ONTARIO ENERGY BOARD

2024 REVIEW OF COST OF CAPITAL PARAMETERS AND DEEMED CAPITAL STRUCTURE

EB-2024-0063

**Evidence
of
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Professor of Finance**

Sponsored by Industrial Gas Users Association (IGUA) and

Association of Major Power Consumers in Ontario (AMPCO)

July 19, 2024

TABLE OF CONTENTS 1

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

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

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 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)	• The recent risk assessments have considered business risks	• The risk factors considered in recent equity thickness proceedings are	**Maintain the OEB's current policy of reviewing business and financial risk factors if**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
	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?	(energy transition risk, volumetric risk, operational risk, regulatory risk, and policy risk) and financial risk. • The OEB undertakes a full reassessment of a utility's capital structure in the event of significant changes in risks.	sufficient. Business risk assessment can be performed based on changes in volumetric risk, operational risk, regulatory risk and policy risk (including energy transition risk). 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.	**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.	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	**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**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
			business/financial risks (including regulatory risk) is a reasonable approach, which LEI recommends be retained. • In addition, LEI recommends proactive impact assessments ("IAs") before material regulatory changes.	**that proactive impact assessments should occur following 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**

Issue #	**Issue**	**Status Quo**	**LEI**	**Dr. Cleary**
				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.
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	**- 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**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
			considering the spread over LCBF for an A-rated utility. • DLTDR applied as a cap for all utilities.	**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.**
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.	• 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	**Maintain the existing ERP formula methodology, but make the following modifications:** **1. Update the base ROE to 7.05%.**

Issue #	Issue	Status Quo	LEI	Dr. Cleary
		• The ROE is updated annually using adjustment factors for long Canada bond forecast (“LCBF”) and A-rated utility bond yield spread.	10.22%), as it meets the FRS. • 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).	**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):** $ROE_t = 7.05\% + 0.75 \times (LCBF_t – 3.30\%) + 0.75 \times$

Issue #	**Issue**	**Status Quo**	**LEI**	**Dr. Cleary**
				(UtilBondSpread$_t$ – 1.38%)
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	While the capital structure for transmitters is determined on a	• 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**
	structure for electricity transmitters depending on whether they are a single versus multiple asset transmitter?	case by case basis, 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 regarding the extent to which the cost of	**- 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
			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 material (100 bps or more).	**I support maintaining the current OEB approach, but also incorporating the additional option recommended by LEI.**
G. Other issues (prescribed interest rates)				

Issue #	Issue	Status Quo	LEI	Dr. Cleary
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 current approach of basing the prescribed interest rate on the FTSE Canada Mid Term Bond Index All	**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
			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

Issue 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.)?*

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

[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.

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.

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:

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

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.

[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.

<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 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 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.

<u>LEI's CAPM Analysis:</u>

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

[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.

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.

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

[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.

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.

My Base ROE Analysis and Recommendations:

Context:

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

[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.

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% 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.

[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.

[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%.

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.

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.
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)

[14] This is consistent with the approach used by LEI in its evidence, with final beta estimates determined based on raw beta estimates.

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 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:

[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.

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

[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.

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.

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 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.

[17] OEB. *2024 Cost of Capital Parameters.* October 31, 2023.

- 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)

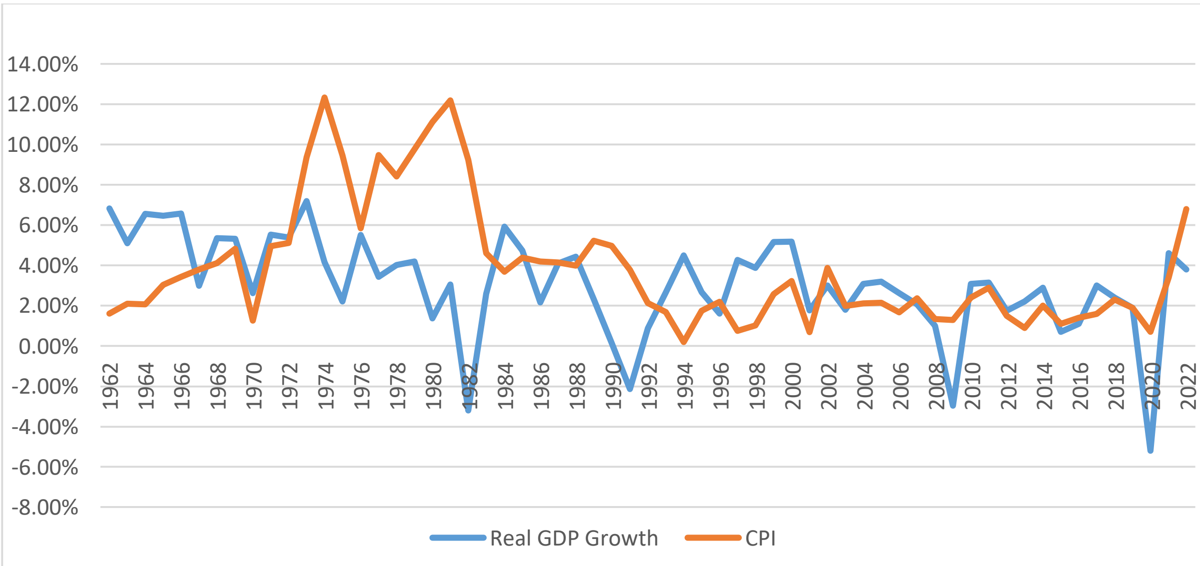
4.1 The Past and Present

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.

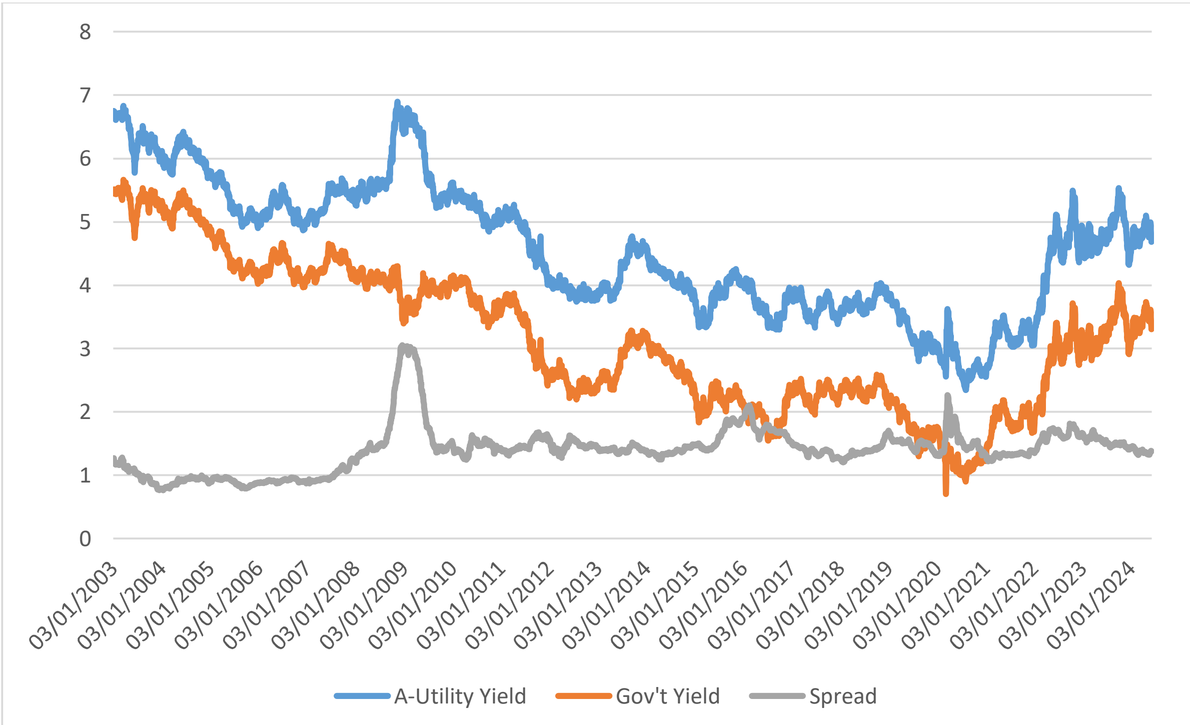
The 1962-2022 statistics are obviously driven by the high rates of inflation during the 1970s and 1980s. With the exception of 2022, where inflation hit 6.8%, rates have generally been within the Bank of Canada's 1% to 3% target range since the policy's adoption in 1991, being in line with the 2% target 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)

