatic adjustment ROE formula over this time period (until recently implemented for 2024). While not reported in Figures 9 or 10, the workpapers for those figures includes the allowed ROEs for Alberta utilities over the same period. The worksheet included as Attachment H shows that the allowed ROEs for Alberta over this period generated RF-allowed ROE and A-yield-allowed ROE spread averages that were 5.63% and 4.21% respectively, about 20bp below the OEB at 0.75 adjustment spreads, and about 40bp below the actual OEB average spreads over this period.

As noted in response to Issue #10, the downward "stickiness" in awarded ROEs noted above is not unique to Ontario but can be observed in other Canadian jurisdictions, and is even more prevalent in the U.S., which is evidenced in the results of a 2017 study that examines "a dozen years' of gas and electric rate-setting decisions" in the U.S. and Canada over the 2005-2016 period.[26] This study provides evidence "demonstrating empirically that allowed returns on equity diverge significantly and systematically from the predictions of accepted asset pricing methodologies in finance." A large part of this can be explained by the fact that allowed ROEs "tend to exhibit considerable stickiness around focal 'odometer' points." Consistent with the evidence for Ontario and Alberta discussed above, the authors note that "awarded ROE spreads over risk free treasuries have progressively *widened* significantly since 2005, even though systematic risk in the utilities industry has *fallen continuously* during the same time period." As a result, the authors find that:

> Indeed, if the awarded ROEs were an asset class, they would generate a mean positive abnormal return ("alpha") of between 7.5 and 8.5 percent, an amount that overshadows even the performance of Fortune Magazine's top twenty stock investments for the last decade.

A recent study by Sikes (2022) entitled "Regulatory Inequity" shows that the average awarded ROE is much greater than the average utility's cost of equity, which means that any investments undertaken by the utilities create excess value (i.e., generate economic rent).[27] Sikes examines the FERC's Opinion 569-A, issued in May 2020 as a case study to examine the appropriateness of allowed ROEs at a broader level, since the decision and the decision process are typical of most rate decisions, noting (on page 4) that:

> It is in fact an apt case-study which encompasses the prevailing methodologies used, in one form or another, by utility commissions throughout the nation to determine the ROE. As such,

[26] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2994314). Appended to this evidence as Attachment AE.

[27] Source: Sikes, Thomas, M. S. January 2022, "Regulated Inequity – How regulators' acceptance of flawed financial analysis inflates the profit of public utility companies in the United States". Appended to this evidence as Attachment AF.

> examination of the fallacies behind Opinion 569 reveals in general how regulators' acceptance of flawed financial analysis inflates the profit of public utilities.

Sikes notes flaws in the implementation of Risk Premium methodologies and DCF analysis, which lead to upwardly biased estimates. He suggests that the CAPM is the only viable approach, but goes on to note that typical CAPM estimates are also upwardly biased due to **typical implementation flaws such as the use of adjusted betas and market risk premiums that greatly exceed current expectations of market professionals**. He goes on to conclude (page 71 – bold added for emphasis) that "[g]enerations of utility regulators and financial analysts have become inculcated in the idea, at least implicitly, that utilities are fairly compensated with an ROE similar to that expected from the average firm. Because of this, there will be **inertia in moving towards the truly just and reasonable ROE."**

5.2 Capital Asset Pricing Model (CAPM) Estimates

5.2.1 CAPM Overview

This section employs the commonly used CAPM to estimate the appropriate allowed ROE for a typical regulated Ontario utility. Essentially CAPM can be used to estimate the required ROE (or Ke) for a firm from the point of view of a well-diversified investor. It can be presented as:

Ke = RF + (ERm – RF) Beta

Where,

Ke = required rate of return on common equity

RF = the risk-free rate

ERm – RF = the market risk premium or MRP (i.e., expected market return (ERm) minus RF)

Beta = the measure of market risk of a security

This model is widely used:

- by over 68 percent of financial analysts;[28]
- by over 70 percent of U.S. CFOs;[29]
- by close to 40 percent of Canadian CFOs.[30]

Of course, the CFOs and analysts are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital considerations. It has also been heavily relied upon in previous decisions, which is appropriate in my opinion, and as recommended by Sikes (2022).

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[28] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. This presentation is appended to this evidence as Attachment AS.

[29] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243. This article is appended to this evidence as Attachment AT.

[30] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011. This article is appended to this evidence as Attachment AU.

A recent study by Berk and van Binsbergen (2017)[31] also provides support for the use of CAPM as the most widely used model by investors, stating:

> We find that investors adjust for risk by using the beta of the capital asset pricing model (CAPM). Extensions to the CAPM perform poorly, implying that investors do not use these models to compute discount rates.[32]

The authors go on further to highlight the fact that this model should be used by practitioners, despite its limitations, quite simply because it is the most widely used model by investors, who in turn drive equity returns:

> We have demonstrated that among a range of proposed models, the CAPM—though perhaps far from being a perfect model of risk—is most consistent with investor behavior. Thus, if the criterion for deciding how to compute the discount rate is to use the method investors use, **practitioners should use the CAPM**.[33]

5.2.2 Estimating RF

Technically, the CAPM is a one-period model, and the government T-bill rate should be used as the appropriate RF, since it is virtually guaranteed and does not fluctuate. However, it is common practice to use the CAPM to estimate the required return on common equity over many periods, such as when trying to estimate the cost of a firm's common equity financing component when estimating the firm's overall cost of capital. Under these circumstances, it is appropriate to use the yield on long-term government bonds instead of T-bills since they are more representative of the rate that could be obtained over longer investment horizons. This practice is consistent with previous decisions.

As discussed in Section 4.3.2, the evidence provided in Appendix A supports that using the actual yields at a given point in time to predict future yields performs far superior to both using Consensus forecasts or using the mid-point of actual yields. As a result, I will use the existing long-term government yield of **3.30%** as of June 5, 2024 as my estimate for **RF**.

[31] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32. This article is appended to this evidence as Attachment AV.

[32] *Ibid.*, page 25.

[33] *Ibid.*, page 32.

5.2.3 Expected Market Returns and Estimating MRPs

The next CAPM input is the Market Risk Premium (MRP), which is measured by the expected long-term return on the equity market less the long-term government bond yield, which measures RF. Table 7 below provides useful guidance in determining a reasonable estimate for expected stock market returns, which in turn can be used to estimate MRPs, or to assess the reasonableness of MRP estimates. It is broken into two categories: (1) historical returns; and, (2) current (i.e., 2022-24) long-term market forecasts from 4 different sources. It is noteworthy that one of the sources of long-term forecasts (i.e., Horizon) provides summary statistics based on extensive surveys of finance professionals, and hence Table 7 provides a comprehensive view of the forecasts of the professional finance community. In particular, Horizon's report is based on the forecasts of 42 investment advisors, which includes prominent advisory firms (e.g., Aon, Mercer, and Willis Towers Watson), several large commercial and investment banks (e.g., Bank of New York Melon, Goldman Sachs Asset Management, J.P. Morgan Asset Management, Merrill, Morgan Stanley, UBS, etc.), and large asset managers (e.g., BlackRock, The Vanguard Group, etc.). As such, it provides a comprehensive representation of the views of finance professionals managing trillions of dollars of wealth.

Sikes (2022) (page 45) verifies the relevance of expected market returns by the financial community, noting "investors' expected market return should effectively set a ceiling on the ROE approved by regulators as utility stock is less risky than the overall stock market." The AUC for example, has also previously noted that such forecasts are informative and reaffirmed this position in the 2018 Alberta GCOC Decision, stating:

> Consistent with its determinations in previous GCOC decisions, the Commission continues to hold the view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities.[34]

Hence, the AUC believes that such information is relevant, and I agree. In fact, I would argue that the beliefs of professionals who participate in the markets and influence market activity are far more relevant than market expectations determined using unrealistic growth assumptions, such as those I have seen provided by the utilities' experts in previous proceedings. In other words, market participant beliefs represent an important and practical

[34] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 97, para. 460.

"benchmark," against which any utility ROE estimate must be compared. Table 7 provides Canadian, U.S. and global historical evidence and forecasts; however, since I estimate the CAPM using the Canadian stock market, I focus my discussion on the Canadian evidence; although I would note that the expected U.S market return according to industry professionals of 6.84% is not that far off the Canadian average estimate of 6.1%, both of which are below my final estimate for expected market returns.

TABLE 7

HISTORICAL AND FORECAST EQUITY RETURNS

Source	**Horizon**	**Canada**	**U.S.**	**World / Developed Markets (excl. U.S.)**
HISTORICAL RETURNS				
1. Historical Data (Cleary Evidence, Table 6, Section 4.3.3)	Historical: 1938-2023	Real: 6.1% GA 7.3% AA		
2. Dimson, E., P. Marsh, and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[35]	Historical: 1900-2015	Real: 5.6% GA 7.0% AA	Real: 6.4% GA 8.3% AA	Real (World Excl. U.S.): 4.3% GA 6.0% AA
3. "The Real Economy and Future Investment Returns," McKinsey & Company, January 17, 2017.[36]	Historical: 1915-2014		Real: 6.5%	
Average (Range)		**Real:** **6.5%** (5.6%-7.3%)	**Real:** **7.1%** (6.4%-8.3%)	**Real:** **5.2%** (4.3%-6.0%)
FORECAST RETURNS				
4. . Institut québécois de planification financière (IQPF) and Financial Planning Standards Council (FPSC), "Project Assumption Guidelines," April 2024. Source: https://www.fpcanada.ca/docs/default-source/standards/2024-pag---english.pdf[37]	Long-term forecast	Nominal: 6.4%		Nominal: 6.5% (Foreign developed market equities)
5. Horizon Actuarial Services, LLC, "Survey of Capital Market Assumptions," 2023. Source: https://www.horizonactuarial.com/_files/ugd/f76a4b_1057ff4efa7244d6bb7b1a8fb88	Intermed. (<10 years) Long-term		U.S. Large Cap (Nominal) 6.90% (4.8-10.2%) 7.37%	Non-US Dev. Mkts. 7.49% (4.7-10.3%) 7.78%

[35] Appended to this evidence as Attachment AW.
[36] Appended to this evidence as Attachment AX.
[37] Appended to this evidence as Attachment AY.

236e6.pdf[38]	(10-years or more)		(5.6-10.2%)	(6.1-9.8%)
6. Franklin and Templeton Investments, "Capital Market Expectations 2024 and Beyond," December 2023.[39] Source: https://pages.to.franklintempleton.com/rs/848-IAP-939/images/Outlook%202024%20Event_ian.pdf?version=0	10-year forecast	Nominal: 7.2%	Nominal: 7.4%	Nominal: EAFE Equities: 8.6%
7. "Capital Market Assumptions" BlackRock, May, 2024.[40] https://www.blackrock.com/institutions/en-us/insights/charts/capital-market-assumptions	10-year forecast 20-year forecast	Large Cap - Nominal: 4.01% 5.19%	Large Cap – Nominal: 5.42% 6.53%	World excl. Can (in CAD): Nominal: 5.29% 6.39%
Average (Range)		**Nominal: 6.1%**[41] (4.0%-7.2)	**Nominal: 6.84%** (5.4%-7.4%)	**Nominal: 7.14%** (5.3%-8.6%)

The first three sources in Table 7 provide historical long-term real returns for Canadian, U.S. and global stocks over three extremely long time periods (i.e., 86 years, 116 years and 100 years). The Canadian evidence suggests average real returns of 6.5%, with a range of estimates of 5.6% to 7.3%. Combining these figures with 2% expected inflation would suggest expected nominal returns of 8.5%, ranging from 7.6% to 9.3%, based solely on historical results.

The next four sources represent 2023-24 estimated long-term market returns from a number of important and reputable sources with various mandates (i.e., the Financial Planning Standards Council; consulting firms, investment and commercial banks, and other investment management firms). All of these estimates are provided in nominal terms. The Canadian market nominal estimates range from 4.0% to 7.2%, and average **6.1%.** Deducting the 2% expected inflation, this translates to an average *real* return of 4.1%. In other words, most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term *real* rates of return in the 5.6-7.3% range over the next 10-20 years.

[38] Appended to this evidence as Attachment AZ.
[39] Appended to this evidence as Attachment BA.
[40] Appended to this evidence as Attachment BB.
[41] This average is determined by taking the average of BlackRock's two forecasts and using it as one of three estimates (i.e., three different sources).

While I do not focus on the U.S. evidence, it is noteworthy that the average expected market return for U.S. stocks is 6.84% - well below its average of the last few decades. This is important to recognize, as it indicates that expected market return (and related MRP) forecasts that rely heavily on recent U.S. stock returns (such as that done by LEI which uses historical averages from five recent U.S. time periods in estimating potential MRPs), will be overly optimistic. In fact, it is well-known that the U.S. stock market has experienced exceptional returns over the last few decades, producing abnormally high real returns relative to its longer term history, and relative to global equity returns in other markets. I have attached an article as Attachment AD, which expands on this matter. The authors note that: "The real return on U.S. stocks from 1950 through 2023 was 7.63 per cent, and 7.16 per cent for the 20 years ending December 31, 2023. A real return above 7 per cent is exceptional even for the U.S. market. From 1900 through 1950, U.S. stock returned a real annualized 5.57 per cent." They further note that "Global real stock returns from 1900 through 2023 were 5.16 per cent annualized" (based on analysis of 38 developed markets). Putting this in perspective, they note that: "The often cited 10-per-cent return for stocks based on the post-1950 period is roughly equivalent to a 7-per-cent real return in the historical data. That is about 2 per cent higher than unbiased estimates of U.S. expected returns, U.S. equity returns before 1950 and global stock returns spanning 1890 through 2023." Similar to the U.S. stock returns forecast by investment professionals reported in Table 8, the authors expect future real returns for U.S. stocks in the 4.25% range, and combine this with 2.5% expected inflation to arrive at an expected U.S. stock market return of 7.24%, much more in line with the nominal forecasts provided in Table 8.

I believe that both historical returns and current expectations of market professionals represent the best sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table 7 and discussed above suggests a range of estimates in the 4.0% to 9.3% range, and the mid-point between historical averages (when adjusted to nominal terms) of 8.5% and the forecast average of investment professionals which is 6.1%, of 7.3%. This is consistent with my usual recent assumptions that an appropriate range for expected long-term Canadian stock market returns is 6-9%, and that the mid-point of **7.5% represents an appropriate point estimate**.[42] This is

[42] This estimate of 7.5% for future expected Canadian market returns is reflective of my analysis of historical market returns and forecasts for future returns from investment professionals discussed above. Attachment BC

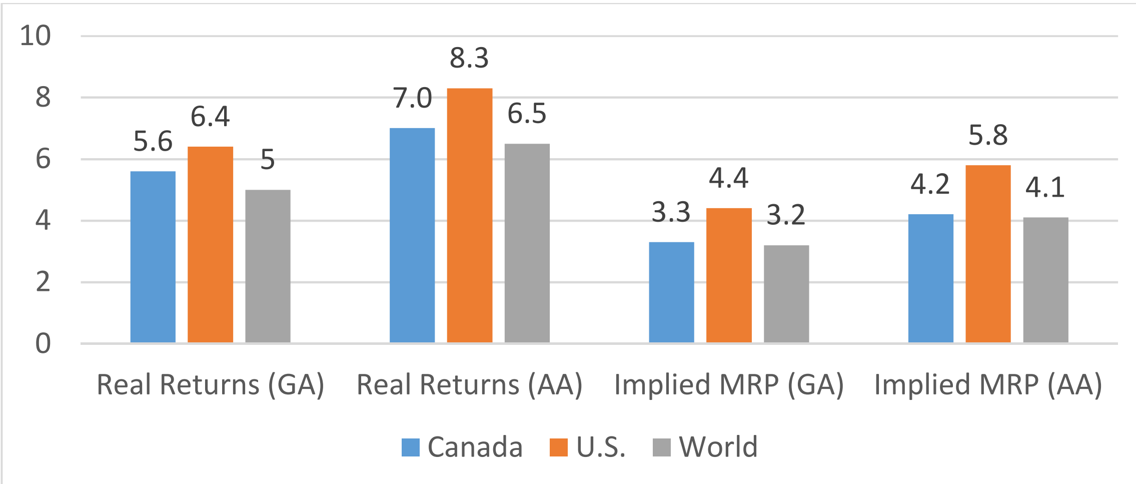
well above the consensus view of financial professionals of 6.1% that is estimated in the bottom portion of Table 7, but below historical averages, so it seems reasonable. It is important to recognize that this expected market return of **7.5%** represents an **upper bound** for the cost of equity to regulated utilities (before adding 0.50% for flotation costs), since they are less risky than the average company in the market. This aligns well with my DCF estimate for the market of 7.40% (in Section 5.2.2), but is below my implied CAPM estimate for the market of 8.3% (discussed later in this section).

Figure 11 shows that the world market MRP, as measured by the return on the market less the long-term government bond yield over the 1900-to-2015 period, provided an arithmetic average of 4.1% (geometric mean of 3.2%). These means are lower than the corresponding U.S. figures (5.8% and 4.4%) and slightly below the Canadian figures (4.2% and 3.3%) over that period. The figures for Canada are in line with the differences between the average (and geometric mean) returns for Canadian stock and bond returns over the 1938 to 2023 period, which were 4.97% (4.16%) as previously reported in Table 6. These numbers are also consistent with expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6% range for most regions. The results for Canada and the U.S. are reported in Figure 12, with 2024 figures of **5.2%** and 5.5% respectively.

provides a July 3, 2024 article (published after I had made this estimate) discussing the iShare S&P/TSX 60 Index ETF (XIU). The article confirms the reasonableness of my estimate, suggesting that: "The average annual total return since inception for XIU is 7.6 per cent. If you invest in big Canadian companies, that's your benchmark for measuring returns over periods of 10 years and longer."

FIGURE 11

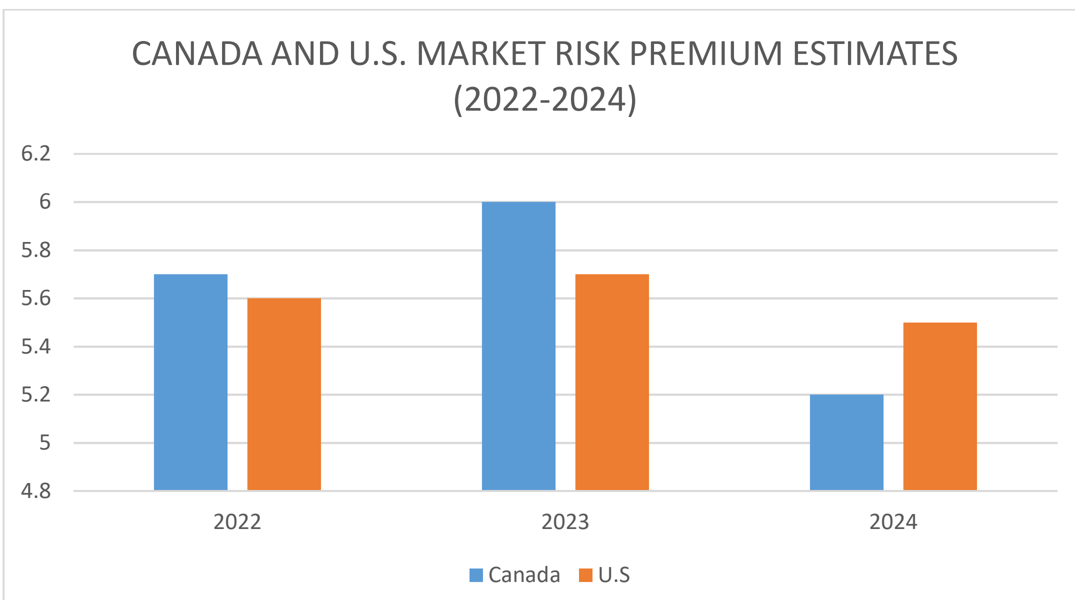
CANADA, U.S. AND GLOBAL MARKET RISK PREMIUMS (1900-2015)



Source: Dimson, E., Marsh, P. and M. Staunton, "Long-Term Asset Returns," in *Financial Market History*, CFA Institute Research Foundation, December 2016.[43]

FIGURE 12

CANADA AND U.S. MARKET RISK PREMIUM ESTIMATES (2022-2024)



Source: "Survey: Market Risk Premium and Risk-Free Rate used for 96 countries in 2024," 2024 Fernandez et. al. [44]

[43] Appended as Attachment AW, noted previously.
[44] Appended as Attachment BD.

Based on the previous discussion of capital markets in Section 4.1.2, it appears that stock markets reflect fairly normal conditions in terms of P/E ratios, dividend yields and below average market volatility as measured by the VIX and Canadian VIX indexes. Therefore, I use an **MRP of 5%**, which is the mid-point of the commonly used 4-6% range. This figure equals the 4.97% average difference between Canadian stock and government bond returns over the 1938-2023 period, is 1.7% above the long-term geometric mean MRP of 3.3% estimated by Dimson et al., and is slightly above the mid-point of 4.7% of the long-term arithmetic average Canadian MRP of 4.2% and the 5.2% forecast MRP documented by Fernandez et. al (2024). It is also consistent with the practice of using 6% when market uncertainty is well above average, using 5% when markets are close to normal, and using 4% during periods of extreme market and economic optimism.

I know from having read numerous investment reports and from having seen numerous presentations from finance professionals that it is common practice to use a range of 3-7% for the MRP when using the CAPM to estimate required returns of equity for firms, with the large majority of MRP estimates falling in the 4-6% range, as noted by Sikes (2022), who cited two market surveys[45], and one research article[46] to support this assertion. In fact, it is so common to use MRPs between 4 and 6%, it is almost assumed. Similarly, it has also always been the case that the MRP would be adjusted upwards during higher periods of uncertainty, and downwards during periods of less uncertainty. I provide some strong evidence below regarding MRPs which is included in two research articles written by prominent finance professors.

In a 2013 working paper, Aswath Damodaran discusses MRP estimation (which he refers to as the equity risk premium (ERP)).[47] In this paper, Dr. Damodaran discusses the results of Merrill Lynch from its monthly surveys of global institutional investors:

[45] John R. Graham and Campbell R Harvey, "The Equity Risk Premium in 2015" (October 1, 2015). Available at SSRN: https://ssrn.com/abstract=2611793 at 7 (Table 1); and, Pablo Fernandez, Alberto Ortiz Pizzaro, and Isabel Fernandez Acin, "Discount Rate (Risk-Free Rate and Market Risk Premium) Used for 41 Countries in 2015: A Survey" (October 17, 2017). Available at SSRN: https://ssrn.com/abstract=2598104 at 3 (Table 2 – Market Risk Premium) and 4 (Table 3 – Risk Free Rate).
[46] Aswath Damodaran, "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2021 Edition" (March 23, 2021). Available at SSRN: https://ssrn.com/abstract=3825823, at 91-92.
[47] Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2013 Edition," Aswath Damodaran, Stern School of Business, New York University. This article is appended as Attachment BE to this evidence.

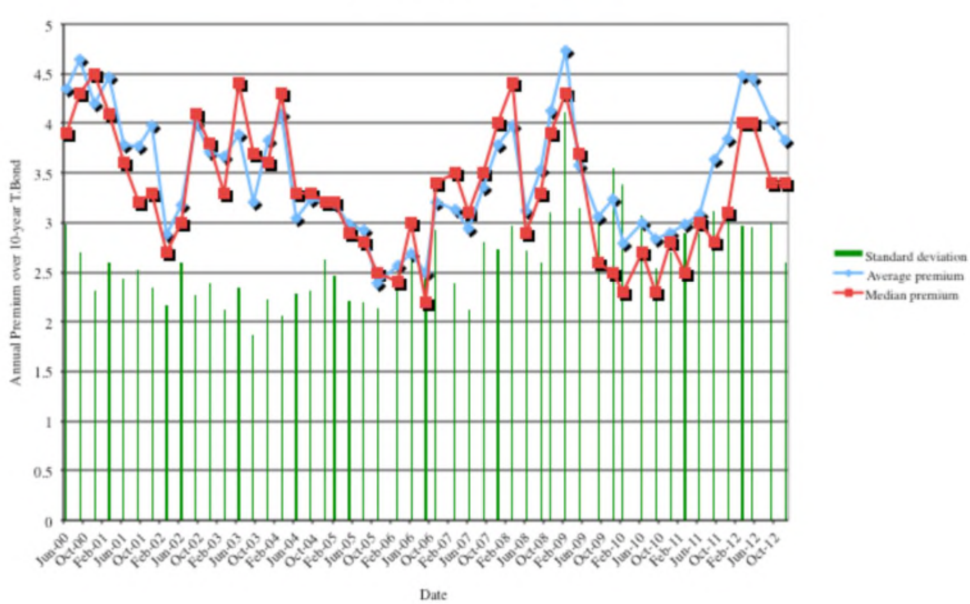
> Merrill Lynch, in its monthly survey of institutional investors globally, explicitly poses the question about equity risk premiums to these investors. In its February 2007 report, for instance, Merrill reported an average equity risk premium of 3.5% from the survey, but that number jumped to 4.1% by March, after a market downturn. As markets settled down in 2009, the survey premium has also settled back to 3.76% in January 2010. Through much of 2010, the survey premium stayed in a tight range (3.85% - 3.90%) but the premium climbed to 4.08% in the January 2012 update.[48]

This evidence verifies that finance professionals believe that MRPs lie within the 3-6% range (or, more aptly, the 3-4.5% range), and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

Dr. Damodaran then proceeds to discuss the results of Graham and Harvey (2013)'s surveys of CFOs regarding MRPs:

> To get a sense of how these assessed equity risk premiums have behaved over time, we have graphed the average and median values of the premium and the cross sectional standard deviation in the estimates in each CFO survey, from 2001 to 2012, in Figure 2.

Figure 2: CFO Survey Premiums



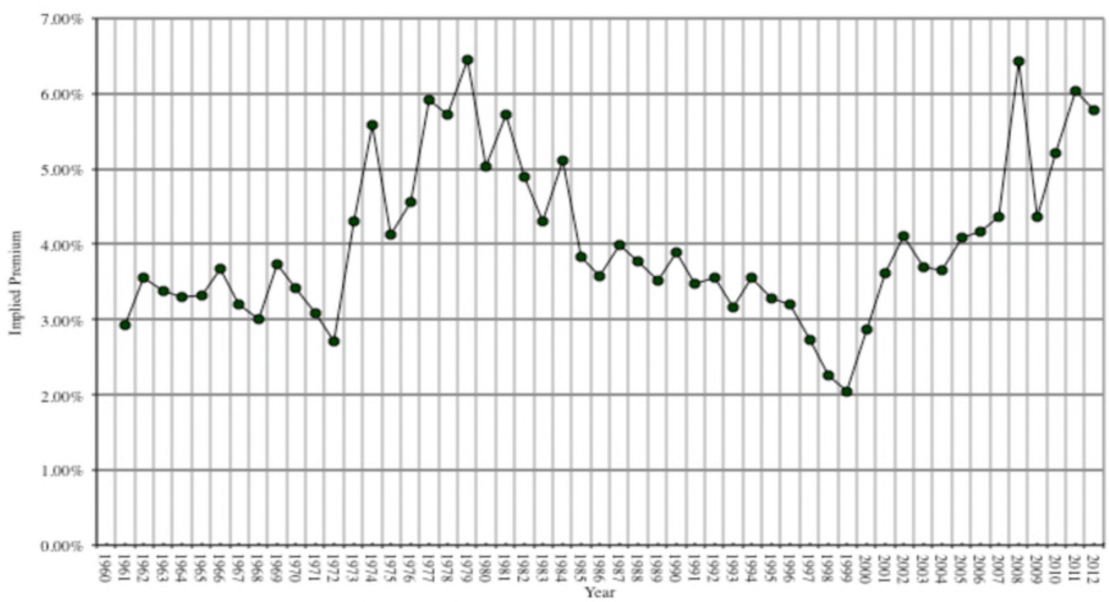
[48] *Ibid.*, pages 18-19.

> Note the survey premium peak was in February 2009, right after the crisis, at 4.74% and had its lowest recording (2.47%) in September 2006. The average across all 13 years of surveys (about 9000 responses) was 3.53%.[49]

This evidence also verifies that finance professionals believe that MRPs lie within the 3-6% range (or , more aptly, in the 2.47-4.74% range) over the 2000-2012 period, and that the MRP increases during periods of uncertainty, and declines during periods of less uncertainty.

Dr. Damodaran also discusses the implied MRPs in the S&P 500 Index from 1960-2012 and produces Figure 9, below:[50]

Figure 9: Implied Premium for US Equity Market



This evidence also shows that implied MRPs generally lie within the 3-6% range (and in fact are never less than 2% or above 6.5%), and that the MRP increases during periods of uncertainty (e.g., 1979 and 2008), and declines during periods of less uncertainty (e.g., the boom in stock markets at the end of the 1990s).

[49] *Ibid.*, pages 20-21.
[50] *Ibid.*, page 74.

Dr. Damodaran discusses his own approach to estimating and using MRPs when valuing companies, stating:

> On a personal note, I believe that the very act of valuing companies requires taking a stand on the appropriate equity risk premium to use. For many years prior to September 2008, I used 4% as my mature market equity risk premium when valuing companies, and assumed that mean reversion to this number (the average implied premium over time) would occur quickly and deviations from the number would be small. Though mean reversion is a powerful force, I think that the banking and financial crisis of 2008 has created a new reality, i.e., that equity risk premiums can change quickly and by large amounts even in mature equity markets. Consequently, I have forsaken my practice of staying with a fixed equity risk premium for mature markets, and I now vary it year-to-year, and even on an intra-year basis, if conditions warrant. After the crisis, in the first half of 2009, I used equity risk premiums of 6% for mature markets in my valuations. As risk premiums came down in 2009, I moved back to using a 4.5% equity risk premium for mature markets in 2010. With the increase in implied premiums at the start of 2011, my valuations for the year were based upon an equity risk premium of 5% for mature markets and I increased that number to 6% for 2012. In 2013, I will be using a slightly lower equity risk premium (5.80%), reflecting the drop from 2012.[51]

This evidence verifies that a well-respected finance professional, textbook author, and provider of financial data uses MRPs in the 4-6% range and varies his choice of MRP so that it increases during periods of uncertainty, and declines during periods of less uncertainty.

The results of a 2013 survey by Graham and Harvey was discussed above by Dr. Damodaran.[52] I would also note the following conclusions Dr. Graham and Dr. Harvey reached based on their ongoing surveys of CFOs:

> …the CFOs believe that the "risk premium" is a longer-term measure of expected excess returns and best covered by our question on the expected excess return over the next ten years – rather than the one-year question. Three-fourths of the interviewees use a form of the Capital Asset Pricing Model (which is consistent with the evidence in Graham and Harvey, 2001). They use a measure of the risk premium in their implementation of the CAPM.[53]

These conclusions are consistent with the long-term (with adjustments) approach to estimating

---

[51] *Ibid.,* page 79.
[52] "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. "The Equity Risk Premium in 2013," John Graham and Campbell Harvey, Fuqua School of Business, Duke University. This survey is appended to this evidence as Attachment BF.
[53] *Ibid.,* page 8.

the MRP that I advocate. It also shows that 3/4th of CFOs use some version of the CAPM. Further, Dr. Graham and Dr. Harvey examine the relationship between MRPs and two other common measures of risk aversion that I have referenced previously – the VIX and yield spreads:

> Finally, we consider two measures of risk and the risk premium. Figure 5 shows that over our sample there is evidence of a strong positive correlation between market volatility and the long-term risk premium. We use a five-day moving average of the implied volatility on the S&P index option (VIX) as our volatility proxy. The correlation between the risk premium and volatility is 0.52. If the closing day of the survey is used, the correlation is roughly the same. Asset pricing theory suggests that there is a positive relation between risk and expected return. While our volatility proxy doesn't match the horizon of the risk premium, the evidence, nevertheless, is suggestive of a positive relation. Figure 5 also highlights a strong recent divergence between the risk premium and the VIX.
>
> We also consider an alternative risk measure, the credit spread. We look at the correlation between Moody's Baa rated bond yields less the 10-year Treasury bond yield and the risk premium. Figure 6 shows a highly significant relation between the time-series with a correlation of 0.54.[54]

This evidence confirms that MRPs tend to increase as risk aversion increases, and decrease as risk aversion declines, which is consistent with my approach to estimating MRPs.

5.2.4 Estimating Beta

We now require a beta estimate to apply the CAPM, and my approach is justified based on the extensive empirical analysis and discussion regarding estimating beta that is provided in Appendix C of my evidence. In particular, the examination of the historical evidence in Appendix C confirms the following three important facts:

1. Canadian utility beta estimates have averaged somewhere between 0.20 and 0.40 – with **0.35** representing the best estimate.
2. Canadian utility beta estimates have never come close to one, with maximum values in the 0.6-0.8 range. Neither have U.S. utility beta estimates ever come close to one for that matter. Hence **the use of traditional adjusted betas is totally inappropriate.**

[54] *Ibid.*, pages 14-15.

3. **U.S. utility beta estimates are significantly higher than those for Canadian utilities, and should not be considered**.[55] This is consistent with the higher level of business risk associated with U.S. utilities.

Based on these observations, I recommend the following approach for determining reasonable beta estimates, which can be used by Canadian regulatory bodies such as the OEB when they receive a wide spread in beta estimates:

1. Ensure beta estimates are from reasonable comparators – i.e., **exclude U.S. utility beta estimates**.
2. **Do not use traditional "adjusted beta" estimates,** which are based on the inaccurate assumption that utility betas gravitate towards one in the long run.[56] If there is a desire or need for a "mechanical approach" to adjusting current beta estimates, simply adjust them toward the long-term average of 0.35, or even 0.45, rather than toward 1.0, as is done with published betas provided by services such as Bloomberg and Value Line.
3. Based on historical evidence, establish a range of reasonable beta estimates with a lower bound of 0.30 and an upper bound of 0.60.
4. After collecting and considering as much evidence as possible, and given the constraints (i.e., permissible range) discussed in #3 above, make a simple judgment based on current beta estimates.

As noted above, a review of the 2018 Alberta GCOC utilities' experts' evidence showed that Canadian utility beta estimates have averaged somewhere between 0.20 and 0.40 – with 0.35 representing the best estimate. In the 2018 Alberta GCOC Decision, the AUC calculated a historical utility beta average of 0.47, based on data that excludes the 1998-2007 period, in order to discard the abnormally low estimates obtained over the 1998-2002 period. It is important to recognize that as an average, this implies approximately half of the estimates would be both below and above this estimate of central tendency. The fact that this average is

[55] For example, Appendix C shows that Mr. Hevert's historical average Canadian beta estimates of 0.34 (monthly) and 0.38 (weekly) are just over half their U.S. counterpart estimates of 0.61 (monthly) and 0.72 (weekly), after accounting for leverage differences. The implied "unlevered" U.S. betas (0.234 monthly; 0.278 weekly) are almost double those for the Canadian utilities (0.131 monthly; 0.140 weekly).

[56] This is consistent with the approach used by LEI in its evidence, with final beta estimates determined based on raw beta estimates.

so close to the 0.45 that I have used in previous proceedings confirms the appropriateness of the range that I used and the judgment I employed in determining my beta estimate during the 2013, 2016, 2018, 2021 and 2023 Alberta GCOC Proceedings, and which lies at the mid-point of the range of reasonable beta estimates that I have previously recommended to that Commission during those proceedings.

The top portion of Table 8 provides both weekly and monthly beta estimates for the Canadian utility sample as of December 31, 2023, as well as the seven-year average of beta estimates over the 2016-2023 period.[57] The December 31, 2023 weekly beta estimate average is **0.668**, while the average for monthly betas is **0.582**, both of which are well above the long-term average beta estimate of 0.35 discussed above, and also the 0.45 beta estimate I have used during previous proceedings. The seven-year average weekly betas for the Canadian sample is **0.658**, while the seven-year average monthly beta estimate is **0.513** – with both estimates lying well above the historical average of 0.35. The average of all four beta estimates provided for this sample is **0.60**, well above the long-term average beta estimate of 0.35, and my usual beta estimate of 0.45, which lies slightly above the mid-point of these two figures. In my 2023 Alberta GCOC evidence, I obtained the same beta estimates using December 31, 2022 available Bloomberg data, and the average of the four averages at that time was 0.355, well below the average of 0.60 using December 2023 data. This illustrates that beta "estimates" for companies can change dramatically through time, and therefore why it is appropriate to reference long-term averages and use judgment since beta estimates at any given point in time based on historical data may not represent the best estimates of "future" betas, which is of course what we are trying to estimate. I would further note that during 2023, I continued to use my estimate of 0.45, rather than adjust it downwards based on the average estimate of 0.355, and despite the fact this was almost identical to the long-term average Canadian utility beta estimate. Therefore, I would judge my 0.45 estimate be a conservative and appropriate beta estimate for low-risk regulated operating utilities.

[57] The working papers for Table 8 are appended as Attachment I to my evidence.

TABLE 8

BETA ESTIMATES – December 31, 2023

Firm				
	Weekly Betas		**Monthly Betas**	
CANADIAN SAMPLE	**Dec 31 / 23**	**2017-2023 Average**	**Dec 31 / 23**	**2017-2023 Average**
Algonquin Power & Utilities Corp.	0.847	0.725	0.643	0.567
Canadian Utilities Ltd.	0.637	0.719	0.748	0.678
Emera Incorporated	0.655	0.624	0.535	0.463
Fortis Inc.	0.593	0.655	0.457	0.394
Hydro One Ltd.	0.607	0.568	0.526	0.465
Average	**0.668**	**0.658**	**0.582**	**0.513**
	Weekly Betas		**Monthly Betas**	
US SAMPLE	**Dec 31 / 23**	**2016-2023 Average**	**Dec 31 / 23**	**2016-2023 Average**
ALLETE	0.737	0.770	0.834	0.652
Alliant Energy Corporation	0.718	0.718	0.702	0.592
Ameren Corporation	0.721	0.677	0.638	0.554
American Electric Power Company, Inc.	0.674	0.693	0.670	0.520
Atmos Energy	0.753	0.706	0.778	0.595
Black Hills	0.831	0.799	0.773	0.641
CMS Energy Corporation	0.701	0.681	0.593	0.468
CenterPoint Energy	0.770	0.883	0.966	0.826
DTE Energy Company	0.701	0.742	0.777	0.642
Dominion Energy, Inc.	0.698	0.648	0.724	0.568
Duke Energy Corporation	0.677	0.662	0.647	0.501
Entergy Corporation	0.755	0.772	0.802	0.679
Evergy Inc.	0.700	0.686	0.703	0.592
Eversource Energy	0.756	0.743	0.730	0.578
MGE Energy Inc.	0.677	0.654	0.811	0.669
New Jersey Resources Corporation	0.742	0.760	0.773	0.669
NiSource Inc.	0.768	0.721	0.666	0.547
NorthWestern Corporation	0.677	0.772	0.648	0.583
Northwest Natural Holding Company	0.623	0.651	0.710	0.628
OGE Energy	0.744	0.826	0.814	0.777
ONE Gas Inc.	0.627	0.704	0.771	0.606

Portland General Electric Company	0.698	0.698	0.736	0.586
Sempra Energy	0.753	0.766	0.826	0.740
Southern Company	0.669	0.713	0.685	0.552
Spire, Inc.	0.746	0.716	0.689	0.542
Unitil Corporation	0.628	0.701	0.714	0.557
WEC Energy Group	0.669	0.664	0.616	0.466
Xcel Energy Inc.	0.678	0.674	0.614	0.517
Average	**0.710**	**0.721**	**0.729**	**0.602**

Source: Bloomberg, June 2024. Refer to Attachment I.