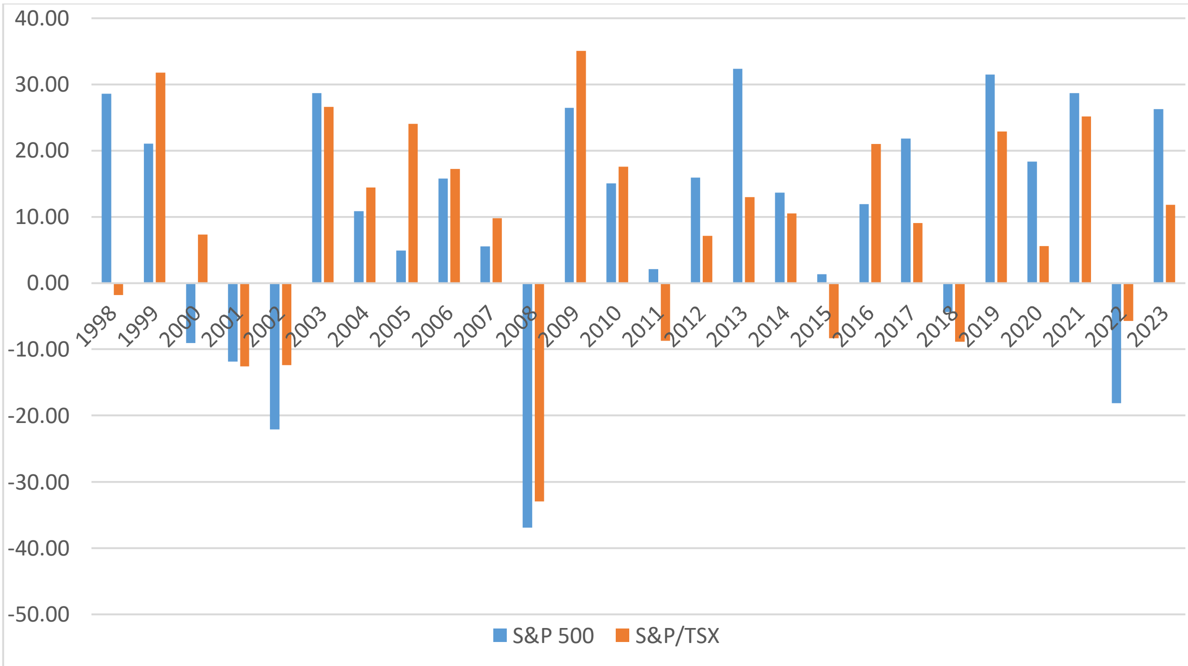


Source: Bloomberg.

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

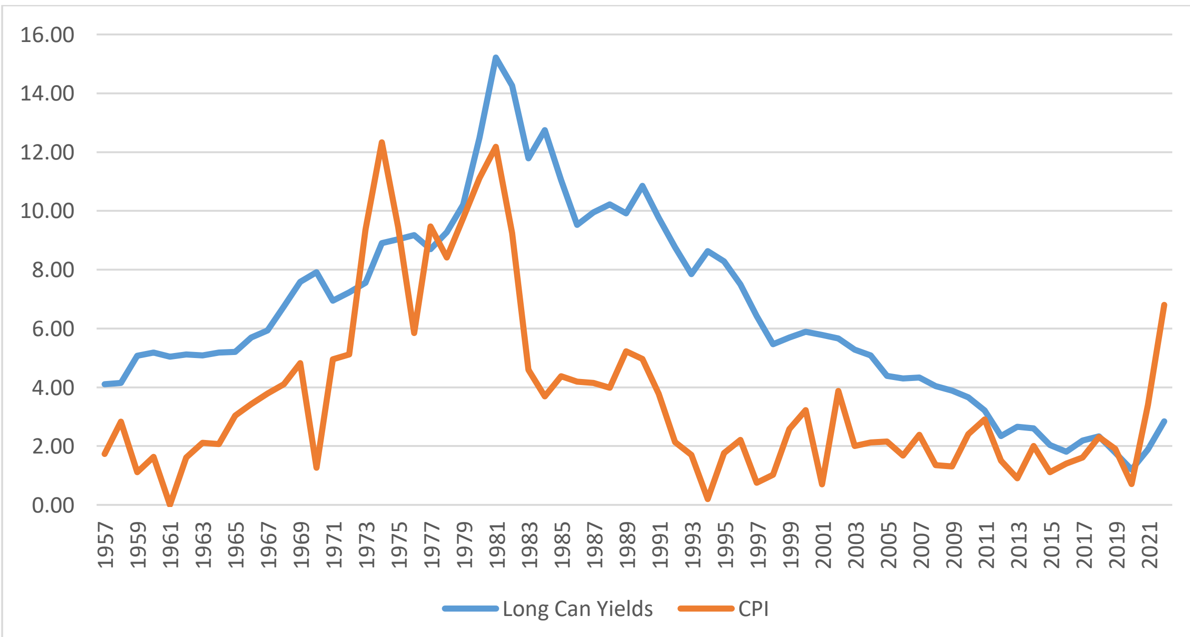
4.3.1 Debt Markets

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)

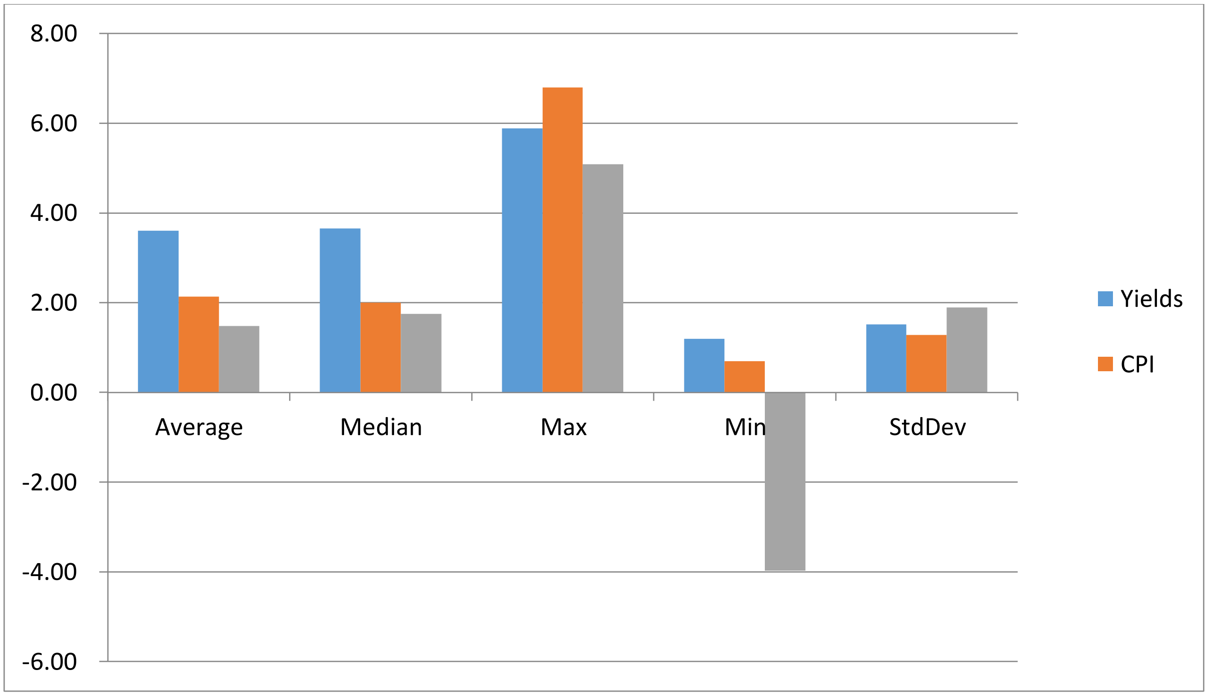


Data Source: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010012201#timeframe