The bottom portion of Table 8 provides both weekly and monthly beta estimates for the U.S. utility sample as of December 31, 2023, as well as the seven-year average of beta estimates over the 2017-2023 period. The December 31, 2023 weekly beta estimate average is 0.710, while the average for monthly betas is 0.729, both of which are well above the 50-year average beta estimate of 0.55 determined by Sikes (2022) discussed above. The seven-year average weekly betas for the U.S sample is 0.721, while the seven-year average monthly beta estimate is 0.602 – with both being well above the historical average of 0.55 – as was the case with the Canadian beta estimates relative to their long-term average of 0.35. For the U.S. beta estimates in Table 8, the average of the four U.S. estimates is 0.69. In my 2023 Alberta GCOC evidence where I obtained the same estimates using December 2022 data, the average of the four averages was much lower at 0.50, as was the case with the Canadian utility beta estimates.

I would also note that the average of the four U.S. estimates in Table 9 of 0.69 is 15% higher than the Canadian average of 0.60. Not surprisingly based on my previous discussion, all four average U.S. utility beta estimates are higher than the Canadian estimates, and the average is higher than the Canadian average, as was also the case using December 2022 data, when all the estimates were lower for both categories of utilities. This confirms that U.S. utilities are riskier than Canadian utilities (even without taking into account the lower leverage of U.S. utilities). Based on this evidence and the longer term beta evidence discussed in Appendix C, I confirm that U.S. utilities are much riskier than Canadian utilities and should **not** be used as comparators for estimating Canadian utility betas.

As argued above, I will not consider the U.S. beta estimates, since I believe they are too risky to be legitimate comparators. Based on the evidence provided in Table 8 and combining it with long-term historical averages, it is obvious that a reasonable estimate of beta for a typical

Ontario utility should lie within the 0.30 to 0.60 range. The current average of Canadian beta estimates I note above is 0.60, which is well above the long-term average of 0.35. My recommendation is consistent with those I made in the 2013, 2016, 2018, 2021 and 2023 Alberta GCOC Proceedings, using the mid-point figure of my recommended range (i.e., 0.30-0.60) of **0.45** as my best point estimate, which is slightly above the mid-point of the long-term average of around 0.35, and is below the current average beta estimate of 0.60.

5.2.5 Final CAPM Estimates

While government bond yields have risen over the past few years, they still remain relatively low, both in absolute terms and by historical standards. A-rated Canadian utility bond yield spreads were sitting at 138 bp as of June 5, 2024, virtually identical to the long-term average spread of 140 bp. Generally, I adjust for any differences in this average yield spread based on research provided by analysts at the Bank of Canada that indicated that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian utilities.[58] Based on this this research, I subtract half of the "below average" yield spread (i.e., (0.138 - 0.140)/2), or -0.001%, from my CAPM estimate to account for this time varying risk premium.

Finally, I add 50 bp for financial flexibility (or flotation costs), consistent with previous OEB practice, and consistent with long-term estimates. Combining these items, I provide my CAPM estimates for the required equity return for the typical regulated Ontario utility, which are reported in the table below. Based on these calculations my CAPM analysis suggests an ROE of **6.05%**.

[58] Refer to: A. Garcia and J. Yang, "Understanding Corporate Bond Spreads Using Credit Default Swaps," Bank of Canada Review, Autumn 2009. This article is appended as Attachment AG to this evidence.

TABLE 9

CAPM ESTIMATES – 2024

Estimate	RF (%)	MRP (%)	Beta	Spread Adjust. (%)	Financial Flex. (%)	Ke (%)
CAPM Best Estimate	3.30	5.0	0.45	-0.001	0.50	**6.05%**

The CAPM parameters used (i.e., RF of 3.30%, MRP of 5% and a negligible spread adjustment of -0.001%) imply a required return on the entire market of 8.3%, well above the long-term market return expectations of finance professionals of 6.1% provided in Table 7, while in line with the long-term real returns on Canadian stocks. The implied required return on the entire market is also marginally above my best estimate of 7.5% for the long-term expected return on the market as I discussed previously.

5.3 Discounted Cash Flow (DCF) Estimates

5.3.1 DCF Model Overview

I use two approaches to apply the DCF model to estimate the appropriate ROE for regulated Ontario utilities using data as at the end of 2023 to:

1. find the implied rate of return for the overall market, which should be significantly higher than that for the average utility company which is much less risky than the average company in the market (and which serves as a useful upper bound for utility Ke estimates); and,
2. apply the models at the industry level using numbers that are representative of a typical publicly-traded utility company in Canada.

The model requires start of period market data and is based on estimating cash flows from now to infinity.

The Dividend Discount Model (DDM) is a commonly used DCF model that assumes common shares can be valued according to the present value of their expected future cash flows, as represented by dividends. The constant-growth (or single-stage growth) version of the DDM is a simplification of the broader model that holds if we assume that the growth in dividends (and earnings) is expected to occur at the same annual rate indefinitely (i.e., to infinity). The constant-growth model can be represented as:

$$\text{Price} = D_0(1 + g) / (Ke - g) = D_1/(Ke - g)$$

Where,

Price is the firm's most recent common share market price

D_0 represents the dividends paid over the most recent 12-month period

g represents the expected long-term average growth rate in dividends and earnings

Ke represents the required returns by a firm's common shareholders.

The single-stage DDM is convenient in the sense that it can be easily arranged to solve for the implied rate of return on common shares, as follows if we know their current price and dividends, and can estimate a long-term consistent growth rate:

$$Ke = (D_0/\text{Price})\times(1 + g) + g$$

5.3.2 Market DCF Estimates

Table 1 showed that real GDP growth has averaged 2.3% over the 1992 to 2022 period, which provides one potential estimate of long-term growth that could be used in the single-stage model, since one might expect long-term growth for the overall market to gravitate towards this figure. Similar assumptions are commonly made by financial analysts. The average forecast for real GDP growth for Canada for 2024 provided in Table 3 was 1.1%, which is below the 1.5% forecast from the Bank of Canada in its April 2024 MPR, so the mid-point of these two figures for 2024 growth is 1.3%. The Bank further predicted 2.2% real GDP growth for 2025, which is again higher than the average forecast of 1.9% from other financial organizations – so the mid-point of these estimates is 2.05% or 2.1%. The average of these three future estimates of real growth is 1.9%, which provides another reasonable estimate of future Canadian economic growth. Of course, we are trying to estimate a "nominal" required rate of return, so we should use nominal GDP growth as "g." We can estimate nominal growth rates by applying the 2% Bank of Canada inflation target, which generates the following long-term nominal Canadian GDP growth rate estimates that correspond to three real growth rates noted above: 4.3%, 3.3% and 4.1% - where 3.9% represents the average of these figures. These growth rates are in line with those used by security analysts when they use single-stage growth models to value securities (i.e., they usually use numbers in the 3-5% range when they use single period models).

The dividend yield for the S&P/TSX Composite Index as of December 31, 2023 was 3.19%. This is the "lagged" dividend yield (i.e., D0/Price) since it is estimated using dividends over the most recent 12-month period. Substituting the average nominal GDP growth estimate of 3.9% noted above into the single-stage DDM equation provided above, we get the following estimate for the implied equity return for the market as a whole for 2024:

$$Ke = (0.0319)\times(1.039) + .039 = 0.0721 \text{ or } \mathbf{7.21\%}$$

Despite the limitations of the model, and with the simplifying assumption of constant growth indefinitely, this estimate seems to be reasonable. It is only slightly below my long-term forecast for expected market returns of 7.5%, but is well above the average forecast for future Canadian stock market returns of 6.1% found in Table 7.

We can overcome one limitation of the single-stage growth model by using a variation of the DDM, called the H-Model. The H-Model is a multi-stage growth version of the DDM. It assumes that growth in dividends moves in linear fashion from some current short-term growth rate (defined as g_S) toward some long-term growth rate (defined as g_L) over a specified period of time, defined as 2H, where H is hence defined as the "half-life." It also offers the advantage that, similar to the single-stage DDM, it can be rearranged to determine a finite solution for Ke, which is shown below:

$$Ke = (D_0/Price)\times[(1 + g_L) + H(g_S - g_L)] + g_L$$

The average of the 2024 and 2025 real GDP growth forecasts of 1.3% and 2.1% respectively is 1.7%, which can be translated into a 3.7% nominal GDP growth rate. I will use this as my short-term growth rate (g_S), and I will use the historical long-term GDP nominal growth rate average of 4.3% as the long-term growth rate (g_L). Assuming it takes four years to get back to this long-term expected growth rate, then we would use H = 2, which provides an estimate for Ke of **7.59%.**

Combining the results from the two DDM models, we get estimates for Ke for the market in the 7.21-7.59% range. Taking the mid-point of these two estimates, we arrive at **7.40%** as my best estimate of the implied return on the market using DCF models, which is virtually identical to my 7.5% estimate for future market returns. DCF models will work better in aggregate than for Canadian utilities, which leaves us with the issue of how to adjust these figures into a reasonable implied return for utilities that possess considerably less risk than the average company in the market. At minimum, we could say that the market DCF estimates suggest that utility returns should be ***lower than 7.40%***.

5.3.3 Ontario Utility DCF Estimates

I will now apply both of the DCF models discussed above to the utilities' samples. Of course, determining the inputs here is somewhat trickier than for the broad market. A common way of estimating the growth rate for companies is to determine the company's **sustainable growth rate,** which can be estimated by multiplying the earnings retention ratio (which equals "1 – dividend payout ratio") by the ROE, as shown below:

g = (1 – payout ratio) × ROE.

The intuition behind the use of this formula is that growth in earnings (and dividends) will be positively related to the proportion of each dollar of earnings reinvested in the company multiplied by the return earned on those reinvested funds, which can be measured using ROE. For example, a firm that retains all its earnings and earns 8% on its equity would see its equity base grow by 8 percent per year. If the same firm paid out all of its earnings, it would not grow. It should work quite well for utility firms that pay a significant proportion of their earnings out as dividends, and that possess relatively stable ROE figures that are generally close to allowed ROEs, which do not usually fluctuate by large amounts.

Estimating future earnings growth rates using the sustainable growth rate represents an approach that is included in the CFA curriculum and in numerous academic textbooks, and is widely used in practice. In contrast, relying upon sell-side analyst growth estimates in DCF models, which are known to be overly optimistic, will lead to invalid estimates of Ke when using DCF models. For example, a study by Easton and Sommers[59] estimates the "optimism" bias in analysts' growth forecasts inflates final DCF cost of equity estimates by an average of 2.84%.

The use of these overly optimistic growth forecasts often leads to adopting growth rates for utility earnings and dividends that exceed expected growth in the economy (i.e., nominal GDP

[59] Source: Easton, Peter D., and Gregory A. Sommers. "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts." Journal of Accounting Research 45 no. 5 (December 2007), pp. 983-1016. This article is appended to my evidence as Attachment BG.

growth), which is simply not realistic for mature, stable operating utilities operating within a defined region. Appendix D provides greater details regarding these matters.

Table 10 below includes summary statistics on dividend yield, payout ratios and ROE for both the Canadian and U.S. utility samples that were included in Table 8. This data can then be used to estimate sustainable growth rates for the utilities, and ultimately the implied required rate of return using my two DCF models. Panel A reports the average, median, maximum and minimum figures for the Canadian sample for the December 2023 dividend yield (DY), the 2017-2023 average DY, the 2023 and 2017-23 average payout ratios[60], and the 2023 and 2017-2023 average for ROEs. Panel B reports the same statistics for the U.S. sample. The working papers for Table 10 (and Table 11) are appended to my evidence as Attachment J.

The summary statistics included in Panel A of Table 10 appear reasonable for a typical regulated and publicly-traded Canadian utility in several regards. High dividend yields averaging in the 4-5% range and corresponding high payout ratios averaging in the 77-79% range are in line with historical figures, and are consistent with the high dividend paying nature of such profitable, slow growing firms. The ROE averages in the 7.8-8.5% range are also reasonable. The statistics for the U.S. sample included in Panel B are also reasonable; although it is noteworthy that dividend yields around 3.9% and corresponding payout ratios in the 67-68% range are well below the corresponding figures for Canadian utilities, indicating U.S. firms are priced higher and maintain lower dividend payouts than Canadian utilities. The U.S. sample ROE averages in the 9.4-9.6% range are higher than those for the Canadian sample, which is consistent with the observation that allowed ROEs are generally higher in the U.S. than in Canada.

[60] Payout ratios were "capped" at 100% to control the influence of extreme payouts on averages - this process obviously had no effect on the reported medians.

TABLE 10

DCF INPUT ESTIMATES – 2017-2023 FIGURES

Panel A (Canadian Sample)	DY (Dec 23)	2017-2023 Avg DY	2023 Payout	2017-2023 Avg Payout	2023 ROE	2017-2023 Avg ROE
Average	5.06	4.53	78.67	77.29	7.76	8.51
Median	5.71	4.77	77.01	79.33	9.44	7.06
Max	6.55	5.57	100.00	88.69	11.80	12.30
Min	2.96	3.55	64.57	62.60	0.41	6.67
Panel B (U.S. Sample)						
Average	3.94	3.47	68.27	67.12	9.40	9.59
Median	3.95	3.34	65.11	67.18	9.25	9.91
Max	5.38	6.05	100.00	69.71	17.08	10.60
Min	2.16	2.06	48.25	63.81	-2.98	7.22

Data Source: Morningstar at www.morningstar.ca.

It is difficult to find "typical" or representative Canadian regulated publicly-traded utilities. However, using averages and medians (which offset to some extent the influence of extreme observations) provides a useful starting point. Columns 2 and 3 of Table 11 provide estimates of sustainable growth rates (g) using the ROE and payout averages and medians reported in Table 10. These are calculated using the formula above (i.e., g = (1 – payout) × ROE)). Column 2 uses the average and median figures for the 2023 ROE and payout figures, while column 3 uses the averages and medians for the 2017-23 ROEs and payout figures. The median and average growth rates range from 1.46% to 2.17%, with the average of the two averages being 1.79% and the average of the two medians sitting at 1.82%. The mid-point of these two estimates is 1.80%. This seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth in the 3.3-4.3% range discussed previously. The averages of the average and median growth rates for the U.S. sample are higher at 3.07% and 3.24% respectively, reflecting both the lower payout ratios and the higher ROEs of U.S. utilities.

It is important to recognize with respect to growth rates used in DDM estimates that the long-term growth rate of nominal GDP should be viewed as a "ceiling" for long-term rates used in this model, as I have argued previously. For example, the AUC noted in the 2018 Alberta GCOC Decision (bold added for emphasis) that:

> The Commission recognizes that the utilities are, as Dr. Cleary stated in his evidence, 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**.[61]

Further, even the assumption of nominal GDP growth (i.e., average growth) estimated previously as 3.3-4.3% is an ambitious target for regulated utilities that operate virtual monopolies in mature markets, with little opportunity for dramatic growth, as also acknowledged previously by the AUC, in the 2013 GCOC Decision:

> However, the Commission is also mindful that, as both experts acknowledged, **the GDP growth rate may be an ambitious target** for long-run earnings growth in respect of low-risk, mature, utilities.[62]

In other words, **growth estimates that exceed GDP growth should not be used in constant-growth versions of DCF models**. Given the upward bias of **analyst growth estimates** noted above and discussed in detail in Appendix D, they **should not be used** – either in constant-growth DCF models or in multi-stage DCF models. I note that LEI uses analyst forecasts provided by S&P Capital IQ in their single-stage DCF estimates that produce average growth forecasts of 10.26%, 6.41% and 6.34% for their Generation, Electricity T&D, and Gas Distribution proxy groups respectively, which leads to ROE estimates of 11.52%, 10.53% and 10.56% respectively.[63] These growth rates **greatly exceed my estimate of future nominal GDP growth of 3.3-4.3%**, which is based on both expert forecasts and historical data. As such, the LEI DCF estimates should be disregarded, as in fact LEI did when obtaining its final base ROE estimate, which it based on its CAPM estimate.

[61] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 92, para. 438.
[62] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 190 [emphasis added] [footnote omitted].
[63] Individual company growth estimates were as high as 15.3%, which is clearly an even more unreasonable long-term growth expectation.

TABLE 11

DCF GROWTH AND SINGLE STAGE DDM ESTIMATES

1	2	3	4	5
	Implied g (2023)	**Implied g (17-23)**	**Implied Ke (2023 g and 2023 DY)**	**Implied Ke (17-23 g and 7-year DY)**
PANEL A: Canadian Sample				
Average	1.65	1.93	6.80	6.55
Median	2.17	1.46	8.00	6.30
Average of 2 averages g = 1.79%			**Average of 2 averages Ke = 6.68%**	
Average of 2 medians g = 1.82%			**Average of 2 medians Ke = 7.15%**	
PANEL B: U.S.				
Average	2.98	3.15	7.05	6.73
Median	3.23	3.25	7.30	6.70
Average of 2 averages g = 3.07%				**Average of 2 averages Ke = 6.89%**
Average of 2 medians g = 3.24%				**Average of 2 medians Ke = 7.00%**

The final two columns in Table 11 report the Ke estimates that are derived using the single-stage DDM and inputting the appropriate growth estimates from column 2 or 3 along with the corresponding dividend yield (reported in Table 10). Recall this formula can be represented as follows when we begin with the dividend yield based on dividends over the previous 12 months: $Ke = (D_0/Price)\times(1 + g) + g$.

The Canadian sample Ke estimates lie in a range from 6.30% to 8.00%. The average of the two Ke estimates determined using averages is 6.68%, while the average of the two medians is 7.15%. I will assign a best estimate single-stage DDM estimate at the mid-point of these two figures at **6.91%**, which is only 30bp below my 7.21% single-stage growth DDM estimate for the market, which can be considered high since regulated utilities are considerably less risky than the average company. If we add 50 basis points for flotation costs, we end up with a best estimate of **7.41%**. While I do not use the U.S. Ke estimates, the overall average would be

6.95% (before flotation costs adjustments), so virtually identical to my 6.91% estimate for the Canadian sample.

Similar to the approach used above to estimate Ke for the market, I will now apply the H-Model to estimate the implied rate of return for a typical Canadian utility. This model requires two growth estimates – the short-term rate (g_S), and the long-term rate (g_L). I will denote g_S as the mid-point of the implied growth rates determined using 2023 payout ratios and ROEs, which are reported in column 2 of Table 11. I then denote as g_L the mid-point of the implied growth rates using long-term averages for payout and ROE, which are reported in column 3 of Table 11. The underlying rationale is that growth rates estimated over a longer period of time are more representative of those that can be expected in the long run. The results of this analysis are reported in Table 12 below. The working papers for Table 12 are appended to my evidence as Attachment K.

TABLE 12

H-MODEL ESTIMATES

Canadian Sample		
	H=2	**H=1**
Current D0/P0	0.0506	0.0506
gs (current sustainable g)	0.0191	0.0191
gL (long-term sustainable g)	0.0170	0.0170
H = 2 or 1 (i.e., 4-year (or 2-year) transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0191	0.0191
g1	0.0186	0.0180
g2	0.0180	0.0170
g3	0.0175	0.0170
g4	0.0170	0.0170
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0687**	**0.0688**
AVERAGE	**0.0688**	
U.S. Sample		
Current D0/P0	0.0394	0.0394
gs (current sustainable g)	0.0311	0.0311
gL (long-term sustainable g)	0.0320	0.0320
H = 2 (i.e., 4-year (or 2-year) transition from gs to gL)	2.0000	1.0000
Growth Pattern Under Assumptions		
g0	0.0311	0.0311
g1	0.0313	0.0315
g2	0.0315	0.0320
g3	0.0318	0.0320
g4	0.0320	0.0320
k = (D0/P0)*[(1+gL)+H(gs-gL)]+gL	**0.0726**	**0.0727**
AVERAGE	**0.0727**	

As before, I will use only my Canadian sample estimates for Ke, for the reasons discussed above. The Ke estimates for the Canadian sample are 6.87% and 6.88%, with a mid-point of 6.88%. Combining this mid-point with a 0.50% allowance for flotation costs, we get an H-model estimate of **7.38%**. The Ke estimates from the H-Model are virtually identical to the estimate derived using the single-stage model of 7.41% after including flotation costs of 0.5%.

By contrast, the U.S. H-model estimate of 7.27% is slightly above the U.S. single-stage estimate of 6.95%, reflecting a slightly higher long-term growth rate implied from the 2016-2023 U.S. data relative to 2023 implied growth rates.

My DCF analysis suggests a 7.4% required return on the market with a range of 7.21-7.59%. As discussed previously, this estimate is very close to my market return estimate of 7.5% and is well above current estimates of finance experts of 6.1%. For utilities, after including a 50 basis point flotation cost allowance, the results suggest a required return of 7.41% using the single-stage model, and 7.38% using the H-model. Weighting these two estimates equally gives me a final DCF estimate of **7.4%.** However, this estimate is only 0.5% below my DCF estimate for the market (if we also adjust the market estimates by adding 50 bp for flotation costs to the 7.4% DCF market estimate), so it seems slightly high for below-average risk utilities relative to overall expected market returns.

5.4 Bond Yield Plus Risk Premium (BYPRP) Estimates

The BYPRP approach adds a risk premium (generally in the 2-5% range) to the yield on a firm's outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium used in CAPM, which represents the premium above government risk-free yields and expected market stock returns. The BYPRP approach is depicted below:

Ke = Company's Bond Yield + Company Risk Premium

It is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts[64] and by over 50 percent of Canadian CFOs.[65]

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable ***market-determined*** bond yields, to estimate a required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return

[64] Model Selection from "Valuation Methods" Presentation, October 2007, produced by Tom Robinson, Ph.D., CFA, CPA, CFP®, Head, Educational Content, CFA Institute. Copyright 2007, CFA Institute. Appended to my evidence as Attachment AS.

[65] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" Multinational Finance Journal 15-3, 2011. Appended to my evidence as Attachment AU.

to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these required returns (i.e., the greater the risk premium).

This approach employs solid intuition. For one thing, it overcomes technical issues that arise when beta estimates are suspect due to extreme market movements, such as those observed during the early 2000s, or difficulties in estimating future growth rates in dividends and earnings. In fact, as a risk-based model, there is a relationship with the CAPM in several ways. For example, the firm's yield on outstanding debt will be related to RF, as well as to yield spreads which will vary with market conditions, just as the MRP does in the CAPM. Also, we can "adjust" the risk premium applied to a particular firm according to its riskiness - one measure of which might be by making reference to its typical beta (i.e., lower company risk premiums should be used for firms with lower betas and vice-versa).

The first step in applying the BYPRP approach is to obtain an estimate of the cost of long-term yields on a typical utility. As of June 5, 2024 the yield on long-term A-rated Canadian utility bonds was 4.68% according to the Bloomberg data used to construct Figure 3. This figure is close to the average yield of 4.78% on bonds outstanding for five Canadian utilities, as provided below. For example the following bid and ask yields were observed as of June 6, 2024 (according to Bloomberg):

Description	S&P	Fitch	DBRS	Moody's	Maturity Date	Bid Yield	Ask Yield	Mid-Point
Fortis Alberta Inc	A-		A(low)	Baa1u	Oct-52	4.761	4.68	4.7205
Fortis BC Inc			A(low)	Baa1	Jul-47	4.934	4.867	4.9005
CU Inc		A	A(high)		Nov-50	4.772	4.705	4.7385
Enbridge Gas Inc	A-		A		Nov-50	4.846	4.798	4.822
Hydro One Inc	A-		A(high)	A3	Dec-51	4.758	4.704	4.731
As of June 06, 2024					**Average**	4.8142	4.7508	**4.7825**

This evidence implies that 4.7% is a reasonable starting point for my BYPRP estimate.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of 2.5%.[66] Combining this information, I obtain the following estimate for Ke according to this approach:

Ke = 4.7 + 2.5 = **7.2%**

If we add 50 bp for flotation costs, we end up with a Ke estimate **7.7%**. This is on the high side given my market estimate of 8% (if we add 0.50% to my raw market estimate of 7.5%). It is also well above my CAPM estimate of 6.1% and 30 bp above my DCF estimate of 7.4%.

5.5 Price-to-Book Ratios and Equity Returns

Table 10 reported a 2023 average ROE for the 5 Canadian utilities in the Canadian sample of 7.76%, with a 2017-2023 average of 8.51%. These averages are well below the 2024 allowed ROE for regulated Ontario utilities of 9.21%. The allowed ROE is higher than those for the Canadian sample of publicly listed utilities; albeit most of those utilities are holding companies that hold assets in several jurisdictions that are riskier than Ontario, and most also hold unregulated assets. This indicates that 9.21% is a very healthy allowed ROE, considering that we know regulated operating Ontario utilities are much less risky than the average Canadian publicly listed utility company, which are holding companies. In fact, the allowed ROE of 9.21% is well above the required equity return estimates (after adding flotation costs) determined using the CAPM, DCF and BYPRP approaches, with best estimates of 6.05%, 7.4% and 7.7% respectively. All of this suggests that Ontario utilities (if publicly listed) would make attractive debt and equity investments based on their allowed ROEs and low risk profiles. Certainly, from an investor's point of view, low-risk utilities that have regulated returns based on their risk level are attractive. For example, assume an investor used CAPM to determine his required rate of return for an average regulated utility and arrived at the 6.05% figure that was determined above and the utility earned the currently allowed ROE of 9.21%. Of course, this does not mean that the actual return on the stock was 9.21%; however, there is an obvious relationship between the two. I examine this relationship below by reference to price-to-book (P/B) ratios and stock returns.

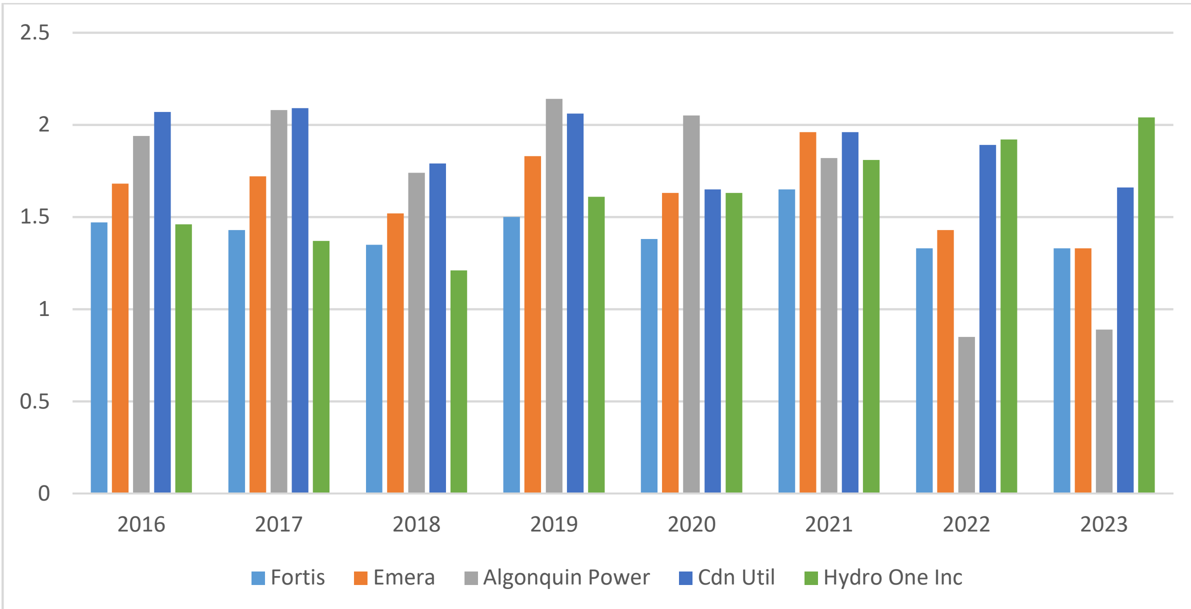
[66] For example, Attachment AH provides an example of implementing the BYPRP approach for IBM from the CFA curriculum, where a risk premium of 2.75% is added to cost of IBM's debt. Clearly IBM is riskier than a regulated A-rated utility, so 2.5% is very reasonable by comparison.

I begin by considering the P/B ratios over the 2017-2023 period for the Canadian and U.S. utility samples examined previously in the DCF analysis. The individual P/B ratios for the Canadian sample are presented in Panel A of Figure 13. It is obvious from the chart that almost all of the ratios are above one throughout the entire period, with the exception of the P/B ratio for Algonquin in 2022 and 2023. Panel B presents the P/B ratios for the U.S. sample over the same period, and none of the individual P/B ratios was ever less than one. Table 13 provides summary statistics for the two samples. Panel A shows that the average P/B ratio for Canada ranged between 1.45 and 1.84 over the period, averaging 1.65. Panel B shows that the average P/B ratio for the U.S. sample was greater than the Canadian average every year, ranging from 1.69 to 2.36 and averaging 2.05 over the 2017-2023 period. The working papers for Figure 13 and Table 13 have been appended to my evidence as Attachment L.

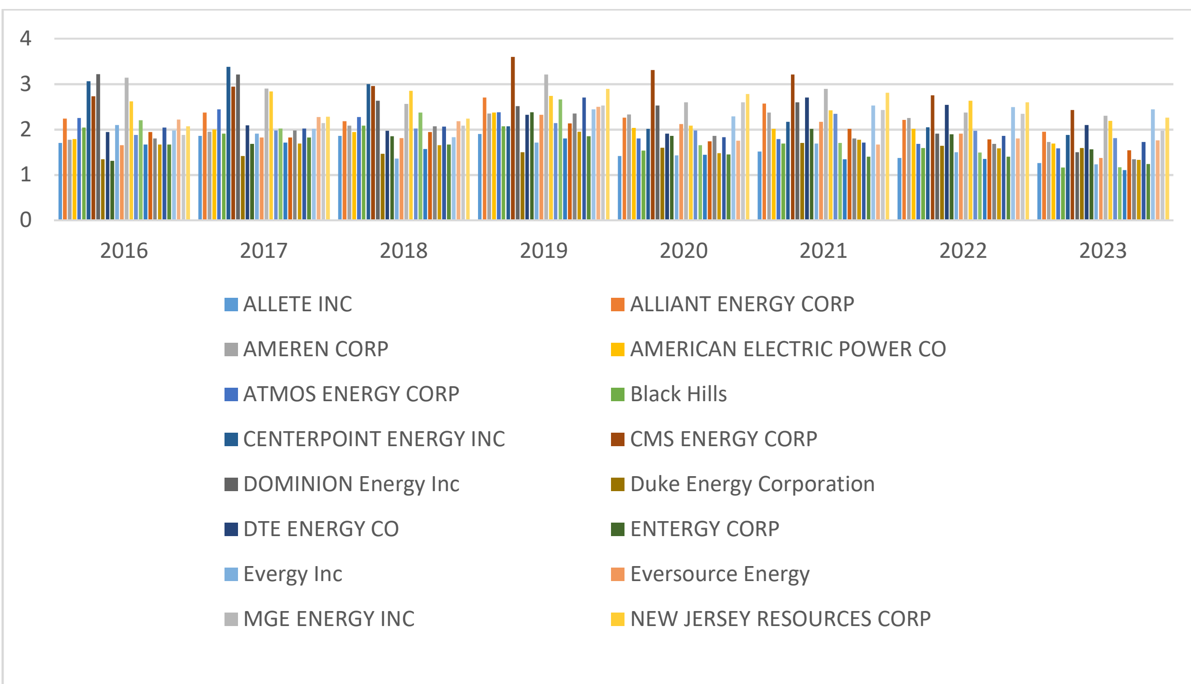
FIGURE 13

UTILITY P/B RATIOS – 2016-2023

Panel A: Canadian Sample



Panel B: U.S. Sample



Data Source: Morningstar at www.morningstar.ca.

TABLE 13

P/B RATIO SUMMARY STATISTICS (2017-2023)

Panel A: Canadian Sample

All Utilities	2017	2018	2019	2020	2021	2022	2023	2017-23 Average
Average	1.74	1.52	1.83	1.67	1.84	1.48	1.45	1.65
Median	1.72	1.52	1.83	1.63	1.82	1.43	1.33	1.61
Max	2.09	1.79	2.14	2.05	1.96	1.92	2.04	2.00
Min	1.37	1.21	1.50	1.38	1.65	0.85	0.89	1.26

Panel B: U.S. Sample

All Utilities	2017	2018	2019	2020	2021	2022	2023	2017-23 Avg
Average	2.16	2.09	2.36	1.99	2.11	1.95	1.69	2.05
Median	2.005	2.065	2.36	1.885	2.01	1.9	1.64	1.98
Max	3.38	3.00	3.6	3.31	3.21	2.75	2.44	3.10
Min	1.41	1.36	1.5	1.41	1.34	1.35	1.10	1.35

Data Source: Morningstar at www.morningstar.ca.

Generally speaking, higher P/B ratios indicate greater future growth opportunities, and firms that have P/B ratios greater than one are earning rates of return that are at least "fair," if not above fair. This is consistent with the AUC's statement in the 2011 Alberta GCOC Decision. The AUC confirmed the usefulness of P/B ratios in the 2013 Alberta GCOC Decision, noting:

> Overall, the Commission confirms its findings in Decision 2011-474 that an examination of a given company's P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility's awarded ROE to ensure that it is sufficiently able to attract investment in the capital markets at reasonable rates and maintain its financial integrity.[67]

The constant-growth DDM can actually be rearranged to show that the appropriate P/B ratio can be expressed as:[68] P/B = (ROE – g) / (Ke – g)

[67] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 221.
[68] This is true if we use the following sustainable growth rate for "g" in the DDM: g = (1 – payout) × ROE.

This expression implies that P/B ratios will be greater than one if actual ROE > Ke, will equal one if Ke = ROE, and will be less than one when ROE < Ke (which implies they are earning excess economic rent). This is all very intuitive – firms that earn a return on their equity above the cost of that equity will increase firm value. We can use the equation above to estimate the implied cost of equity (Ke) for given values for P/B, ROE and g. For the Canadian sample, we can examine the 2023 average ratio of 1.45 for P/B. I will use 1.80% as an estimate for "g" since it is the mid-point of the average of average growth rates of 1.79% and the average of median growth rates of 1.82% that were provided in Table 11. Calculations provided in Attachment L show that if we used the current allowed ROE of 9.21% for Ontario utilities as our ROE input, we would get an implied Ke figure of **6.81%.** If we instead used the average 2023 ROE of 7.76% for the Canadian sample as our ROE input (as per Table 10), we would get an implied Ke figure of **5.91%,** while if we used the 2017-23 average ROE of 8.51% (as per Table 10), the implied Ke would be **6.43%.** For the U.S. sample, we can use the 2023 average ratio of 1.69 for P/B and 3.15% for "g" (i.e., the mid-point of the average of average growth rates of 3.07% and the average of median growth rates of 3.24% that were provided in Table 11). If we used the current allowed ROE of 9.21% for Ontario utilities as our ROE input, we would get an implied Ke figure of **6.74%,** while if we used the average 2023 ROE of 9.40% for the U.S. sample, we would get an implied Ke figure of **6.50%,** while if we used the 2017-23 average ROE of 9.59%, the implied Ke would be **6.45%.**

Both the Canadian and U.S. implied Ke estimates above are very much in line with my final ROE estimate for Ontario utilities of **6.55%** (before adding 0.5% for flotation costs). While I do not assign any weight to this estimate for purposes of determining Ke, the bottom line of this analysis is that the P/B ratios for utilities reported above indicate that Ontario (and other Canadian) utilities appear to be earning a more than satisfactory ROE, and have done so for quite some time. This is important **market-based** information that supports my Ke estimates, and confirms that Canadian (and U.S.) utilities earn ROEs well in excess of their required equity return.

5.6 Summary of ROE Calculations

I have weighted all three of my Ke estimates equally, as I have done in all my previous evidence, because all three methods are used in practice and provide different perspectives on

Ke. As discussed previously, CAPM is more heavily relied upon in practice due to its conceptual advantages. For example, returning to the previous studies that were cited with respect to the DCF approaches to estimating Ke, they were used by:[69]

- only 15% of U.S. CFOs - versus over 70% for CAPM;[70]
- about 12% of Canadian CFOs - versus close to 40% for CAPM.[71]
- Not widely used by investors, while CAPM was used by the majority of investors.[72]

CAPM is also more intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, as discussed earlier.

I also give equal weighting to the BYPRP approach which is much more widely used than DCF approaches due to its intuitive nature, and because it adjusts for market-determined borrowing rates and risk. In fact the BYPRP approach is more widely used than CAPM by Canadian CFOs, as mentioned earlier. Thus the BYPRP approach accounts for interactions between company debt costs and equity markets, and as such it is intuitively sound.

Based on an equal weighting of the three approaches, I determine the following best estimate for allowed Ontario utility ROEs:

Ke = (1/3)(6.05) + (1/3)(7.4) + (1/3)(7.7) = **7.05%**

This estimate is very reasonable when compared to expected long-term overall stock market returns in the 4-9% range and a long-term expected market return of 7.5% (without any flotation charges added), when we consider the low-risk nature of regulated utilities. It is important to recognize that overall stock market conditions have changed over the last three

[69] DCF estimates of Ke were not used by any of the analysts in the Robinson (2007) survey, in which 68% used CAPM. This is because the focus was on which discount rate would be used "in" DCF models, so the use of a discount rate determined by such models would be inappropriate, since it lead to a "circular argument."

[70] Graham, John R., and Harvey, Campbell R. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics* 60 (2001), pp. 187–243.

[71] H. Kent Baker, Shantanu Dutta and Samir Saadi, ,"Corporate Financial Practices in Canada: Where Do We Stand" *Multinational Finance Journal* 15-3, 2011.

[72] J. B. Berk and J. H. van Binsbergen, 2017, "How Do Investors Compute the Discount Rate? They use the CAPM," *Financial Analysts Journal*, Vol. 73, No. 2: pp. 25–32.

decades and double digit “nominal” returns are no longer the norm for stocks, given existing 2% long-run inflation expectations. In other words, long-term nominal stock returns in the 4-9% range are consistent with current long-term forecasts by market professionals (which averaged 6.1%) and with historical long-term real stock returns.

6 CAPITAL STRUCTURE RECOMMENDATIONS

6.1 Enbridge Gas Inc. (EG)

My recommendation for the allowed equity ratio for EG remains at 36%, which was the recommendation provided in my evidence during the EG rebasing application in 2023, for the reasons and conclusions relied upon at that time, and based on the evidence I provided. I do acknowledge that the decision was made to increase EG's deemed equity ratio to 38%, primarily due to a perceived increase in energy transition risks. I do not believe this increase was necessary for the reasons noted in my 2023 evidence. In particular, EG continues to be able to attract debt capital at yields consistent with the A-rated utility yield index yields, and maintains debt ratings of: A(stable) from DBRS Morningstar; and, A-(stable) from S&P. Debt rating reports identified **low business risk** (S&P) or **low-risk regulated operations** (DBRS) as the #1 strength for EG; and, there was nothing in these reports to indicate that either rating agency was uncomfortable with EG's previously existing equity ratio of 36%. My analysis of credit metrics for EG further showed that at the previously existing equity ratio of 36% the credit metrics for EG were forecast to improve over the test period, and would in fact have exceeded the credit metric estimates used by S&P in determining its stable assessment for EG's rating. This analysis demonstrated that at a 36% equity level, the credit metrics thresholds were **more than adequate**. In short, there was no need for an increase in EG's equity ratio from 36% to maintain its current strong credit ratings (financial integrity), or its ability to continue to access capital at favorable rates. Therefore, I continue to maintain that 36% is an appropriate deemed equity ratio for EG, and I refer the reader to my 2023 evidence for a detailed analysis regarding this matter, which I do not repeat here.