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)

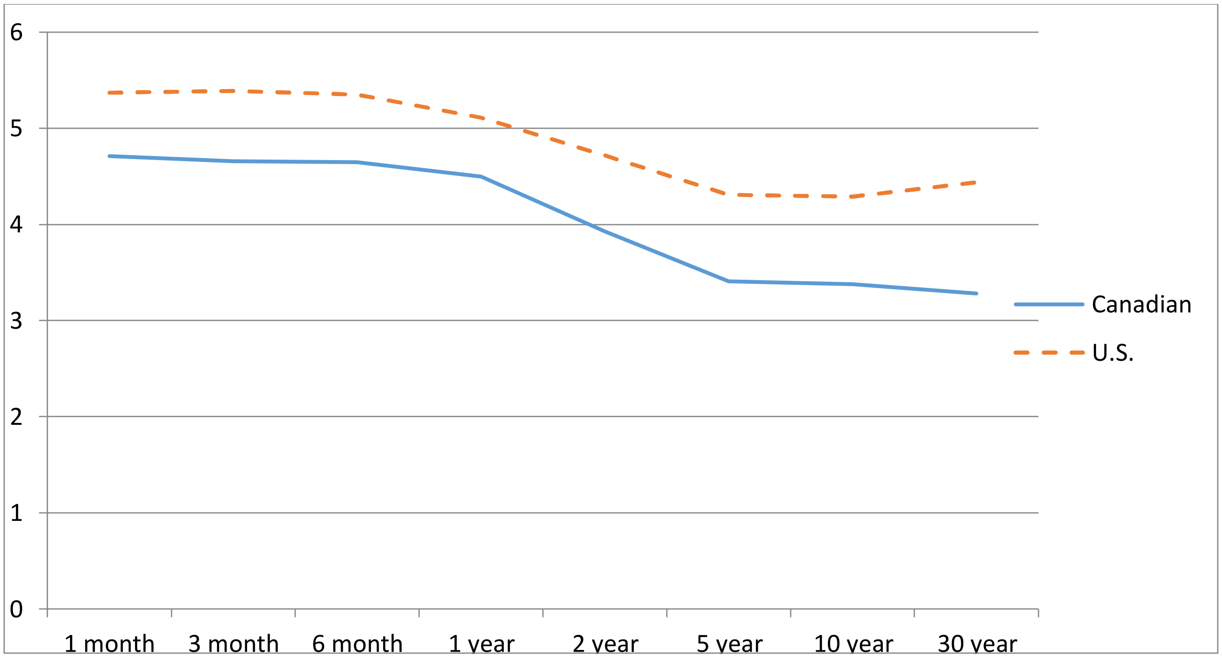


Data Source: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010012201#timeframe

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.

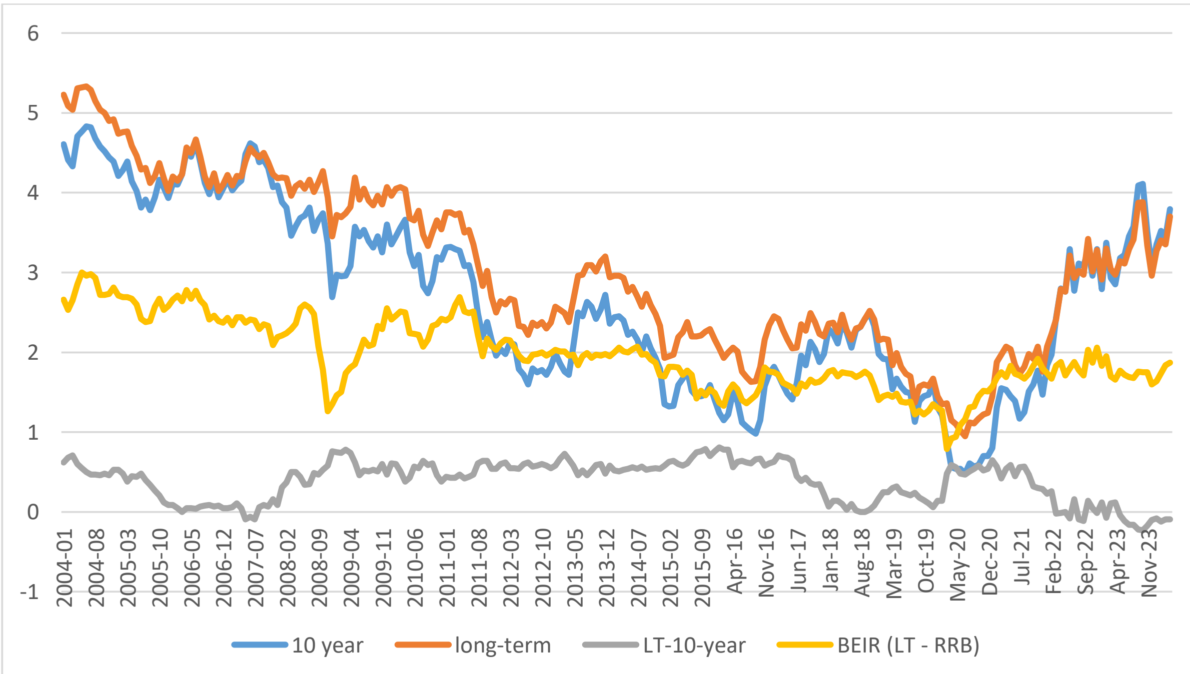
4.3.2 Interest Rate Levels

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, the fact that allowed ROEs have not decreased in North American jurisdictions (including

[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%.

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)