6.2 Hydro One Inc. (Hydro One or HOI)

Given the importance of Hydro One Inc. to Ontario's electricity sector, accounting for well over 90% of transmission and over one third of all distribution (e.g., 35.6% as of 2020), I discuss Hydro One's equity thickness in this section of my evidence. I recommend **HOI's allowed equity ratio be reduced to 38%**, and that the OEB consider reducing it further to 36% (along with EG's equity ratio) over the following 2-3 years.

6.2.1 Credit Ratings

Recent debt rating reports identify **excellent business risk** and **very low industry risk** (S&P); as well as **reasonable regulatory support** (DBRS Morningstar (DBRS)) as strengths for HOI. This is consistent with HOI's regulated operations conducted in a well-defined and economically strong region with strong regulatory support, and where it can reasonably pass on legitimate costs to its customers.

Currently, HOI maintains the following long-term debt ratings: DBRS – A(high) – Stable; S&P – A(Stable)[73]; and, Moody's – A3. The DBRS rating has been the same for over 10 years, while the S&P rating of A- has been maintained since 2019 while the qualifier was upgraded to "positive" in August of 2023 and then the rating was upgraded to A in June 2024. Moody's rating of A3 has been maintained since 2019, and was confirmed in May of 2023. These high ratings are indicative of sound credit quality, and contribute to HOI's ability to issue debt at attractive rates (as will be discussed in Section 6.2.2).

Consider the following information obtained from HOI's DBRS debt rating report of November 20, 2023,[74] which confirmed its rating of **A and stable**. DBRS suggested that this rating reflected the following rationale (bold added for emphasis):

> **All trends are Stable**. The credit ratings of HOI are **based on its regulated electricity distribution and transmission operations** in the Province of Ontario (the Province or Ontario; 47.1%; rated AA (low) with a Positive trend by DBRS Morningstar), which **operates under a reasonable regulatory framework** by the Ontario Energy Board (OEB). The Stable trends **reflect the Company's financial risk assessment, with all key credit metrics in line with the "A" credit rating category**.

DBRS identifies the following strengths for EG (bold added for emphasis):

> 1. **Reasonable regulatory environment**
>
>   HOI's earnings are contributed by its **low-risk regulated transmission and distribution businesses** that operate under a **reasonable regulatory framework**. The regulatory regime under the OEB **permits the Company a reasonable**

[73] The S&P rating for HOI and Hydro One Ltd. were upgraded to A from A-(positive) as of June 10, 2024. See: Hydro One Ltd. Upgraded To 'A' On Improved Govern | S&P Global Ratings (spglobal.com).
[74] Appended to my evidence as Attachment BH.

> **opportunity to recover operating and capital costs and earn the approved rates of return**….
>
> **2. Extensive franchise area**
>
> HOI **owns the largest transmission and distribution businesses in Ontario**. The Company operates approximately **95% of the Province's transmission infrastructure**, based on revenues approved by the OEB, and is connected to 35 local distribution companies (including HOI's own distribution business) and 85 large, directly connected industrial customers…
>
> **3. Reasonable financial profile**
>
> HOI continues to maintain a reasonably healthy balance sheet, with **all key credit metrics reasonable for the current rating category** (debt-to-capital ratio at 55.6%, cash flow-to-debt at 14.1%, and EBIT interest coverage at 3.13 times (x) for the 12 months ended June 30, 2023 (LTM 2023))…

DBRS also notes the following potential challenges:

1. High level of planned capex
2. High dividend payout
3. Earnings sensitive to volume and costs

With respect to challenge #1, I would note that in the DBRS "Assessment of Regulatory Framework" summary provided on page 11 of the report it assesses "Capital and Operating Recovery Cost" as "Good" (the second highest category), and notes that:

> Major capital costs are preapproved by the OEB and added to the rate base after project completion. In addition, the OEB can approve rate riders to allow for the recovery or disposition of specific regulatory accounts over specified time frames.

Further, in its Investor Overview (Post first quarter 2024),[75] Hydro One Ltd. (HOL) notes on slide 15 of the presentation (entitled "Capital investment driving rate base growth") that its projected regulated capital investments will decline from \$3.09b in 2024 to \$2.39b by 2027. HOL also forecast that these capital investments will contribute to significant rate base growth with a cumulative average growth rate (CAGR) of approximately 6% over the 2022-27 period (with rate base increasing from \$23.6b in 2022 to \$31.8b by 2027). HOL is obviously

[75] Appended to my evidence as Attachment BI.

suggesting this a positive consideration, and it also forecasts that this will contribute to future growth in earnings, which HOL estimates will grow at a CAGR of 5-7% over the 2022-2027 period (as noted on slide 16 of the presentation).

Finally, on page 12 of its report DBRS states that there are no environmental, social or governance factors that "had a relevant or significant effect on the credit analysis."

As noted above, the S&P rating for HOI and HOL were upgraded to A from A-(positive) as of June 10, 2024. That update notes (bold added for emphasis) that:[76]

> We continue to assess **HOL's business risk profile as excellent**. Our assessment reflects the company's **low-risk regulated utility operations** that provide essential services in Ontario. Furthermore, **given HOL's monopoly and material barriers to entry, it is effectively insulated from pure-play competitive market challenges**. The company's business risk profile is bolstered by its **large footprint in Ontario**, which includes almost all (95%) of the province's transmission system and a large customer base of about 1.5 million electric distribution customers. We assess the utility as **operating under a supportive, generally transparent, consistent, and independently operated regulatory construct, which supports a stable and predictable cash flow model that minimizes its regulatory lag**.

6.2.2 The Cost of Debt for Hydro One Inc.

As of June 5, 2024 the yield for the long-term A-rated Canadian utility bond index was 4.68%, while the 30-year government of Canada bond yield was 3.30%. As reported in Section 5.4, at that time, the mid-point between bid and ask yields was 4.73% for HOI bonds maturing at 12/2051, which was the second lowest mid-point yield of the five utilities for which yields were reported (Fortis Alberta was slightly lower at 4.72%), and was below the five-utility average of 4.78%, as well as below that for EG of 4.82%. This indicates that the market-determined yield on HOI's long-term bonds was less than or equal to the average Canadian A-rated utility yield. In other words, HOI is able to attract debt capital at rates that correspond to those of similar low-risk entities. This provides support that HOI's current risk profile comfortably satisfies the third leg of the fair return standard. In other words, HOI's risk profile

[76] See: Hydro One Ltd. Upgraded To 'A' On Improved Govern | S&P Global Ratings (spglobal.com).

will "*permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (**the capital attraction standard**).*"

6.2.3 Hydro One Inc.'s Ability to Earn its Allowed ROE

A useful way of reviewing the performance of utilities is to examine their ability to earn their allowed ROEs on a consistent basis. In fact, DBRS analyzes this issue in its debt rating report for HOI (as it does for other regulated utilities), which it includes on pages 9 and 10 of its report. The ROE analysis provided by DBRS, which I have confirmed is correct, is included and summarized in Attachment M of my evidence.[77] The analysis in Attachment M shows that HOI Distribution earned above its allowed ROE by a wide margin every year since 2018, with an average earned excess ROE of 1.17% over the 2018-2023 period, while HOI Transmission earned over allowed ROE every year from 2018 to 2023, with an average earned excess ROE of 1.11%. This evidence shows that HOI has been able to consistently earn its allowed ROEs or higher over the most recent six-year period. This can be considered a strong indicator that HOI possesses low total risk.

6.2.4 Hydro One Inc.'s Financial Risk and Credit Metrics

Strength #3 included in the DBRS report discussed above was that HOI had a "**Reasonable financial profile,"** with **"all key credit metrics reasonable for the current rating category."**

In Table 14 below, I replicate the table provided on page 2 of the DBRS rating report, which includes the three key metrics they emphasize: cash flow to total debt (%); total debt in capital structure (%); and, EBIT gross interest coverage (times). I further supplement that table from DBRS with information for one additional metric that it reports on page 14 of its report - EBITDA gross interest coverage.

[77] I also include the 2021 actual earned ROE for HO - Trans. that was not included in the DBRS report, which was obtained from "EB-2021-0110 I-6-I-CCC-57, Attach 2 (2015-2022). In addition, I updated 2022 HO – Trans. data, and 2023 data for HO – Trans. and HO – Dist., which was obtained from EB-2024-0063 provided by the OEB on July 12, 2024.

TABLE 14

HYDRO ONE INC. CREDIT METRICS (2018-2023)

	Cash flow/total debt (%)	Total debt in capital structure (%)	EBIT Gross Interest Coverage	EBITDA Gross Interest Coverage
2023	14.1	55.6	3.13	4.64
2022	14.5	55.8	3.41	5.05
2021	13.8	55.9	3.24	4.87
2020	12.7	56.1	3.05	4.59
2019	13.7	56.6	2.96	4.51
2018	13.0	56.7	2.87	4.48

As noted by DBRS, HOI's metrics are strong. For example, on page 8 of DBRS' June 2024 discussion of its methodologies for rating regulated utilities, it reports the following guidelines it uses to conduct its Financial Risk Assessment (FRA) of "fully regulated utilities with only moderate exposure to nonregulated operations": [78]

Regulated Utility – FRA Metrics

Metric	AA	A	BBB	BB/B
Cash flow-to-debt (%)	> 17.5	12.5 to 17.5	10.0 to 12.5	0.0 to 10.0
Debt-to-capital (%)	< 55	55 to 65	65 to 75	75 to 90
EBIT-to-interest (x)	> 2.8	1.8 to 2.8	1.5 to 1.8	1.0 to 1.5

Comparing HOI's credit metrics provided in Table 14 to the thresholds used by DBRS shows that:

1. HOI's Cash flow-to-debt ratios have fallen comfortably in the "A" range (12.5 to 17.5) over the 2018-2023 period used by DBRS, ranging from 12.7 to 14.5, and sitting at 14.1 in 2023.
2. HOI's Debt-to-capital metric is at the very low end of the "A" range (55 to 65), bordering on the "AA" category, and ranged from 55.6 to 56.7 over the period.
3. HOI's EBIT-to-interest ratios have fallen within the "AA" range (>2.8) used by DBRS over the entire period, and sat at 3.13 as of 2023.

[78] This document is appended to my evidence as Attachment BJ.

TAB 15

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Consumers Council of Canada (CCC)

Reference:

Ex. M4/pp. 93, 101, 107

Questions:

a) With respect to the use of peer groups in your study (as set out in Tables 8, 10 (which shows an average based on the peer companies set out in Appendix J), and the unlabeled table on p. 107), please confirm or correct the following understanding:

i. For the CAPM calculation, the Canadian and US peer groups are not directly used but inform the potential accuracy of the beta of 0.45 that is applied.

ii. For the DCF calculation, Panel A (Canadian Sample) is used to determine the DCF-derived ROE.

iii. For the BYPRP calculation, Fortis Alberta, Fortis BC, Canadian Utilities, Enbridge Gas and Hydro One, are used to determine the appropriate average bond yield.

b) Please advise whether the peer groups are used in any other calculation beyond what is discussed in part (a) of this question.

c) Please explain the reason for the difference in the companies included in Panel A (Canadian Sample) and the group of companies used in the BYPRP calculation.

d) For Panel A (Canadian Sample), please provide a table that includes the following information (if available):

i. Company name
ii. Credit rating
iii. S&P business risk rating
iv. S&P financial risk rating
v. Percentage of operating income from, as applicable, electricity distribution, electricity transmission, electricity generation, natural gas operations
vi. Percentage of operating income, as applicable, by operating area (i.e., electricity distribution, transmission, generation or natural gas operations) that is regulated
vii. Percentage of overall operating income that is regulated
viii. The regulatory agency that regulates the company (i.e., OEB, AUC, etc.) and the applicable rating as set out in the “Utility Regulatory Jurisdiction Assessment performed by S&P Global” (see p. 129 of Exhibit M1 – LEI

Expert Report)

ix. Description of ratemaking approach applied to the company. As part of this response, please include information regarding:

i. Most prevalent form of ratemaking (e.g., cost of service, cost of service plus IRM, etc.)
ii. Application of a forward test year approach in cost of service ratemaking
iii. Availability of Custom IR option (which, as applied in Ontario, allows for multi-year (typically 5 years) recovery of approved capital budgets as proposed by the utility)
iv. Availability of mechanisms that allow the recovery of incremental capital between rebasing proceedings (and a description of how those mechanisms operate)
v. Reliance on fixed vs. variable rates (by rate class)
vi. Availability of deferral and variance accounts for non pass-through costs and revenues (and the types of accounts that are available)
vii. Availability of Z-factor relief (and the types of relief available through this mechanism)
viii. Availability of off-ramp provisions when actual ROE falls below a certain threshold

Responses:

a. i. Confirmed.

ii. Confirmed.

iii. Not confirmed. As discussed in Section 5.4 of Exhibit M4, Dr. Cleary rounded up the June 5, 2024 A-rated utility yield of 4.68% to 4.7%, but he referenced the average yield for the Canadian operating utilities noted in the question.

iv. The five Canadian utilities Dr. Cleary uses in his DCF analysis are the same five that are reported in Table 8 of his evidence: Algonquin; CU Ltd.; Emera; Fortis; and, Hydro One Ltd.

Dr. Cleary notes that his sample of Canadian utilities reported in Table 8 includes the five utilities that were determined to be “reasonable comparable Canadian utilities” during the 2024 Alberta GCOC Proceedings based on the results of a lengthy process involving party submissions, a technical conference, and ensuing follow up on remaining issues.[1]

b. The samples are not used directly in any other calculations in Exhibit M4.

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[1] As noted in the November 10, 2022 Alberta Utilities Commission (AUC) memorandum to all parties, titled “Proceeding 27084, Determination of the Cost-of Capital Parameters in 2024 and Beyond: Appendix A – Finalized screening criteria,” (27084-X0256 2022-11-10 Appendix A - Finalized screening criteria).

c. Dr. Cleary did not use the yields for these utilities directly in his BYPRP calculations as discussed in response to question (a) part (iii) above. The sample differs from his Canadian sample provided in Table 8 because they are Canadian "operating" utilities that issue debt directly, so he felt the debt yields were most comparable to Ontario operating utilities. However, these utilities are not publicly traded, as are the Canadian holding companies included in Dr. Cleary's Canadian sample. As a result, the market data needed to apply the CAPM and DCF approaches would not be available for these operating utilities.

d. Parts i and ii[1]

Utility Name	DBRS Rating	S&P Rating	Moody's Rating
Algonquin Power & Utilities Corp.	BBB(Stable)	BBB	NA
Canadian Utilities Ltd.	A	BBB+	NA
Emera Inc.	N/A	BBB	Baa3
Fortis Inc.	A(Low)	A-	Baa3
Hydro One Ltd.	A(High)	A	A3

Parts iii, iv and v:
Dr. Cleary does not have the available data to respond to these requests.

Parts vi and vii:
Dr. Cleary does not have the most recent data available to respond to these requests. However, lease see response to M4-2-OEA-11, part c) for the data that Dr. Cleary can report.

Parts vii and ix:
Dr. Cleary does not have the data available to respond to these requests.

[1] The S&P and Moody's ratings provided for Algonquin, CU Ltd., Emera and Fortis were obtained from Concentric's response to IGUA interrogatory #54 during the 2023 EGI rebasing proceedings, so some may have changed since then.

TAB 16

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Ontario Energy Association (OEA)

Reference:

Exhibit M4
Pages 1-4

Preamble:

I provided expert evidence sponsored by the Industrial Gas Users Association (IGUA) in the 2023 EGI rebasing proceedings (EB-2022-0200). I have served as an expert witness on behalf of the Office of the Utilities Consumer Advocate of Alberta on several occasions including generic cost of capital proceedings in 2013-2014 (Proceeding ID 2191), 2015-2016 (Proceeding ID 20622), 2018 (Proceeding ID 22570), 2019-20 (Proceeding ID 24110), 2022-23 (Proceeding ID 27084), as well as the generic regulated rate option proceeding (Proceeding ID 2941) in 2014 and the EPCOR Energy Alberta 2018-2021 Energy Price Setting Plan4 proceeding (Proceeding ID 2357) in 2017. I also prepared evidence on behalf of the Newfoundland Consumer Advocate in cost of capital hearings in 2015-2016, and in 2018.

Question:

a. For each proceeding where Dr. Cleary developed recommendations for ROE and /or capital structure referenced above, please provide a table with Dr. Cleary's recommendations and the ultimate decision by the regulator.

Response:

Dr. Cleary has provided a table below that shows these Decisions, his recommendations, the recommendations of other experts involved in those proceedings, and the mid-point and average of those recommendations. This table shows that the recommendations have generally displayed very large ranges, with the final decisions usually being very close to the mid-points and/or averages of these ranges. The utilities' experts' recommendations have consistently been at the high end of the total range, and Dr. Cleary's have been at the low end (consistent with his assertion as supported in Section 5.1 of his evidence that the allowed ROEs in Canada (and the U.S.) have simply been too high for several years).

Summary of Previous Decisions

	OEB 2023 (EGI Rebasing) (%)	**AUC 2015 (2013 GCOC Decision) (%)**	**AUC 2016 (%)**	**AUC 2018 (%)**	**AUC 2021 (%)[1]**	**AUC 2023 (%)**	**Newf. 2016 (%)**
Awarded ROE	**N/A**	**8.30 (2013-2015)**	**8.30 for 2016 / 8.50 for 2017**	**8.50**	**Extended 2018 Decision** **8.50**	**Base ROE** **9.0**	**8.5**
Mid-Point (Average) of Recom. Range of Recom.		8.68 (8.16) 6.8-10.5	8.75 (8.62) 7.0-10.5	8.53 (8.92) 6.3-10.75		8.53 (8.85) 6.75-10.3	8.5 (8.5) 7.5-9.5
Concentric (Coyne)				9.50		9.5	9.5
McShane		10.50					
Hevert			9.0-10.5	9.0-10.75			
D'Ascendis						10.3	
Villadsen			10.25	10.0		10.0	
Booth		7.50	7.50				7.5

[1] These proceedings were delayed and ultimately suspended due to COVID, etc.

Cleary		**6.78 (2013) / 7.27 (2014) / 7.42 (2015)** **(Avg. of 7.16)**	**7.0**	**6.3**		**6.75**	
CCA		7.50[1]					
Madsen						7.70	
Awarded Equity Ratio	**38.0**	**Various - utility specific (36.0-42.0)**	**Various - utility specific (36.0-42.0)**	**Various - utility specific** **(36.0-42.0) (37.0 for ENMAX)[2]**	**Various - utility specific** **Extended 2018 Decision** **(37.0 for most - 39.0 for Apex)**	**Various - utility specific** **(37.0 for most - 39.0 for Apex)**	**45%**

[1] Accepted Booth's ROE recommendations.

[2] Note in paragraph 813. The Commission stated: "In Section 9.9, the Commission reviewed the recommendation of Mr. Coyne that the income-tax-exempt utilities should receive a 200 bps adder to their deemed equity ratio. Based on its findings in that section, the Commission determined that no adder was warranted."

Mid-Point of Recom. Range Range of Recom.	39 (36.0-42.0)	36.0-43.0 39.0-45.0 to 33.0-41.0 37.5-50.0 to 30.0-40.0	36.5-42.5 38.0-44.0 to 35.0-41.0	37.5-42.5 40.0-44.0 to 35.0-41.0		39.5 (35.0-44.0)	42.5 (40.0 to 45.0)
Concentric / Coyne	42.0			42.0 (ENMAX – T&D)		40.0 (ENMAX-T&D)	45.0
McShane		39.0-45.0					
Hevert			38.0-42.0	40.0			
D'Ascendis						40.0	
Villadsen			38.0-44.0	40.0-44.0		40.0-44.0	
Booth		35.0 (ATCO Gas & ATCO Pipelines)	35.0 (ATCO Gas & ATCO Pipelines)				
Cleary	**36.0**	**33.0-40.0**	**35.0-41.0**	**36.0-41.0 (36.0 ENMAX T&D)**		**37.0 (39.0 for Apex)**	**40.0**

CCA		35.0-41.0		35.0-41.0[1]			
Madsen						35.0	
Johnson				35.0 (ATCO GAs)			

[1] Recommending expert Madsen.

TAB 17

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Ontario Energy Association (OEA)

Reference:

Exhibit M4
Page 31, lines 17-18

Preamble:

LEI's DCF analysis is flawed by its heavy reliance on data for U.S. utilities rather than Canadian utilities.

Questions:

a. Please indicate which Canadian utilities Dr. Cleary recommends as proxies for Ontario's utilities for purposes of estimating the cost of capital and why.
b. Please indicate which Canadian gas utilities Dr. Cleary recommends as proxies for Ontario's gas utilities for purposes of estimating the cost of capital and why.
c. Please provide a table showing the percentage of revenues and income for the most recent year the companies recommended by Dr. Cleary (in response to (a)) derive from Canadian regulated utility operations, U.S. regulated utility operations, and other.

Responses:

a. The five Canadian utilities Dr. Cleary uses in his DCF analysis are the five reported in Table 8 of his evidence: Algonquin; CU Ltd.; Emera; Fortis; and, Hydro One Ltd.

   Dr. Cleary relied upon this sample of Canadian utilities as being more representative of Ontario utilities than samples including U.S. utilities for the reasons discussed in his evidence. Dr. Cleary further notes that he also conducted a DCF analysis on 28 U.S. utilities that provided very similar final Ke estimates; although, he did not consider the U.S. sample results due to his concerns about the comparability of U.S. utilities.

   The Canadian sample that Dr. Cleary uses in his analysis are the five utilities that were determined by the Alberta Utilities Commission to be "reasonable comparable Canadian utilities" during the 2024 Alberta GCOC Proceedings. The AUC's determination was based on the results of a lengthy process involving party submissions, a technical conference, and ensuing follow up on remaining issues, as noted in the November 10, 2022 Alberta Utilities Commission (AUC) memorandum to all parties, titled "Proceeding 27084, Determination of the Cost-of Capital Parameters in 2024 and Beyond: Appendix A – Finalized screening criteria," (27084-X0256 2022-11-10 Appendix A - Finalized screening criteria).

b. Dr. Cleary did not break up his analysis into gas versus electric utilities. This is consistent with the approach taken by Concentric in basing its main recommendations on its North American combined group, which it deemed as the most representative results for Ontario utilities.

c. The most recent data that Dr. Cleary has available comes from Exhibit “24110-X0344 2020-03-10 Hevert-D’Ascendis IR Responses to UCA (1-22)” that was filed during the 2021 Alberta GCOC Proceedings, PDF pages 6-14 (attached to this response). That source provides data from 2018 company reports, as follows:

Utility	Canadian Operations Revenue	International Operations Revenue
Algonquin	4.27%	95.73%
CU Ltd.	95.34%	4.66%
Emera	23.30%	76.70%
Fortis	36.85%	57.52%
Hydro One Ltd.	100.0%	0.00%

Utility	Regulated Revenue	Unregulated	Combination
Algonquin	84.99%	15.01%	0.00%
CU Ltd.	N/A	2.76%	97.24%
Emera	89.82%	9.41%	1.59%
Fortis	97.93%	2.19%	N/A
Hydro One Ltd.	99.32%	0.68%	N/A

Net income information was not provided.

March 10, 2020

Hevert/D'Ascendis-UCA-2020FEB18-004
2021 Generic Cost of Capital
Application No. 24110-A001
Proceeding ID. 24110

Reference: **Exhibit 24110-X0053, Hevert/D'Ascendis GCOC Written Evidence, Table 2 - page 56**

Issue/Sub-Issue: **Canadian Utility Proxy Group**

Preamble: Mr. Hevert and Mr. D'Ascendis identify the six Canadian utilities included in their Canadian proxy group. The UCA requires further information regarding the Canadian utilities included.

Request:

(a) For each of the utilities listed in Table 2, please provide the following information:

i. All available debt ratings;
ii. The size of the company in terms of revenue and total assets;
iii. A list of all operating companies that are subsidiaries of each utility, as well as a list of the jurisdiction(s) in which these companies operate;
iv. The percentage breakdown of revenue, operating earnings and net income from each of the operating companies identified in part (iii);
v. The percentage breakdown of regulated versus unregulated portion of revenue, operating earnings and net income for the six utilities listed in Table 2;
vi. A similar breakdown to that requested in part (iv) for operations that are based in Canada, versus in other countries; and,
vii. A similar breakdown to that requested in part (iv) for operations related to transmission, distribution, generation, and other activities.

Response:

(a) i. Messrs. Hevert and D'Ascendis used S&P senior unsecured and issuer credit ratings as a criterion for the selection of his proxy companies. Messrs. Hevert and D'Ascendis obtained those ratings from S&P Global Market Intelligence.

	S&P Senior Unsecured Rating	S&P Issuer Rating
ATCO Limited	N/A	A-
Algonquin Power & Utilities Corp.	N/A	BBB
Canadian Utilities, Ltd.	BBB+	A-
Emera Inc.	BBB	BBB+
Fortis, Inc.	BBB+	A-
Hydro One Limited	N/A	A-

ii. From their respective 2018 annual reports, in millions of dollars:

	Revenue	**Total Assets**
ATCO Limited	$4,888	$23,344
Algonquin Power & Utilities Corp.	$1,647	$9,389
Canadian Utilities, Ltd.	$4,377	$21,819
Emera Inc.	$6,524	$32,314
Fortis, Inc.	$8,390	$53,051
Hydro One Limited	$6,150	$25,657

iii. ATCO Limited*

Segment	**Business**	**Jurisdictions**
Structures & Logistics	ATCO Structures & Logistics	Western Australia, British Columbia, Louisiana
Electricity	ATCO Electric	Alberta, Yukon, Northwest Territories, Yellowknife, NWT
	ATCO Power	Western Canada, Ontario, Mexico
	Alberta PowerLine	Alberta, Ontario
	ATCO Power Australia	Adelaide (South Australia), Karratha (Western Australia)
Pipelines & Liquids	ATCO Gas	Alberta, Lloydminster SK
	ATCO Pipelines	Alberta, Mexico
	ATCO Gas Australia	Perth (Australia)
	ATCO Energy Solutions	Alberta, Mexico
Corporate & Other	ATCO Energy	Alberta
Neltume Ports**	Neltume Ports S.A	Chile, Uruguay, Argentina, Brazil

*ATCO Limited owns controlling 52.2% of Canadian Utilities, Ltd.

**ATCO Limited owns non-controlling 40% of Neltume Ports

Algonquin Power & Utilities Corp.

Segment	Business	Jurisdictions
Generation	Liberty Power	North America, International
Transmission and Distribution	Liberty Utilities	Arizona, Arkansas, California, Georgia, Illinois, Iowa, Kansas, Massachusetts, Montana, Missouri, New Hampshire, Oklahoma, Texas

Canadian Utilities, Ltd.

Segment	Business	Jurisdictions
Electricity	ATCO Electric	Alberta, Yukon, Northwest Territories, Yellowknife, NWT
	ATCO Power	Western Canada, Ontario, Mexico
	Alberta Powerline	Alberta, Ontario
	ATCO Power Australia	Adelaide (South Australia), Karratha (Western Australia)
Pipelines & Liquids	ATCO Gas	Alberta, Lloydminster SK
	ATCO Pipelines	Alberta
	ATCO Gas Australia	Perth (Australia)
	ATCO Energy Solutions	Alberta, Mexico
Corporate & Other	ATCO Energy	Alberta

Emera Inc.

Segment	Business	Jurisdictions
Emera Florida and New Mexico	Tampa Electric	Florida
	Peoples Gas System	Florida
	New Mexico Gas Company	New Mexico
	SeaCoast	Florida
Nova Scotia Power Inc.		Nova Scotia
Emera Maine	Emera Maine	Maine
Emera Energy	Emera Energy Services	
	Emera Energy Generation	New England, Maritime provinces of Canada
Emera Caribbean	Barbados Light & Power Company	Barbados
	Grand Bahama Power Company Limited	Grand Bahama Island
	Dominica Electricity Services Ltd.	Dominica
Emera Corporate and Others	Emera Utility Services	Atlantic Canadian Provinces
	Emera Brunswick Pipeline	New Brunswick
	Emera Newfoundland & Labrador Holdings	Newfoundland

Fortis, Inc.

Segment	Business	Jurisdictions
Regulated Electric & Gas Utilities - US	ITC	Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas, Oklahoma
	UNS Energy	Arizona
	Central Hudson	New York
Regulated Gas & Electric Utilities – Canadian	FortisBC Energy	British Columbia
	Fortis Alberta	Alberta
	FortisBC Electric	British Columbia
	Newfoundland Power	Newfoundland Island, Labrador Island
	Maritime Electric	Prince Edward Island
	Fortis Ontario	Ontario (Fort Erie, Cornwall, Gananoque, Port Colborne, District of Algoma
Regulated Electric Utilities – Caribbean	Caribbean Utilities	Grand Cayman, Cayman Islands
	Fortis Turks and Caicos	Turks and Caicos Islands
Non-Regulated	ACGS	British Columbia

Hydro One Limited

Segment	Business	Jurisdictions
Transmission	Hydro One Networks Inc	Ontario
	Hydro One Sault Ste. Marie LP	Ontario
Distribution	Hydro One Networks	Ontario
	Hydro One Remote Communities	Ontario
Other	Hydro One Telecom Inc	Ontario

iv. Some of the 2018 annual reports of the proxy companies do not break down revenue, operating earnings, or net income by subsidiary. Where no subsidiary-specific information was available, segment-specific information was used. See Hevert-DAscendis-UCA-2020FEB18-004 Attachment.

	Revenue	Operating Earnings	Net Income
ATCO Limited			
Structures & Logistics	10.45%	0.80%	0.89%
Electricity	58.12%	73.41%	75.26%
Pipelines & Liquids	28.95%	26.45%	22.35%
Corporate and Other	2.48%	-2.39%	-2.09%
Algonquin Power & Utilities Corp.			
Generation	15.01%	12.85%	N/A
Distribution	84.99%	87.65%	N/A
Corporate and Other	0.00%	-0.50%	N/A
Canadian Utilities, Ltd.			
Electricity	64.91%	75.13%	78.78%
Pipelines & Liquids	32.33%	27.34%	23.40%
Corporate and Other	2.76%	-3.07%	-2.81%
Emera Inc.			
Emera Florida and New Mexico	56.33%	51.03%	60.28%
NSPI	22.07%	18.70%	18.45%
Emera Maine	4.26%	5.12%	6.20%
Emera Caribbean	7.16%	4.39%	5.77%
Emera Energy	9.41%	15.70%	23.24%
Corporate and Other	1.59%	5.06%	-13.94%
Fortis, Inc.			
ITC	17.93%	35.55%	34.06%
UNS Energy	26.25%	19.09%	22.78%
Central Hudson	11.01%	5.57%	5.75%
FortisBC Energy	14.15%	14.23%	12.13%
Fortis Alberta	6.90%	9.11%	9.33%
FortisBC Electric	4.86%	4.54%	4.35%
Other Electric	16.83%	8.99%	9.33%
Energy Infrastructure	2.19%	4.58%	7.70%
Corporate and Other	0.00%	-1.65%	-5.44%
Hydro One Limited			
Transmission	27.41%	64.32%	N/A
Distribution	71.90%	40.18%	N/A
Other	0.68%	-4.51%	N/A

v. Segments that contain a mix of regulated and non-regulated operations are summarized in the following table as "Combination". See Hevert-DAscendis-UCA-2020FEB18-004 Attachment.

	Revenue	**Operating Earnings**	**Net Income**
ATCO Limited			
Regulated	N/A	N/A	N/A
Unregulated	12.93%	-1.59%	-1.19%
Combination	87.07%	99.86%	97.62%
Algonquin Power & Utilities Corp.			
Regulated	84.99%	87.65%	N/A
Unregulated	15.01%	12.85%	N/A
Combination	0.00%	-0.50%	N/A
Canadian Utilities, Ltd.			
Regulated	N/A	N/A	N/A
Unregulated	2.76%	-3.07%	-2.81%
Combination	97.24%	102.47%	102.18%
Emera Inc.			
Regulated	89.82%	79.24%	90.70%
Unregulated	9.41%	15.70%	23.24%
Combination	1.59%	5.06%	-13.94%
Fortis, Inc.			
Regulated	97.93%	113.57%	97.74%
Unregulated	2.19%	2.93%	2.26%
Combination	N/A	N/A	N/A
Hydro One Limited			
Regulated	99.32%	104.51%	N/A
Unregulated	0.68%	-4.51%	N/A
Combination	N/A	N/A	N/A

vi. See Hevert-DAscendis-UCA-2020FEB18-004 Attachment.

	Revenue	Operating Earnings	Net Income
ATCO Limited			
Canadian Operations	90.30%	N/A	N/A
International Operations	9.70%	N/A	N/A
Algonquin Power & Utilities Corp.			
Canadian Operations	4.27%	N/A	N/A
International Operations	95.73%	N/A	N/A
Canadian Utilities, Ltd.			
Canadian Operations	95.34%	N/A	N/A
International Operations	4.66%	N/A	N/A
Emera Inc.			
Canadian Operations	23.30%	N/A	N/A
International Operations	76.70%	N/A	N/A
Fortis, Inc.			
Canadian Operations	36.85%	N/A	N/A
International Operations	57.52%	N/A	N/A
Hydro One Limited			
Canadian Operations	100.00%	100.00%	N/A
International Operations	0.00%	0.00%	N/A

vii. See Hevert-DAscendis-UCA-2020FEB18-004 Attachment.

	Revenue	Operating Earnings	Net Income
ATCO Limited			
Other (including utility)	87.07%	99.86%	97.62%
Other (non-utility)	12.93%	-1.59%	-1.19%
Algonquin Power & Utilities Corp.			
Distribution	84.99%	87.65%	N/A
Generation	15.01%	12.85%	N/A
Other (non-utility)	0.00%	-0.50%	N/A
Canadian Utilities, Ltd.			
Other (including utility)	97.24%	102.47%	102.18%
Other (non-utility)	2.76%	-3.07%	-2.81%
Emera Inc.			
Transmission & Distribution	4.26%	5.12%	6.20%
Vertically Integrated	85.56%	74.12%	84.51%
Generation	9.41%	15.70%	23.24%
Other (non-utility)	1.59%	5.06%	-13.94%
Fortis, Inc.			
Transmission	17.93%	35.55%	34.06%
Distribution	6.90%	9.11%	9.33%
Transmission & Distribution	14.15%	14.23%	12.13%
Vertically Integrated	58.95%	54.68%	42.22%
Generation	2.19%	4.58%	7.70%
Other (non-utility)	0.00%	-1.65%	-5.44%
Hydro One Limited			
Transmission	27.41%	64.32%	N/A
Distribution	71.90%	40.18%	N/A
Other (non-utility)	0.68%	-4.51%	N/A

TAB 18

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 19

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 20

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, Figure 19, p. 71

Question(s):

Note this interrogatory has been asked by LEI

It is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility, with 50 basis points being the norm.

a) Other than it being common practice, please provide the empirical basis (with examples of actual utility flotation costs) for recommending 50 basis points associated with floatation costs.

Response:

Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock, as well as price discounts and premiums. In his text, New Regulatory Finance, Dr. Roger Morin cited a 1996 study by Lee et. al., which found that the average flotation costs for regulated utilities are equal to approximately 5% of the gross proceeds of the equity issuance, with smaller issues tending to have a higher percentage.[1] This is consistent with recent research by the Enbridge Treasury team, which found that the average flotation costs for a sample of Canadian and U.S. utilities were also equal to slightly more than 5% of the gross proceeds. Based on Concentric's prior analysis of flotation costs, the empirical study cited by Dr. Morin, and the recent Enbridge analysis, our view is that flotation costs for utilities are within a range from 2% to 10%, with an average of around 5%. This can be translated into basis points of ROE by adjusting the dividend yield in the DCF model. Using this method, if f flotation costs are equal to 5% of the gross proceeds of the equity issuance, then the adjustment to ROE would be approximately 25 basis points for companies like those in Concentric's North American combined proxy group. Flotation costs at the higher end of the range (i.e., 10% of the gross proceeds), would equate to

[1] Dr. Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 323.

an approximately 45 basis points adjustment. Concentric notes that the 50 basis point adjustment approved by Canadian regulators also includes financial flexibility.
In addition to an adjustment for flotation costs, Canadian regulators in most jurisdictions including Ontario have also typically included an adjustment for financial flexibility. This adjustment provides a small cushion so that the utility may continue to raise equity in challenging capital market conditions.

According to Dr. Roger Morin, utilities need the ability to attract capital even during “market breaks” because they have an ongoing obligation to serve. For that reason, he recommends providing the utility an additional allowance for financial flexibility during difficult market conditions, as follows:

> *The flotation cost allowance of 5% allows for both the direct flotation costs and market pressure component but does not contain an explicit allowance for market break.*
>
> ***
>
> *Such an allowance is desirable, however. If negative events should occur during the time period from announcement of a public issue to actual pricing, the price could fall below book value unless a sufficient margin is maintained. Compared to non-regulated companies, utilities do not possess the same latitude and discretion in accessing capital markets in view of their obligation to serve. They must access capital markets regardless of capital market conditions. Therefore, they have limited ability to time security issuances in order to avoid an adverse market break.*[2]

[2] Dr. Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 326.

TAB 21

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

For each of CLD+ utilities, please provide:

a) Copies of all credit rating agency reports since 2009

b) Each year between 2009 and 2023, a table that shows approved (i.e. ROE include in base rates) vs actual regulated ROE. As part of that response, for i) Hydro One, please provide a further breakdown by regulated business (transmission and distribution), ii) OPG, please provide a breakdown by generating segment (nuclear and hydroelectric), iii) for Alectra, Elexicon, and Enbridge, who have been subject to major MAAD transactions since 2009, please provide information for predecessor utilities for the applicable years.

c) Details of all equity investments received since 2009, including the date, amount, and source (direct shareholder investment, indirect shareholder investment through holding company, and share sale).

d) A table that shows for all outstanding long-term debt, i) date of issuance, ii) term, iii) maturity date, iv) principal, v) interest rate, vi) type of debt instrument (e.g. public bond, private placement, loan, promissory note, swap, etc.) vii) source of debt (e.g. TD Bank, infrastructure Ontario, shareholder, etc.) and viii) indicate if the debt issued is at the LDC or holding company level.

e) For each year between 2009 and 2024, actual capital structure.

Response to a):

Enbridge Gas Inc.:

Please see N-M2-10-SEC-41 – Attachment 1 (Enbridge Gas Inc.) for all relevant Enbridge Gas Inc. credit rating agency reports from the past 5 years. The reports are provided in one file and are numerated below.

Appendix	Rating Agency	Title
1	DBRS	DBRS EGI RR Oct 2019
2	DBRS	DBRS EGI RR Sep 2020
3	DBRS	DBRS EGI RR Oct 2021
4	DBRS	DBRS EGI RR Sep 2022
5	DBRS	DBRS EGI RR Sep 2023
6	S&P	S&P EGI Apr 2020
7	S&P	S&P EGI Jan 2021
8	S&P	S&P EGI Feb 2022
9	S&P	S&P EGI Jul 2022
10	S&P	S&P EGI Jul 2023
11	S&P	S&P EGI Sep 2023 Research Update
12	S&P	S&P EGI Jun 2024 Research Update

OPG:

OPG's credit rating reports are provided in N-M2-10-SEC-41 – Attachment 2 (OPG).