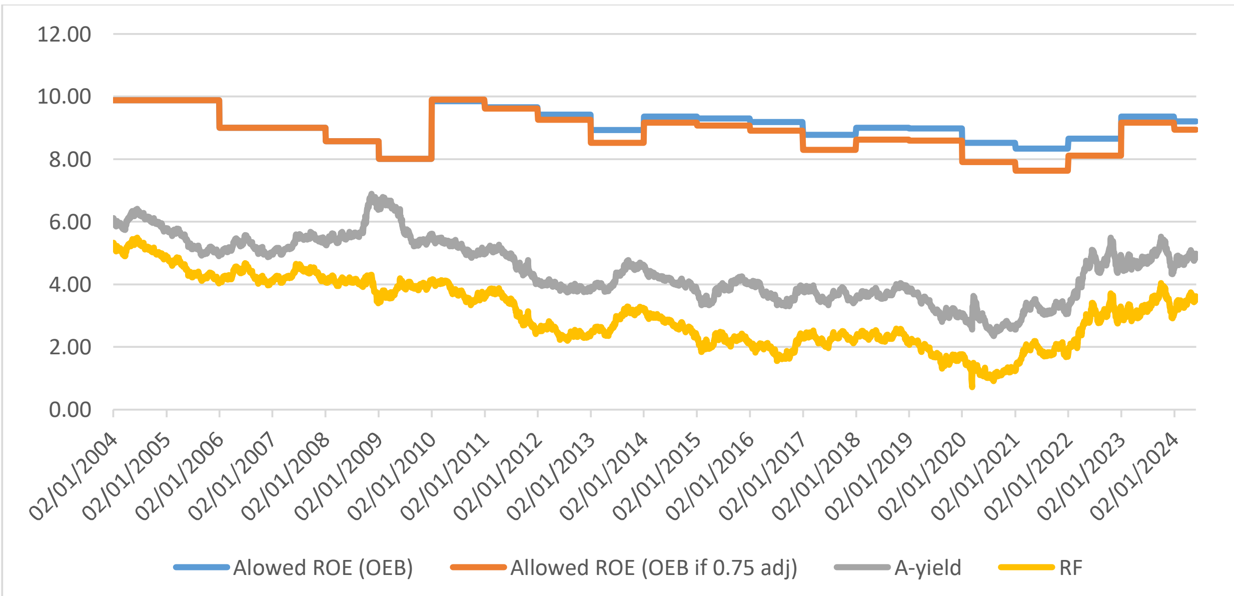
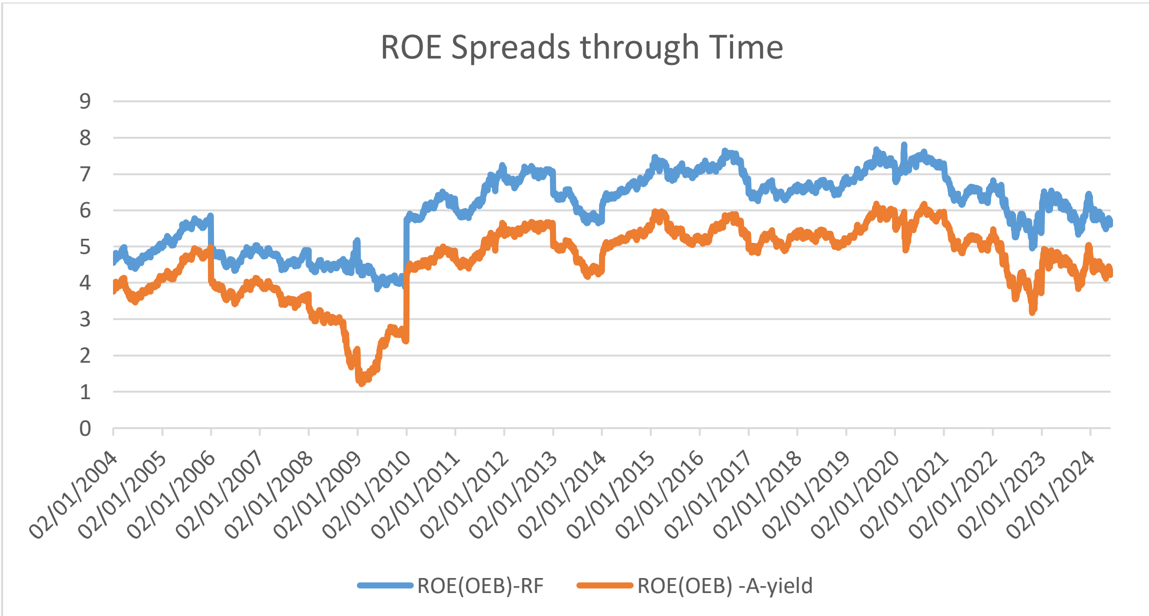


FIGURE 10

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]

[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.

- 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).

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

[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.
[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.

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**.

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 "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				

[34] Decision 22570-D01-2018, 2018 Generic Cost of Capital, page 97, para. 460.
[35] Appended to this evidence as Attachment AW.
[36] Appended to this evidence as Attachment AX.

Source	**Horizon**	**Canada**	**U.S.**	**World / Developed Markets (excl. U.S.)**
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_1057ff4efa7244d6bb7b1a8fb88236e6.pdf[38]	Intermed. (<10 years) Long-term (10-years or more)		U.S. Large Cap (Nominal) 6.90% (4.8-10.2%) 7.37% (5.6-10.2%)	Non-US Dev. Mkts. 7.49% (4.7-10.3%) 7.78% (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

[37] Appended to this evidence as Attachment AY.
[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).

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.

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.

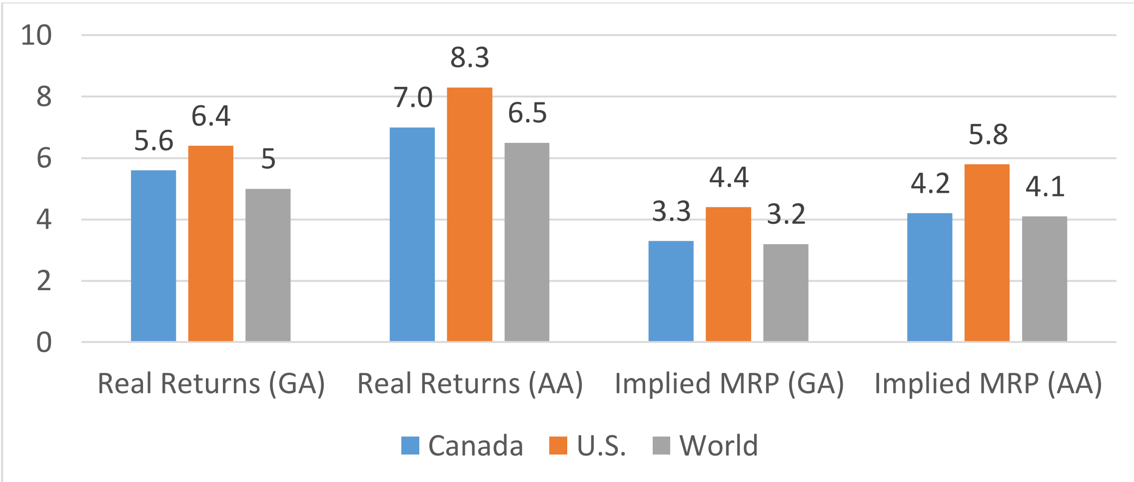
I believe that both historical returns and current expectations of market professionals represent the best sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table 7 and discussed above suggests a range 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 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.

[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 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

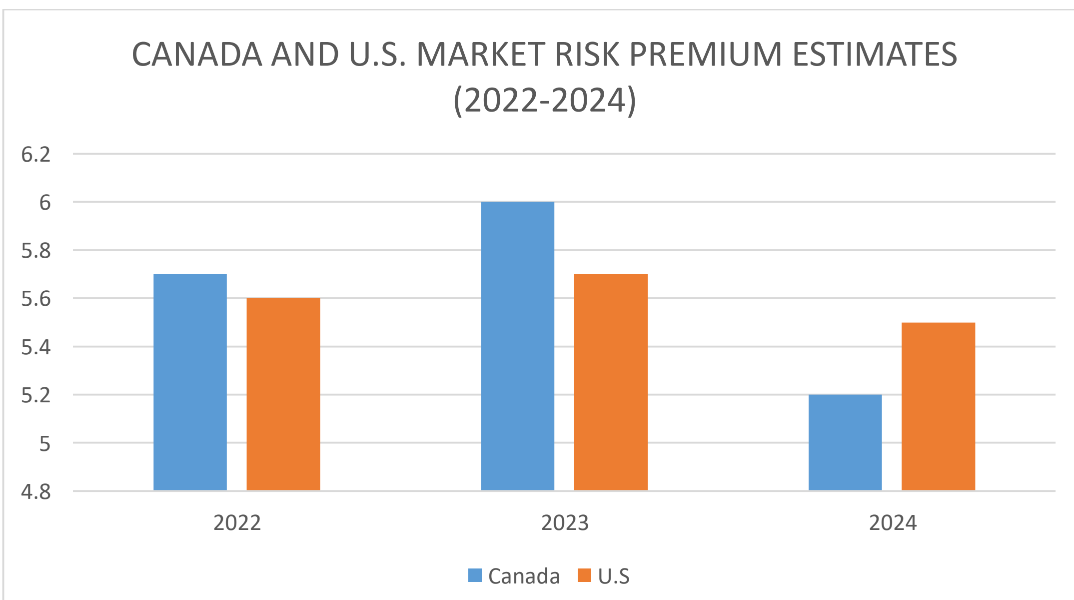
CANADA, U.S. AND GLOBAL MARKET RISK PREMIUMS (1900-2015)



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:

> 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

[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.