Appendix	Rating Agency	Title
1	DBRS	DBRS 2019-2024
2	Moody's	Moody's 2019-2024
3	S&P	S&P 2019-2024

UCT 2:

Rating reports can be obtained from the links below and copies are also attached as N-M2-10-SEC-41 – Attachment 3 (UCT 2).

May 2024: https://dbrs.morningstar.com/research/432193/morningstar-dbrs-confirms-east-west-ties-ratings-at-a-low-with-stable-trends

May 2023: https://dbrs.morningstar.com/research/413338/dbrs-morningstar-finalizes-provisional-ratings-of-a-low-with-stable-trends-on-east-west-tie-limited-partnership

March 2023: https://dbrs.morningstar.com/research/411675/dbrs-morningstar-assigns-provisional-ratings-of-a-low-with-stable-trends-to-east-west-tie-limited-partnership

Hydro One:

Copies of the following credit rating agency reports since 2019 are attached as N-M2-10-SEC-41 – Attachment 4 (Hydro One).

Reference #	Ratings Agency	Title
1	DBRS	DSRS HOI April 15 2019
2	DBRS	DBRS HOI April 16 2020
3	DBRS	DBRS HOI May 3 2022
4	DBRS	DBRS HOI Nov 9 2022
5	DBRS	DBRS HOI Nov 20 2023
6	Moody’s	Moody’s HOI 20Dec10
7	Moody’s	Moody’s HOI Nov 25 2021
8	Moody’s	Moody’s HOI May 30 2023
9	Moody’s	Moody’s HOI 26Jul2024
10	S&P	S&P HOI Feb 24 2020
11	S&P	S&P HOI Mar 11 2021
12	S&P	S&P HOI Apr 15 2022
13	S&P	S&P HOI Mar 17 2023
14	S&P	S&P HOL June 10 2024

Hydro Ottawa Limited:

Hydro Ottawa Limited does not maintain a credit rating with a credit rating agency. Accordingly, there are no “distributor stand alone” credit rating agency reports to provide.

The following credit rating agency reports have been issued since 2019, pertaining to Hydro Ottawa Holding Inc., and are attached as N-M2-10-SEC-41 – Attachment 5 (Hydro Ottawa Holding):

- Standard & Poor’s RatingsDirect report for Hydro Ottawa Holding Inc. dated September 25, 2019
- Standard & Poor’s Research Update for Hydro Ottawa Holding Inc. dated January 13, 2020
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated September 25, 2019
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated September 30, 2020
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated October 29, 2021

- DBRS Rating Report for Hydro Ottawa Holding Inc. dated October 19, 2022
- DBRS Rating Report for Hydro Ottawa Holding Inc. dated October 18, 2023

Toronto Hydro:

Please see N-M2-10-SEC-41 – Attachment 6 (Toronto Hydro) for all relevant Toronto Hydro credit rating agency reports from the past 5 years.

Reference	Rating Agency	Title
1	DBRS	Toronto Hydro – DBRS – 2019
2	DBRS	Toronto Hydro – DBRS – 2020
3	DBRS	Toronto Hydro – DBRS – 2021
4	DBRS	Toronto Hydro – DBRS – 2022
5	DBRS	Toronto Hydro – DBRS – 2023
6	DBRS	Toronto Hydro – DBRS – 2024
7	S&P	Toronto Hydro – S&P – 2019
8	S&P	Toronto Hydro – S&P – 2020
9	S&P	Toronto Hydro – S&P – 2021
10	S&P	Toronto Hydro – S&P – 2022_1
11	S&P	Toronto Hydro – S&P – 2022_2
12	S&P	Toronto Hydro – S&P – 2023
13	S&P	Toronto Hydro – S&P – 2024_1
14	S&P	Toronto Hydro – S&P – 2024_2

Alectra Inc.:

Please see N-M2-10-SEC-41 – Attachment 7 (Alectra) for all relevant Alectra credit rating agency reports from the past five years.

Reference	Rating Agency	Title
1	DBRS	Alectra Inc DBRS 2019
2	DBRS	Alectra Inc DBRS 2020
3	DBRS	Alectra Inc DBRS 2021
4	DBRS	Alectra Inc DBRS 2022
5	DBRS	Alectra Inc DBRS 2023
6	DBRS	Alectra Inc DBRS 2024
7	Fitch	Alectra Inc Fitch 2023
8	Fitch	Alectra Inc Fitch 2024

9	S&P	Alectra Inc S&P 2019
10	S&P	Alectra Inc S&P 2020
11	S&P	Alectra Inc S&P 2021
12	S&P	Alectra Inc S&P 2022
13	S&P	Alectra Inc S&P 2023
14	S&P	Alectra Inc S&P 2024

Elexicon Energy Inc:

Please see N-M2-10-SEC-41 – Attachment 8 (Elexicon) for all relevant Elexicon credit rating agency reports from the past five years.

1	DBRS	Elexicon Rating Report 2020 May 8
2	DBRS	Elexicon Rating Report 2021 May 10
3	DBRS	Elexicon Rating Report 2022 August 23
4	DBRS	Elexicon Rating Report 2023 July 5
5	DBRS	Elexicon Rating Report 2024 July 3

Response to b):

Elexicon Energy Inc:

	2019	2020	2021	2022	2023
Actual	7.61%	6.80%	6.87%	4.86%	5.15%
Deemed	9.43%	9.43%	9.43%	9.43%	9.43%

Toronto Hydro:

	2019	2020	2021	2022	2023
Actual	8.44%	5.90%	7.08%	7.44%	6.80%
Deemed	9.30%	8.52%	8.52%	8.52%	8.52%

<u>Enbridge Gas Inc.:</u>

Enbridge Gas Inc.'s 2019 – 2023 actual utility ROE's, and the ROE's included in rates, are provided in the table below.

		Col. 1	Col. 2
Line No.	Year	Actual Utility ROE	ROE in Base Rates
		%	%
			Union / EGD Rate Zones
1.	2019	10.47	8.93 / 9.00
2.	2020	8.72	8.93 / 9.00
3.	2021	9.17	8.93 / 9.00
4.	2022	9.52	8.93 / 9.00
5.	2023	6.35	8.93 / 9.00

<u>Alectra:</u>

Year	Approved ROE	Actual ROE
2019	8.95%	7.21%
2020	8.95%	4.80%
2021	8.95%	6.18%
2022	8.95%	6.70%
2023	8.95%	7.55%

<u>UCT 2</u>

Year	Actual ROE	Approved ROE
2022	9.42%	8.34%
2023	9.31%	8.34%

Hydro One:

Below is a table that outlines the OEB approved and achieved ROEs for Transmission and Distribution

Transmission

	2019*	2020	2021	2022	2023
Deemed ROE	N/A	8.52	8.52	8.52	9.36
Achieved ROE	9.53%	9.29%	9.30%	9.92%	10.80%

*2019 was an inflationary filing

Distribution

	2019	2020	2021	2022	2023
Deemed ROE	9.00	9.00	9.00	9.00	9.36
Achieved ROE	10.90%	10.56%	10.99%	10.10%	10.88%

Hydro Ottawa:

Year	**2019**	**2020**	**2021**	**2022**	**2023**
Hydro Ottawa ROE	8.98%	8.98%	8.34%	8.34%	8.34%
Hydro Ottawa ROE achieved	8.82%	7.24%	8.49%	6.94%	6.15%

OPG:

OPG operates as a single company, with a single management structure/corporate cost structure, and a single OEB-authorized cost of capital that covers both the hydroelectric and nuclear generating facilities, and obtains corporate financing as a single company. Accordingly, OPG reports achieved return on equity for its prescribed facilities as a whole.

OPG's Regulated ROE

	2019	2020	2021	2022	2023
Actual	15.61%	17.22%	10.79%	12.68%	13.80%
Nuclear Deemed	8.78%	8.78%	8.78%	8.66%	8.66%

Hydroelectric Deemed	9.33%	9.33%	9.33%	9.33%	9.33%

Response to c):

Toronto Hydro:

On June 28, 2017, Toronto Hydro Corporation issued 200 common shares to its shareholder for total proceeds of $250.0 million, net of share issue costs and expenses.

On June 28, 2024, Toronto Hydro Corporation filed the following Material Change Report related to shareholder equity:
https://www.sedarplus.ca/csaparty/viewInstance/resource.html?node=W1580&drmKey=b87115a0c5ea1b95&drr=ss6b4650951600347cceb13bcd5b91b967b9ebdfe234b8bcde4c5e867b24c523e1c14901026484277ee266b1feddd5c7e7ux&id=0c11f8b7998bcd9668b76226759035c74a014ba8ed28aabf

Elexicon Energy: Elexicon Energy has not received any equity investment since the merger of its predecessor utilities in 2019.

Alectra: There have been no equity investments since 2019.

OPG: There were no shareholder equity injections in connection with OPG's regulated business since 2019.

Enbridge Gas Inc

Year	Date	Amount	Source
2019	**November 27, 2019**	**$800,000,000**	**Indirect Shareholder Investment through holding company**
2020	**December 10, 2020**	**$800,000,000**	**Indirect Shareholder Investment through holding company**
2021	**December 7, 2021**	**$975,000,000**	**Indirect Shareholder Investment through holding company**
2022	June 28, 2022	$500,000,000	**Indirect Shareholder Investment through holding company**
2022	September 26, 2022	$300,000,000	**Indirect Shareholder Investment through holding company**

2022 Total Contribution	**September 26, 2022**	**$800,000,000**	**Indirect Shareholder Investment through holding company**
2023 Total Contribution	-	None	-

<u>UCT 2:</u>

Equity investments were made in the form of direct shareholder investment.

Year	Amount ($ MMs)
2014	$19
2015	$7
2016	$8
2017	$15
2018	$23
2019	$111
2020	$275
2021	$231
2022	$196

<u>Hydro Ottawa:</u> No equity investments were received by Hydro Ottawa since 2019.

<u>Hydro One:</u> From 2019 to 2024, there have been no equity investments in the company.

Response to d):

<u>Toronto Hydro:</u>

Debenture Series	Date of Issuance	Terms (yrs)	Maturity Date	Principal	Interest Rate	Type of Debt Instrument	Source of Debt	Debt Issued is at the LDC or Holding Company Level
Series 14	12-Nov-2019	10	11-Dec-2029	$ 200,000,000	2.49%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 15	12-Nov-2019	30	10-Dec-2049	$ 200,000,000	3.04%	Promissory Note	THC - Holding Company	Debentures issued at the holding company

Series 16	15-Oct-2020	10	15-Oct-2030	$ 200,000,000	1.55%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 17	18-Oct-2021	10	20-Oct-2031	$ 150,000,000	2.52%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 18	18-Oct-2021	30	18-Oct-2051	$ 200,000,000	3.32%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 19	13-Oct-2022	30	13-Oct-2052	$ 300,000,000	5.00%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 20	14-Jun-2023	10	14-Jun-2033	$ 250,000,000	4.66%	Promissory Note	THC - Holding Company	Debentures issued at the holding company
Series 21	12-Oct-2023	5	12-Oct-2028	$ 200,000,000	5.18%	Promissory Note	THC - Holding Company	Debentures issued at the holding company

Elexicon Energy:

Type	Term	Issue date	Mature on	Rate	Amount (in thousands)	Debt Held By
Notes payable to the shareholders of the Corporation	Short Term	since merger	due on demand	4.13%	71,926	LDC
Notes payable to the Corporation	Long Term	since merger	December, 2034	5%	15,000	LDC
Notes payable to the Corporation	Long Term	since merger	December, 2039	OEB-deemed long-term debt rate, less 30bps	11,200	LDC
Loan payable to the Corporation	Long Term	September, 2016	September, 2031	5%	62	LDC
Loan payable to Town of Cobourg Holding Inc.	Long Term	February, 2019	February, 2044	6%	77	LDC
Long-term debt from TD Bank (SWAP Loan)	Long Term	November, 2023	November, 2028	5%	33,390	LDC
Long-term debt from TD Bank (SWAP Loan)	Long Term	August, 2023	August, 2028	5%	220,000	LDC
Notes payable to the shareholders,	Short Term	since merger	due on demand	4.13%	89,132	Corporation (Holding Company)

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%

Enbridge Gas Inc.

All long-term debt issuances by Enbridge Gas Inc. and its predecessor companies are public bonds issued in the Canadian debt capital markets. Investors primarily include pension funds, life insurance companies and asset managers.

Issuance Date	Maturity Date	Term (years)	Interest Rate	Currency	Notional
8/22/2014	8/22/2024	10	3.15%	CAD	$215,000,000
6/2/1995	12/2/2024	29	9.85%	CAD	$85,000,000
10/2/1995	10/2/2025	30	8.85%	CAD	$20,000,000
11/10/1995	11/10/2025	30	8.65%	CAD	$125,000,000
10/29/1996	10/29/2026	30	7.60%	CAD	$100,000,000
11/3/1997	11/3/2027	30	6.65%	CAD	$100,000,000
5/19/1998	5/19/2028	30	6.10%	CAD	$100,000,000
11/15/2002	11/15/2032	30	6.90%	CAD	$150,000,000
12/16/2003	12/16/2033	30	6.16%	CAD	$150,000,000
2/24/2006	2/25/2036	30	5.21%	CAD	$300,000,000
9/11/2006	9/11/2036	30	5.46%	CAD	$165,000,000
9/2/2008	9/2/2038	30	6.05%	CAD	$300,000,000
11/22/2010	11/22/2050	40	4.95%	CAD	$200,000,000
1/23/2011	7/23/2040	29	5.20%	CAD	$250,000,000
6/21/2011	6/21/2041	30	4.88%	CAD	$300,000,000
9/7/2011	11/22/2050	39	4.95%	CAD	$100,000,000
11/22/2013	11/22/2043	30	4.50%	CAD	$200,000,000
6/2/2014	6/2/2044	30	4.20%	CAD	$500,000,000
8/22/2014	8/22/2044	30	4.00%	CAD	$215,000,000
9/11/2015	9/11/2025	10	3.31%	CAD	$400,000,000
9/11/2015	8/22/2044	28	4.00%	CAD	$170,000,000
9/17/2015	9/17/2025	10	3.19%	CAD	$200,000,000
5/31/2016	6/1/2026	10	2.81%	CAD	$250,000,000
5/31/2016	6/1/2046	30	3.80%	CAD	$250,000,000
8/5/2016	8/5/2026	10	2.50%	CAD	$300,000,000
11/22/2017	11/22/2027	10	2.88%	CAD	$250,000,000
11/22/2017	11/22/2047	30	3.59%	CAD	$250,000,000
11/29/2017	11/29/2047	30	3.51%	CAD	$300,000,000
8/9/2019	8/9/2029	10	2.37%	CAD	$400,000,000
8/9/2019	8/9/2049	30	3.01%	CAD	$300,000,000
4/1/2020	4/1/2030	10	2.90%	CAD	$600,000,000
4/1/2020	4/1/2050	30	3.65%	CAD	$600,000,000
9/15/2021	9/15/2031	10	2.35%	CAD	$475,000,000
9/15/2021	9/15/2051	30	3.20%	CAD	$425,000,000
8/17/2022	8/17/2032	10	4.15%	CAD	$325,000,000
8/17/2022	8/17/2052	30	4.55%	CAD	$325,000,000
10/6/2023	10/6/2028	5	5.46%	CAD	$250,000,000

10/6/2023	10/6/2033	10	5.70%	CAD	$400,000,000
10/6/2023	10/6/2053	30	5.67%	CAD	$350,000,000
					$10,395,000,000

UCT 2:

As provided in EB-2023-0298, UCT 2's long-term debt is a 30-year $427,651,000 Senior Secured Fixed-Rate Partially Amortizing note with a 4.864% fixed interest rate. Long-term debt was issued on May 1, 2023.

Date of Issue	Term (yrs)	Maturity Date	Principal	Interest Rate	Type
May 1, 2023	30	May 1, 2053	$427,651,000	4.864 %	Senior Secured Fixed-Rate Partially Amortizing Note

Hydro Ottawa:

Date of Issuance	**Term (Years)**	**Maturity Date**	**Principal ($)**	**Interest Rate**	**Type of Debt Instrument**	**Source of Debt (Creditor)**[1]	**Issuer (Debtor)**[2]
9/Feb/15	10.0	3/Feb/25	138,667,000	2.614%	Promissory Note	Hydro Ottawa Holding Inc. ("HOHI")	Hydro Ottawa Limited ("HOL")
9/Feb/15	30.0	2/Feb/45	121,333,000	3.639%	Promissory Note	HOHI	HOL
14/May/13	30.0	14/May/43	107,185,000	3.991%	Promissory Note	HOHI	HOL
14/May/13	23.6	19/Dec/36	50,000,000	4.968%	Promissory Note	HOHI	HOL
25/Jun/15	10.0	25/Jun/25	15,999,000	2.614%	Promissory Note	HOHI	HOL
25/Jun/15	30.0	25/Jun/45	14,001,000	3.639%	Promissory Note	HOHI	HOL
16/Oct/19	10.0	16/Oct/29	87,500,000	2.660%	Promissory Note	HOHI	HOL

16/Oct/19	30.0	16/Oct/49	162,500,000	3.210%	Promissory Note	HOHI	HOL
5/Jul/21	on demand	on demand	80,000,000	3.570%	Grid Note	HOHI	HOL
9/Aug/22	on demand	on demand	30,000,000	4.940%	Grid Note	HOHI	HOL
7/Jul/23	on demand	on demand	30,000,000	4.560%	Grid Note	HOHI	HOL

Hydro One:

For Hydro One Inc.

Outstanding Debt as at August 20, 2024

Hydro One Inc.

Offering Date	Term (Years)	Maturity Date	Principal Amount ($Millions)	Coupon Rate	Yield
28-Feb-20	5.0	28-Feb-25	400.0	1.76%	1.77%
26-Jun-18	7.0	26-Jun-25	350.0	2.97%	2.97%
20-Oct-23	2.0	20-Oct-25	400.0	5.54%	5.54%
24-Feb-16	10.0	24-Feb-26	500.0	2.77%	2.77%
21-Sep-23	3.0	21-Sep-26	425.0	CORRA+0.5%	Variable
27-Oct-22	5.3	27-Jan-28	750.0	4.91%	4.91%
5-Apr-19	10.0	5-Apr-29	550.0	3.02%	3.02%
27-Jan-23	6.8	30-Nov-29	300.0	3.93%	3.93%
12-Jan-24	5.9	30-Nov-29	250.0	3.93%	4.09%
28-Feb-20	10.0	28-Feb-30	400.0	2.16%	2.16%
3-Jun-00	30.0	3-Jun-30	400.0	7.35%	7.36%
9-Oct-20	10.3	16-Jan-31	400.0	1.69%	1.70%
17-Sep-21	10.0	17-Sep-31	450.0	2.23%	2.24%
22-Jun-01	31.0	1-Jun-32	300.0	6.93%	6.94%
17-Sep-02	29.7	1-Jun-32	200.0	6.93%	6.60%
27-Jan-23	10.0	27-Jan-33	450.0	4.16%	4.16%
31-Jan-03	31.0	31-Jan-34	200.0	6.35%	6.36%
25-Jun-04	29.6	31-Jan-34	120.0	6.35%	6.29%
24-Aug-04	29.5	31-Jan-34	65.0	6.35%	6.05%
12-Jan-24	10.1	1-Mar-34	550.0	4.39%	4.40%
20-Aug-24	10.4	4-Jan-35	700.0	4.25%	4.25%
19-May-05	31.0	20-May-36	350.0	5.36%	5.37%
24-Apr-06	30.1	20-May-36	250.0	5.36%	5.41%

13-Mar-07	30.0	13-Mar-37	400.0	4.89%	4.89%
3-Mar-09	30.0	3-Mar-39	300.0	6.03%	6.03%
16-Jul-09	31.0	16-Jul-40	300.0	5.49%	5.50%
15-Mar-10	30.4	16-Jul-40	200.0	5.49%	5.42%
26-Sep-11	30.0	26-Sep-41	300.0	4.39%	4.40%
22-Apr-03	40.0	22-Apr-43	250.0	6.59%	6.59%
20-Aug-04	38.7	22-Apr-43	65.0	6.59%	6.03%
9-Oct-13	30.0	9-Oct-43	435.0	4.59%	4.59%
6-Jun-14	30.0	6-Jun-44	350.0	4.17%	4.18%
24-Feb-16	30.0	23-Feb-46	350.0	3.91%	3.92%
19-Oct-06	40.0	19-Oct-46	75.0	5.00%	5.01%
13-Sep-10	36.1	19-Oct-46	250.0	5.00%	4.95%
18-Nov-16	31.0	18-Nov-47	450.0	3.72%	3.72%
26-Jun-18	31.0	25-Jun-49	750.0	3.63%	3.63%
28-Feb-20	30.0	28-Feb-50	300.0	2.71%	2.71%
9-Oct-20	29.4	28-Feb-50	200.0	2.71%	2.70%
5-Apr-19	31.0	5-Apr-50	250.0	3.64%	3.64%
17-Sep-21	30.0	15-Sep-51	450.0	3.10%	3.10%
22-Dec-11	40.0	22-Dec-51	100.0	4.00%	4.00%
22-May-12	39.6	22-Dec-51	125.0	4.00%	4.00%
27-Jan-23	30.0	27-Jan-53	300.0	4.46%	4.46%
30-Nov-23	31.0	30-Nov-54	400.0	4.85%	4.86%
12-Dec-23	31.0	30-Nov-54	100.0	4.85%	4.56%
20-Aug-24	30.3	30-Nov-54	500.0	4.85%	4.64%
31-Jul-12	50.0	31-Jul-62	75.0	3.79%	3.79%
16-Aug-12	50.0	31-Jul-62	235.0	3.79%	3.80%
29-Jan-14	50.0	29-Jan-64	50.0	4.29%	4.29%

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

All debt listed above is public debt issued in the Canadian debt capital market

OPG:

OPG is filing its table confidentially due to commercially sensitive information. A redacted version is provided below.