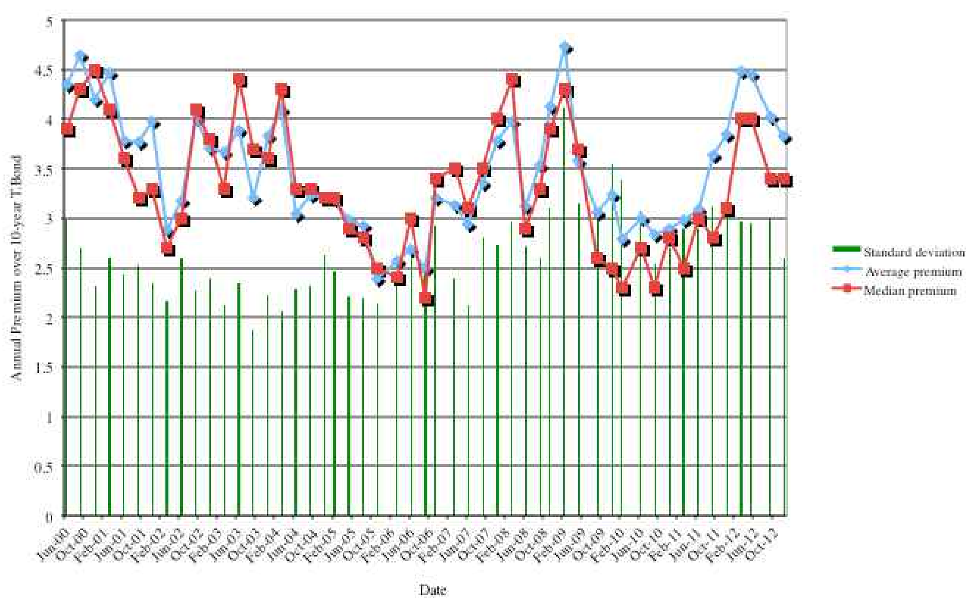
> instance, Merrill reported an average equity risk premium of 3.5% from the survey, but that number jumped to 4.1% by March, after a market downturn. As markets settled down in 2009, the survey premium has also settled back to 3.76% in January 2010. Through much of 2010, the survey premium stayed in 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



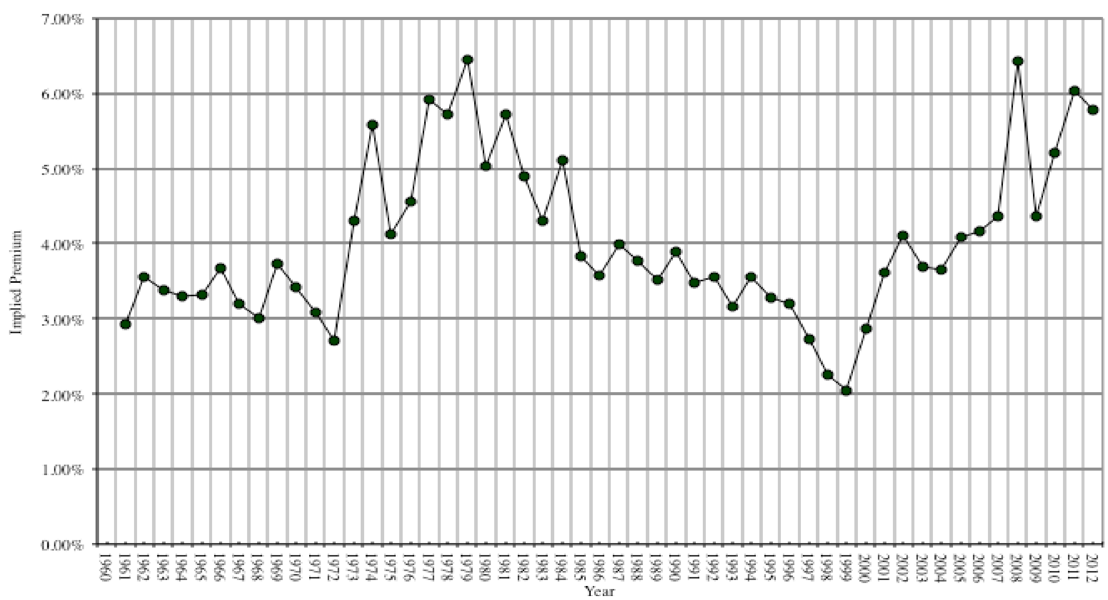
> Note the survey premium peak was in February 2009, right after the crisis, at 4.74% and had its lowest recording (2.47%) in September 2006. The average across all 13 years of surveys (about 9000 responses) was 3.53%.[49]

[48] *Ibid.,* pages 18-19.
[49] *Ibid.,* pages 20-21.

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).

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

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[50] *Ibid.,* page 74.

> 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 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

[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.

> 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.**
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:

[54] *Ibid.,* pages 14-15.

[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).

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 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

[56] This is consistent with the approach used by LEI in its evidence, with final beta estimates determined based on raw beta estimates.
[57] The working papers for Table 8 are appended as Attachment I to my evidence.

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.

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%**.

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

[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.

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:

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

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:

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

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 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.

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[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.

[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.

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.

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

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[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].

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.

TABLE 11

DCF GROWTH AND SINGLE STAGE DDM ESTIMATES

1	**2** **Implied g (2023)**	**3** **Implied g (17-23)**	**4** **Implied Ke (2023 g and 2023 DY)**	**5** **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: $Ke = (D_0/Price)\times(1 + g) + g$.

[63] Individual company growth estimates were as high as 15.3%, which is clearly an even more unreasonable long-term growth expectation.

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]

[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.

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

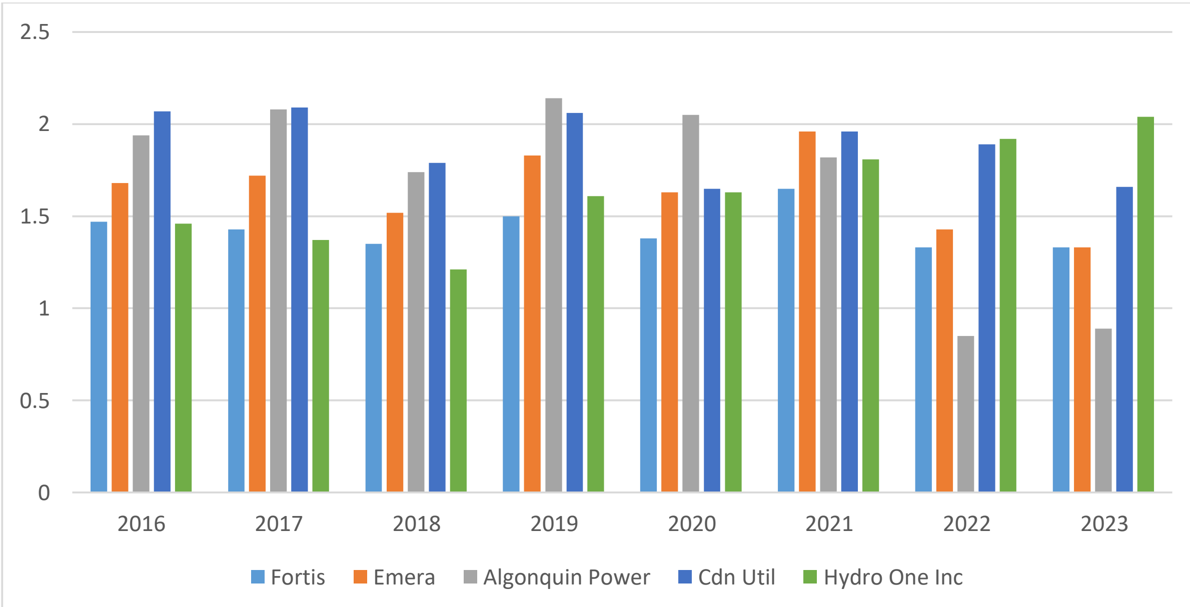
Table 10 reported a 2023 average ROE for the 5 Canadian utilities in the Canadian sample of 7.76%, with a 2017-2023 average of 8.51%. These averages are well below the 2024 allowed ROE for regulated Ontario utilities of 9.21%. The allowed ROE is higher than those for the Canadian sample of publicly listed 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.

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.

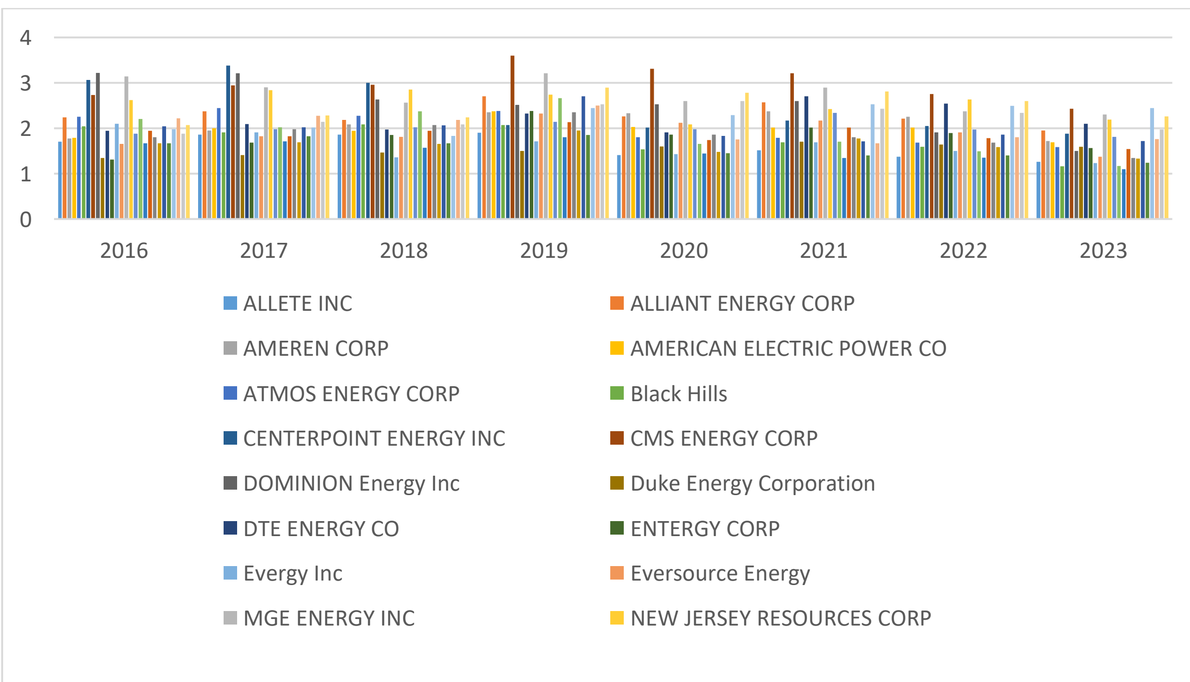
FIGURE 13

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] $P/B = (ROE - g) / (Ke - g)$

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

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

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 decades and double digit “nominal” returns are no longer the norm for stocks, given existing

[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.

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**

---

[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.

> 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 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

[75] Appended to my evidence as Attachment BI.

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 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

[76] See: Hydro One Ltd. Upgraded To 'A' On Improved Govern | S&P Global Ratings (spglobal.com).

comfortably satisfies the third leg of the fair return standard. In other words, HOI's risk profile 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.

Clearly, HOI's credit metrics are very strong, with two of them consistently falling in DBRS' A range, and with one consistently falling in the AA category. This is reflected in HOI's ability to attract debt capital at attractive rates, as discussed in Section 5.2.2. This would continue to be the case if its equity ratio was lowered to 38%, which would bring it in line with that for EG, and closer to the 37% allowed equity ratio for similar risk utilities in Alberta (like Fortis Alberta Inc. whose bonds have virtually the same yield as those on HOI's bonds, as noted above). I would also note the evidence through which I have shown that the average "market-determined" P/B ratio for Canadian publicly traded utilities was 1.45 as of 2023, while HOL had a P/B ratio of 2.04, which suggests the market feels that it is comfortably earning a more than an adequate return based on its current equity base, as discussed in Section 5.5.

In other words, there is no reason that HOI's equity ratio could not be lowered to as low as 36% and still allow it to borrow and issue equity at attractive rates, as well as maintain solid credit metrics. However, in the interest of gradualism, and also to remain in line with EG's current allowed equity ratio of 38% (although I believe 36% would be more appropriate as discussed in Section 6.1), 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.

APPENDIX A

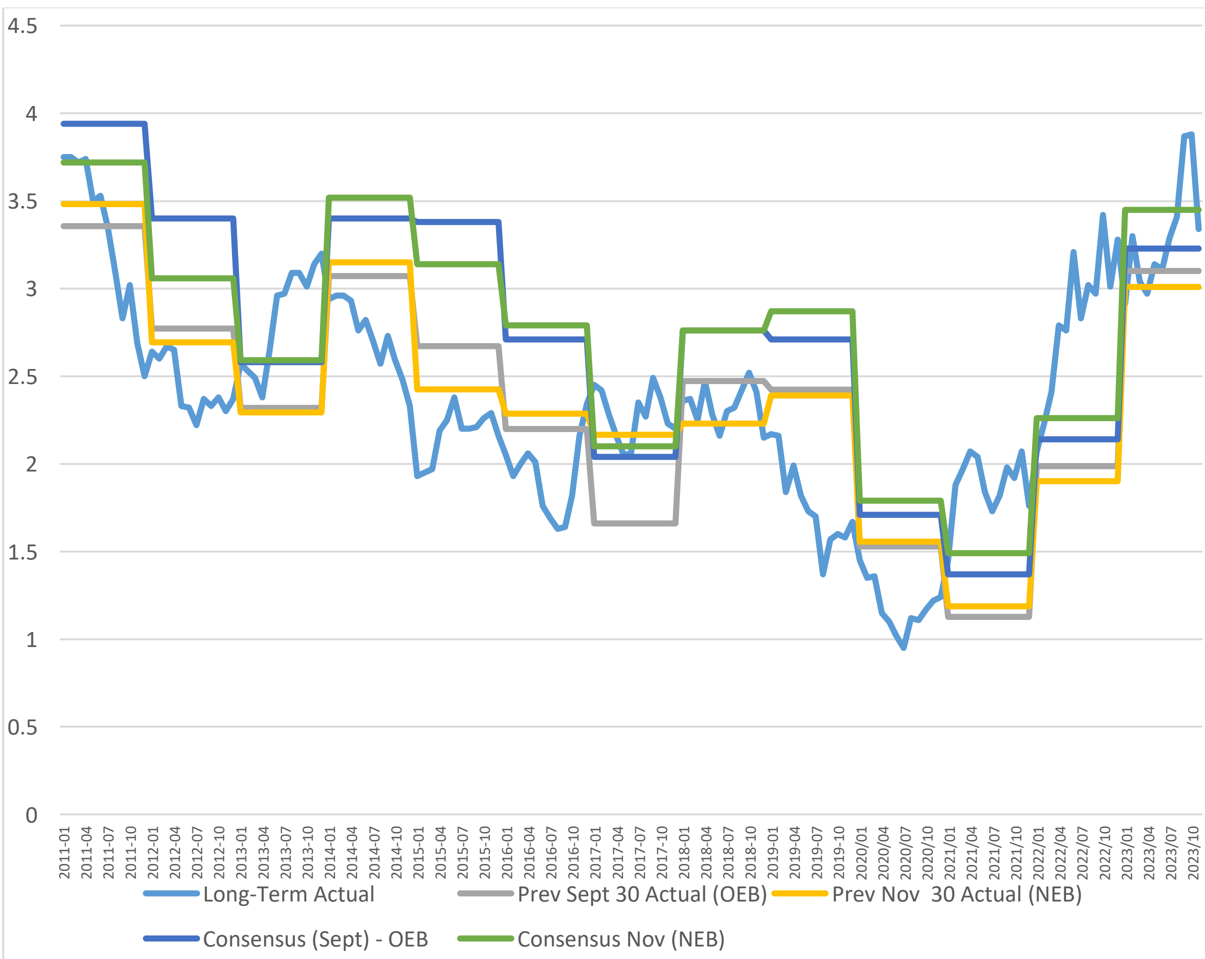
Using Actual Yields versus Economists' Forecasts