List of Outstanding Debt Supporting Regulated Operations Issued since 2019($M)

Line No.	Issue	Issue Date	Term (years)	Maturity Date	Principal*	Interest Rate (%)	Type of Debt Instrument	Source of Debt	Debt issued at LDC/Holdco Level
	List of outstanding debt issued since 2019								
1	OEFC Debt	8/22/2019	20.0	8/22/2039	100.0	3.49%	Loan	OEFC Credit Facility	OPG
2	Green Bond	1/18/2019	30.0	1/18/2049	0.4	4.25%	Public Bond	Capital Market	OPG
3	Green Bond	7/18/2022	10.0	7/19/2032	297.9	4.92%	Public Bond	Capital Market	OPG
4	Green Bond	6/28/2024	10.0	6/28/2034	496.7	4.83%	Public Bond	Capital Market	OPG
5	Green Bond	6/28/2024	30.0	6/28/2054	496.2	4.99%	Public Bond	Capital Market	OPG
6	Insurance Linked Bond	1/5/2022	5.0	1/4/2027	25.0	9.19%	Insurance Linked Bond	Private Placement	OPG
7	CIB*	10/14/2022	[redacted]	[redacted]	78.0	[redacted]	Loan	CIB	OPG
8	CIB*	4/11/2023	[redacted]	[redacted]	85.0	[redacted]	Loan	CIB	OPG
9	CIB*	9/29/2023	[redacted]	[redacted]	91.0	[redacted]	Loan	CIB	OPG
10	CIB*	12/18/2023	[redacted]	[redacted]	68.0	[redacted]	Loan	CIB	OPG
11	CIB*	3/22/2024	[redacted]	[redacted]	77.0	[redacted]	Loan	CIB	OPG
12	CIB*	6/19/2024	[redacted]	[redacted]	87.0	[redacted]	Loan	CIB	OPG

*Term, Maturity Date and Interest Rate redacted for commercial sensitivity

Response to e):

Toronto Hydro:

	2019	2020	2021	2022	2023
Actual	55.1%	57.1%	57.8%	60.0%	61.5%

OPG

	2019	2020	2021	2022	2023
Actual Equity Ratio[1]	62.7%	71.2%	77.3%	78.3%	78.3%

[1] Given that OPG's regulated operations form part of OPG's overall business, and are not operated as a standalone entity, the percentages shown have been derived by adding the "Other Long-Term Debt Provision" in OPG's deemed capital structure for the regulated facilities, as shown in OPG's actual historical capitalization tables reported to the OEB, to the deemed equity.

<u>Enbridge Gas Inc.</u>

Enbridge Gas Inc.'s actual utility capital structure for each of 2019 – 2023 is provided in the table below.

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (col 1x col 3) Return
		($Millions)	%	%	%	($Millions)
EGI 2019 Actual Utility Capital Structure						
1.	Long and Medium-Term Debt	8,002.0	60.90	4.45	2.71	356.1
2.	Short-Term Debt	407.0	3.10	2.04	0.06	8.3
3.		8,409.0	64.00		2.77	364.4
4.	Common Equity	4,730.0	36.00	10.47	3.77	495.5
5.		13,139.0	100.00		6.54	859.9
EGI 2020 Actual Utility Capital Structure						
6.	Long and Medium-Term Debt	8,568.5	63.18	4.38	2.77	375.3
7.	Short-Term Debt	111.1	0.82	0.94	0.01	1.0
8.		8,679.7	64.00		2.78	376.3
9.	Common Equity	4,882.3	36.00	8.72	3.14	425.6
10.		13,562.0	100.00		5.91	801.9
EGI 2021 Actual Utility Capital Structure						
11.	Long and Medium-Term Debt	8,505.3	59.81	4.37	2.61	371.3
12.	Short-Term Debt	596.5	4.19	0.31	0.01	1.9
13.		9,101.8	64.00		2.63	373.2
14.	Common Equity	5,119.8	36.00	9.17	3.30	469.4

15.		14,221.6	100.00		5.93	842.6

EGI 2022 Actual Utility Capital Structure

16.	Long and Medium-Term Debt	9,049.8	58.84	4.25	2.50	384.9
17.	Short-Term Debt	794.3	5.16	2.31	0.12	18.4
18.		9,844.1	64.00		2.62	403.4
19.	Common Equity	5,537.3	36.00	9.52	3.43	526.9
20.		15,381.4	100.00		6.05	930.2

EGI 2023 Actual Utility Capital Structure

21.	Long and Medium-Term Debt	9,498.1	59.89	4.21	2.52	399.7
22.	Short-Term Debt	651.6	4.11	5.04	0.21	32.9
23.		10,149.7	64.00		2.73	432.6
24.	Common Equity	5,709.2	36.00	6.35	2.29	362.7
25.		15,858.9	100.00		5.02	795.4

Elexicon Energy:

	2019	2020	2021	2022	2023
Debt (%)	47.5%	51.8%	54.1%	57.1%	59.2%
Equity (%)	52.5%	48.2%	45.9%	42.9%	40.8%

Alectra:

Year	Actual Total Debt to Equity Ratio	Actual Equity Ratio
2023	1.24	44.7%
2022	1.21	45.3%
2021	1.13	47.0%
2020	1.20	45.4%
2019	1.16	46.4%

UCT 2

Year	Regulated Capital Structure
2022	56% LT/4% ST Debt – 40% Equity
2023	56% LT/4% ST Debt – 40% Equity
2024	56% LT/4% ST Debt – 40% Equity

Hydro One:

Hydro One Inc.	2019	2020	2021	2022	2023
Debt to capitalization ratio[1]	56.7%	55.0%	55.2%	55.1%	56.1%
Equity thickness[2]	43.3%	45.0%	44.8%	44.9%	43.9%

[1]Source: Hydro One Inc. Annual Management's Discussion and Analysis

- 2022 & 2023 pg 1 [link]
- 2020 & 2021 pg 1 [link]
- 2019 pg 1 [link]

[2]100% less Debt to capitalization ratio from preceding row

Hydro Ottawa:

Year	2019	2020	2021	2022	2023
HOL Total Debt (includes short-term and long-term debt) to Equity Ratio*	1.90	1.98	1.92	1.99	1.94
OEB Deemed Capital Structure*	1.50	1.50	1.50	1.50	1.50

*Represented using the OEB LDC scorecard format.

TAB 22

definitely not, like, a 0.8 correlation or something.

So there's a, you know, it's hard. You're used to nine-and-a-half percent, and you just, you know, because I can remember in Alberta in 2013 it went to 8.3 and you could just -- it seems weird, but it was still too high in my opinion, of course. But, you know, it did come down and, you know what, all the utilities maintain their A-ratings and, you know, some had A-minus and they were still able to attract capital at good rates and so on and so forth. The world didn't come crumbling down, it just brought them more in line. Then things change and, you know, the rates change. So...

MS. ANDERSON: Okay. So, you talked about the utilities in the U.S. being higher risk, so there's another why question for you. Why are they higher risk?

DR. CLEARY: Well, it's a great question and of course one I get a lot, obviously, every time I'm involved in these proceedings. Because a lot of those publicly listed ones are holding companies. And I do recognize the same is true for the Canadian holding companies. Right? But also I think the regulatory setup in the U.S., and I'm certainly not an expert on it like some of, you know, the U.S. colleagues involved in these, but I think it's a different kind of scenario than the ones in Canada. I think actually, I can't remember, someone mentioned this morning specific risk to California and Georgia and, you know, like that. Okay. Well, in Canada we could have some jurisdictions like that, but, you know, Ontario is not one of them, Alberta is not one of them. Right? You know, and so, therein lies some of the issues. Right? And I don't think BC is either. So, there's that part of it. And they're in the U.S. capital markets and there's no doubt there's integration of the capital markets.

But the bottom line, and I showed in my evidence is that there's a home bias. In Canada we are 3 percent of the equity market, 3 percent of the fixed income market globally, yet our investors own, average investor in Canada, 42 percent in equity, of Canadian equities. I mean they talk about the -- even the big pension plan is 25 percent and they get criticized for that and say, but actually we're overweight, you know, like a lot. Right? And then the fixed income market is really home bias. It's, like, 84 percent. So, most of the Canadian, you know, if you float bonds in Canada, most likely, and someone mentioned earlier, I think one of the Board members, you know, that when Ontario companies issue bonds, they're over-subscribed. Right? And that's indicating these are pretty high quality bonds. And you ever notice we get that A-rated utility index? That's lower than the A-rated index. Right? That shows you something. It's interesting to note if you actually download the two, it's not a big difference, but it shows you that A-rated utilities are viewed as less risky than just your average A-rated company, and that's because, you know, monopoly, you get to pass through cost to customers, you know, if you're in a strong geographic area, you know, those things

TAB 23

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2024-0063**	**Generic Proceeding - Cost of Capital and Other Matters**
VOLUME:	**5**	
DATE:	**October 2, 2024**	
BEFORE:	**Michael Janigan**	**Presiding Commissioner**
	Lynne Anderson	**Commissioner**
	Pankaj Sardana	**Commissioner**

ask you, Dr. Cleary, and you will know that Commissioner Anderson has been considering how to compare apples to apples in terms of updated information, and she has asked all of the experts. And hopefully not untowardly, I thought I'd put that to you, because I have alerted you to it. And you can address, perhaps just for a minute, whether you can do that kind of an update, as requested of the other experts?

DR. CLEARY: Yes, this is something I could do. Unlike the other experts, I use actual, like where I -- my recommendation is to use actual yields, so as of September 30th or October 31st, if feasible, on 30-year government bonds and A-rated utility spreads, which feed into both my CAPM estimates and my bond yield plus risk premium estimates. So that is something that I could do. My DCF estimate is based on 2023 data, so would require no updating.

MR. MONDROW: And that would -- so I think Commissioner Anderson has been talking about a September 30th date. Would that be something that you could file shortly after September 30th?

DR. CLEARY: Yes. Well, my soft recommendation is to use the most recent, October 31st data, if it was feasible from an implementation process. But the September 30th data is now available, so I believe that by -- hopefully before the time we next resume on September 10th, I could -- or, sorry, October 10th, I could have that completed.

MR. MONDROW: Great. And so we will do that. And I'm happy to throw an undertaking your way Commissioner Anderson, if that would be helpful?

MS. ANDERSON: That would be helpful, to get an undertaking, thanks.

MR. RICHLER: So let's just note that as Undertaking J5.3.

UNDERTAKING J5.3: MR. CLEARY TO UPDATE HIS ROE CALCULTION WITH DATA TO SEPTEMBER 30TH

MR. MONDROW: Thank you, Mr. Richler. My third -- four questions, Dr. Cleary, this relates to a question that was asked of Dr. Pampush, I think it was yesterday, during his direct examination by the OEA's counsel. And he was asked about a phrase taken out of your report, from page 92 of your report, to the effect that your recommended beta estimate of 0.45 is your "usual beta estimate". And that question was put to Dr. Pampush at transcript 4, page 149. And Dr. Pampush's response there was, and I quote:

"This might be an example of a sort of prior thought that should be more supported by data."

Now, could you comment on that characterization, please?

DR. CLEARY: Yes, thank you. I think probably it was meant a priori thought, which means, you know, doing a test where you actually have a -- a hypothesis, if you will, if you want to get technical, about what the outcome will be. And I find it kind of surprising that Nexus disregard -- does not have an a priori let's the data speak for itself, and ignores historical evidence, especially for something like beta estimates, which can be, you know, as low as zero in 2002, as I said on presentation day, and sometimes can be inflated.

So my approach is not to just use the usual, it's well-outlined in Appendix C of my evidence, where I look at the hysterical -- historical, not hysterical. I don't think it's hysterical either -- But the historical data going back many years in Canada. I also cite two US studies that find similar results that US betas never -- approach 1, and that the beta estimates can be unreliable through time.

I use that long-term historical average of .35 for Canadian utility betas in conjunction with the estimates I obtained this time using 2023 data of 0.60 was the average, and I used 0.45, which I believe is an appropriate estimate going forward. It's a forward-looking estimate, but it's based on current data and historical data and professional judgment.

I would also note that, during the Alberta 2023 proceedings, when using the same Canadian utilities, I obtained a beta estimate average of 0.355, which exactly coincided with the long-term historical average. I also used 0.45, and that was recognizing that these beta estimates can vary through time and actually as Nexus did acknowledge today they are using historical data to estimate how the betas are going to be in the future. So, again, applying judgment and to be consistent in my application of the CAPM model for Canadian utilities, I used 0.45 at that time.

MR. MONDROW: Thank you. And, Dr. Cleary, finally, at a big picture level, you have been reading and listening to the oral testimony that has been presented to date. I am wondering if you can characterize the essential difference between the approach you recommend compared to the approaches of the other experts.

DR. CLEARY: Thank you. Yes, so my evidence relies very much on what's going on in the world of finance today and what has gone on for decades. I look at, as a starting point, the expected return on the market and based on historical evidence on long-term estimates of the market-risk premium, which is based on an expected return, and, importantly, on surveys of finance professionals managing trillions of dollars.

For example, that Horizon survey surveys 42 of the largest institutional investors, including the BlackRock, JP Morgan, Goldman Sachs, Vanguard and so on and so forth, and their forecasts are about 6.1 percent, so I believe these are important indicators.

Based on those, which seem low for the future, but that may reflect many factors, and the historical average of 8.5, I feel that 7.5 percent is a reasonable starting point, and I would set that as my ceiling. It's not surprising to me that the utilities experts don't reference -- I don't ever see in their evidence an expected market return, although I have seen them have to forward it on cross-examination of the expected market return because, when they're recommending 11 to 11-1/2 percent for regulated Ontario utilities, then that -- and they have all acknowledged that the average regulated Ontario utility is less risky than the market, that then therefore means that their expected market return estimate -- this is for the long term -- are in the range of 13 to 14 percent, which is just unrealistic, at least in the world of finance that I operate in.

MR. MONDROW: Thank you, Dr. Cleary. Mr. Chair, Dr. Cleary is available for cross-examination.

MR. JANIGAN: Thank you very much, Mr. Mondrow. I believe VECC and Mr. Garner may be up first.

MR. GARNER: I believe Pollution Probe is up first.

MR. JANIGAN: Oh, okay.

MR. GARNER: I look to Ms. O'Connell to guide me through this.

MS. O'CONNELL: Yes, it is. It is Pollution Probe, yes.

MR. JANIGAN: My mistake again. Sorry.

MS. O'CONNELL: Sorry about that.

MR. JANIGAN: Sorry about that, Mr. Garner, and sorry about that, Mr. Brophy. Could you please continue?

MR. BROPHY: It's all right. It's a fast-changing world today.

CROSS-EXAMINATION BY MR. BROPHY

Good afternoon. My name is Michael Brophy, and I am here on behalf of Pollution Probe. I plan to refer to K4.2 first, which is the Pollution Probe compendium which was

TAB 24

ONTARIO ENERGY ASSOCIATION (OEA)

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking:

Tr: 6

To rerun the analysis for each of the proxy groups and for all three approaches, the DCF, the CAPM, and the risk premium, to remove companies with any material amounts of regulated generation.

Response:

Please see J3.2, Attachment 1 for Concentric's ROE analyses, modified to exclude companies that own any material amounts of regulated generation.

As the majority of the companies in Concentric's North American Combined proxy group owned some regulated generation, this reduced the size of proxy groups. For example, the North American Combined proxy group was reduced from 25 to 10 companies. The U.S. Electric proxy group was reduced from 15 to 2 companies. Concentric notes that smaller proxy groups produce results that are less reliable and less statistically robust.

A summary of results, and a comparison to as-filed results, can be found below. These results continue to support Concentric's original recommendation of a 10% ROE.

Three-Model Average	**Canadian**	**U.S. Electric**	**U.S. Gas**	**North American Electric**	**North American Gas**	**North American Combined**
As-Filed Results	9.7%	10.3%	10.0%	10.0%	10.0%	10.1%
# Comps.	*6*	*15*	*4*	*19*	*8*	*25*
J3.2 Results*	9.9%	10.1%	10.0%	9.7%	10.1%	10.0%
# Comps.	*4*	*2*	*4*	*4*	*7*	*10*

** Excludes companies owning generation assets (i.e., integrated electric companies)*

ONTARIO ENERGY ASSOCIATION (OEA)

Answer to Undertaking from
Consumers Council of Canada (CCC)

Undertaking:

Tr: 33

Similar to undertaking J3.2, to rerun the analysis to exclude also companies in the peer group that own material amounts of regulated generation and/or derive 10 percent or more of their operating income from unregulated operations.

Response:

Please see J4.2, Attachment 1 for Concentric's ROE analyses, modified to exclude companies that own regulated generation, as well as companies with more than 10% of operating income from unregulated operations.

As with the analysis developed for J3.2, the two criteria for exclusion reduce the sizes of the proxy groups significantly. For example, the Canadian and U.S. Electric proxy groups were left with only two companies. The North American Combined proxy group only had seven companies. Concentric notes that using smaller proxy groups produces less statistically reliable results, and runs contrary to the recent BCUC and AUC decisions that include these companies.

A summary of results, and a comparison to as-filed results, can be found below:

Three-Model Average	**Canadian**	**U.S. Electric**	**U.S. Gas**	**North American Electric**	**North American Gas**	**North American Combined**
As-Filed Results	9.7%	10.3%	10.0%	10.0%	10.0%	10.1%
# Comps.	*6*	*15*	*4*	*19*	*8*	*25*
J4.2 Results*	9.2%	10.1%	9.8%	9.7%	9.8%	9.7%
# Comps.	*2*	*2*	*3*	*4*	*4*	*7*

** Excludes companies owning generation assets (i.e., integrated electric companies), as well as companies with more than 10% of operating income from unregulated operations.*