The 30-year Government of Canada bond yield as of June 5, 2024 was 3.30%, while the 10-year yield was 3.39%. I have consistently argued (during Alberta Utility Commission (AUC) GCOC Proceedings in 2016, 2018, 2021 and 2023) that using Consensus yield forecasts as a proxy for future 30-year Canada yields has led to an **upward bias** relative to the subsequent actual yields that prevail. This bias disappears when we simply use the prevailing 30-year rate as close as possible to the start of the period – for example using the actual yield on September 30th or November 30th - as the risk-free rate for the upcoming year. 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. In addition to the inaccuracy associated with 10-year yield forecasts, the use of Consensus 10-year yield forecasts is simply the starting point. This is because we must then obtain another "estimate" – i.e., the spread between 10 and 30-year yields, which varies through time, and hence is also subject to estimation errors. For example, while this spread averaged +0.40% 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.

In this Appendix I pick up on the points made above and examine the forecasting ability of Consensus forecasts at the beginning of test periods, versus simply using actual prevailing long-term government yields. In particular, I compare the actual prevailing 30-year government bond yields to forecasts of these yields obtained using adjusted Consensus forecasts from September in the previous year (as used by the OEB) and from November of the previous year (as previously used by the National Energy Board (NEB)). I consider forecasts based on using RF forecasts based on the actual long-term government yields as of September 30th and November 30th in the previous calendar year. Figure A1.1 depicts the results of this analysis using data over the 2011-2023 period. Figure A1.1 demonstrates clearly that both the September (OEB) and November (NEB) Consensus yield forecasts were consistently much higher than the actual prevailing rates during the subsequent test periods. For example, while the average actual 30-year government yield over the period was 2.57%, the average September (November) Consensus forecasts was 0.37% (0.38%) higher at 2.94% (2.95%). 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 (November 30th) yields was 2.58% (2.57%) – virtually the same as the average for the actual prevailing yields of 2.57%. Table A1.1 shows that using Consensus forecasts would have added an average excess allowed ROE of 0.4% (borne by the consumer), when used in the OEB formula (and also in terms of CAPM cost of equity estimates), whereas using actual prevailing RF rates would have been unbiased on average. The working papers for Figure A1.1 and Table A1.1, below, are appended as Attachment N to my evidence.

FIGURE A1.1

LONG-TERM CANADA BOND YIELDS VERSUS FORECASTS (2011-2023)



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

In order to examine the statistical significance of the differences in forecasting accuracy, I estimate the mean squared error (MSE) of forecasts and present them in Table A1.1. This analysis shows that the MSE for September and November Consensus forecasts are 0.509 and 0.445 respectively. These MSEs are close to double the corresponding MSE estimates using previous September and November actual yields (i.e., 0.272 and 0.241). The t-tests provided in Table A1.1 show that the differences in MSE estimates are statistically significant when comparing those determined using actual yields to Consensus forecasts, but the differences are insignificant between using September and November actuals, and between using September and November Consensus forecasts. In other words, using beginning of test period actual long-term government rates as a forecast for future RF values would provide statistically significantly better forecasts of long-term government yields. I revisit this evidence in Section 5.2 of my evidence when I discuss my RF estimate for the CAPM.

TABLE A1.1

STATISTICS FOR LONG-TERM CANADA BOND YIELD FORECASTS (2011-2023)

	Difference using Sept. 30 Actual Yields	**Difference using Nov. 30 Actual Yields**	**Difference using September Consensus Forecast**	**Difference using November Consensus Forecast**
Average	**-0.015**	**0.002**	**-0.369**	**-0.377**
Median	-0.151	-0.066	-0.440	-0.470
Max	1.432	1.518	1.280	1.160
Min	-1.052	-1.020	-1.450	-1.500
StdDev	0.523	0.492	0.612	0.552
Mean Squared Error (MSE)	0.272	0.241	0.509	0.445
t-tests (MSE vs Consensus OEB)	**-4.292*****	**-4.883*****		
t-tests (MSE vs Consensus NEB)	**-5.356*****	**-5.878*****	1.295	
t-tests (MSE Actual Sept vs Actual Nov)	0.877			

*** indicates statistically significant at the 1% level

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

The fact that using existing rates would have worked much, much better than using Consensus forecasts over the 2011-2023 period is well-supported by academic studies. For example, a study by Hafer and Hein (1989)[79] 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). In particular, this study shows that naïve forecasts perform the best under one of their measures of accuracy, while using interest rate futures performs best under their other measure of forecasting accuracy. Economic forecasters, on the other hand, perform worst under both measures of forecast accuracy. Similarly, a 2005 study by Mitchel and Pearce (2007)[80] examined the six-month-ahead forecasts of Treasury bill and Treasury bond rates from 1982 to 2002. This study 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."[81] Yet another study by Spiwoks, Bedke and Hein (2008)[82] examined 10-year US government bond yield and three-month US Treasury bill rate forecast accuracy for the 1989 to 2004 period. They found 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 even in 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."

[79] This article is appended to my evidence as Attachment AA.
[80] This article is appended to my evidence as Attachment AB.
[81] The random walk model is equivalent to using naïve forecasts, as defined above.
[82] This article is appended to my evidence as Attachment AC.

APPENDIX B

Comparing the Risk of Enbridge Gas (EG) to U.S. Utilities

[This Appendix reproduces the analysis included in Sections 4.1 and 4.2 (pages 15-20) of my 2023 evidence prepared for the Enbridge Gas rebasing application (EB-2022-0200, Exhibit M6].

4.1 Business Risk

Section 3 shows that EG possesses very low business risk, which is seen as its number one strength by debt rating agencies. The same can likely be said for most other Canadian regulated utilities that operate in supportive regulatory environments, and in fact my written evidence provided in the current Alberta GCOC Proceedings confirms this to be the case for Alberta operating utilities as well. Certainly, it is easy to see that such regulated utilities have very low business risk when compared to companies operating in other industries that are non-regulated, 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.

4.2 Comparing the Risk of EG to US Utilities

While EG has a debt rating of A from DBRS and an A- rating from S&P, Attachment 1 included in the response to IGUA54 of Attachment I.5.3 shows that only four of the eight companies included in the US HoldCo proxy group have S&P debt ratings of A- or higher (i.e., Northwest at A+, and Atmos, ONE Gas and Spire all at A-). Three of the other four have lower ratings that range from BBB- (Southwest Gas), to BBB (South Jersey Industries), and to BBB+ (NiSource), while the fourth does not have an S&P rating. This suggests there may be potential issues regarding the comparability of this proxy group as being of "similar risk" to EG, which I explore further below.

The purpose of the analysis in this section is to provide quantitative evidence comparing the risk of US utilities that are included in Concentric's US OpCO and US HoldCo proxy groups to that of EG. In particular, the evidence provided by Concentric relies heavily on two US proxy groups based on the premise that such samples are of comparable risk to EG, and therefore implies there is no need to make adjustments for comparison purposes. While US utilities may not be high business risk firms relative to US firms in other industries, they clearly have more risk than EG. 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.

One effective way to compare overall riskiness of EG to its proposed US counterparts would be to compare their ability to earn their allowed ROEs, as I did for EG (and UG) in Table 1. Recall that EG earned ROEs above the allowed ROEs for 33 straight years from 1990 to 2022, and that over the entire period it earned ROEs that exceeded allowed ROEs by an annual average (median) of **1.09%** (1.10%). This is **bottom line empirical evidence** that EG has low risk.

Concentric did not provide evidence regarding earned versus allowed ROEs for the utilities it included in its four proxy groups in response to IGUA-50(b) as had been requested. And unfortunately, it is not practical within the budget available for me to undertake a comprehensive comparison of the earned ROEs to allowed ROEs for the US utilities included in Concentric's proxy groups. I would also note that the eight US utilities included in Concentric's US Hold Co group are holding companies that own several distinct operating utilities, which operate in numerous jurisdictions. Fortunately, I can point to two other sources that did conduct such analyses of broader samples of US utilities, both of which provide strong evidence that, unlike EG (and UG), **the average U.S. utility earns well below their allowed ROE!**

For example, a recent Oliver Wyman report on North American utilities suggested that the "average utility **does not earn its allowed return on equity**."[83] Even stronger support for this conclusion can be found in an empirical study by Azgad-Tromer and Talley (2017). This study examined allowed ROEs versus actual ROEs using observations from all 50 states as well as four Canadian provinces over the 2005-2016 period.[84] The study contained predominantly U.S. observations, with only 18 of the 544 observations being from Canada. Hence their finding that "awarded ROEs appear to overshoot realized ROEs by between 1.5 and 1.75 percent…" can be seen as a strong indication that U.S. utilities do not on average earn their awarded ROE. In fact, it seems they significantly fall short of doing so, with average (median) **under-performance of 1.79% (1.45%)** according to Figure 4 of their study. This

[83] Source: Page 10 of "North America Utilities: Still a Smart Bet for the New Grid," Oliver Wyman, 2015. Appended to my evidence as Attachment BL.

[84] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://www.semanticscholar.org/paper/The-Utility-of-Finance-Azgad-Tromer-Talley/c5913d92dc6600974956b13c9383bee6f61b731b).

contrasts significantly with the evidence for EG provided in Table 1, which showed that EG earned well above (i.e., approximately **1.1%** on average) their awarded ROEs over the 1990-2022 period, and **never earned below it** – not even in one out of 33 years. Clearly, it is inappropriate to compare the two groups of utility firms, which amounts to comparing apples to oranges.

Aside from referencing these sources of evidence regarding US utilities' inability to earn their awarded ROE, another effective way of comparing the riskiness of EG to that of the US utility proxy groups is to compare the volatility in earned ROEs. ROE volatility is a measure of total risk (i.e., business and financial risk), since business risk influences operating income volatility while financial leverage influences net income volatility. I will use the coefficient of variation of the earned ROEs (i.e., CV(ROE)), described in footnote 4 as my ROE volatility measure, and will compare the CV(ROE) for the US HoldCo sample over the 2013-22 period[85] to the ones calculated for EG (and UG), which were reported in Table 1.[86]

Table 2 provides the summary statistics for earned ROEs for the US HoldCo sample over the 2013-2022 period, similar to those provided for EG and UG in Table 1 over the 1990-2022 and 1990-2018 periods. Table 2 shows that the reported ROEs for the US utilities averaged 8.41% over the 2013-22 period, with a median of 9.25%. While not reported in Table 1, the 2013-22 average (median) reported ROE for EG was 9.89% (10.05%), while the 2013-2018 average (median) reported ROE for UG was 9.89% (9.77%). If we look at the last column in Table 2 and compare the coefficient of variation of the earned ROEs (i.e., CV(ROE)) for the US sample to the results reported in Table 1 for EG and UG, we can see that the US utilities displayed much greater volatility in ROEs than both EG and UG. In particular, the average CV(ROE) across all of the US utilities over the 2013-22 period was **0.446**, which is **more than three times larger** than the 1990-2022 average for EG of 0.133, and the 1990-2018 average for UG of 0.155 that are reported in Table 1. While not reported in Table 1, if we look at the same time period used for constructing the US HoldCo results, we find that the 2013-2022 average CV(ROE) for EG was much lower at **0.069**, while the 2013-2018 average for UG was

[85] Data was only available for most companies as far back as 2013, so I could not find reliable data for previous years.
[86] I was forced to focus solely on Concentric's US HoldCo sample since this data is accessible with a reasonable level of effort, whereas the ROE earned data for companies in the US OpCo would be extremely time consuming to locate. Further, and as mentioned by Concentric in its response to IGUA-50(b) "calculating earned ROEs from accounting data is complicated by the many common adjustments made for regulatory accounting purposes."

also much lower at **0.069** – both being **less than one-sixth the US average**. The working papers for Table 2 are appended to my evidence as Attachment E.

TABLE 2

SUMMARY STATISTICS – US REPORTED ROEs (2013-2022)

Utility	Average	Median	Max	Min	StDev	CV(ROE)
Atmos Energy Corp	10.29%	9.93%	13.90%	8.94%	1.42%	0.138
New Jersey Resources Corp	13.20%	12.54%	17.58%	6.78%	3.41%	0.258
NiSource Inc.	6.24%	7.48%	13.11%	-1.46%	4.86%	0.780
Northwest Natural Holding Company	6.48%	7.94%	8.75%	-6.98%	4.77%	0.736
ONE Gas Inc	8.26%	8.54%	9.01%	6.55%	0.87%	0.105
South Jersey Industries Inc.	7.15%	10.18%	11.03%	-0.32%	4.34%	0.607
Southwest Gas Corporation	7.71%	8.98%	11.15%	-6.76%	5.20%	0.674
Spire Inc	7.94%	8.42%	10.82%	3.22%	2.14%	0.270
	Average	**Median**	**Max**	**Min**	**StDev**	**CV(ROE)**
Average	**8.41%**	9.25%	11.92%	1.25%	3.38%	**0.446**
Median	7.82%	8.76%	11.09%	1.45%	3.87%	0.438
Max	13.20%	12.54%	17.58%	8.94%	5.20%	0.780
Min	6.24%	7.48%	8.75%	-6.98%	0.87%	0.105
StDev	2.31%	1.62%	2.89%	6.13%	1.69%	0.280

Date Source: www.morningstar.ca

The ROE analysis above shows clearly that the utilities included in the US HoldCo sample possess greater risk than EG. This is hardly surprising given that this sample is comprised of holding companies with various ownership structures and a variety of exposures to risks to which EG is not exposed – at least not to the same extent.

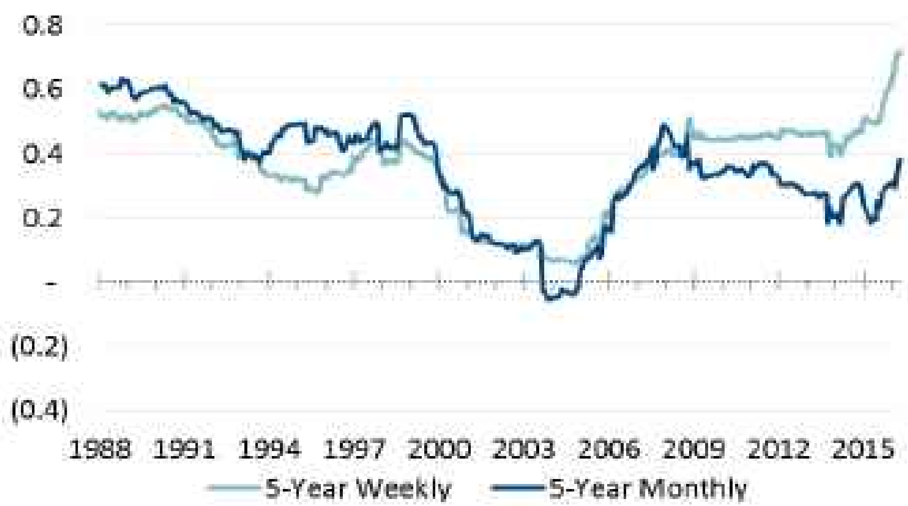
APPENDIX C

Beta Estimation

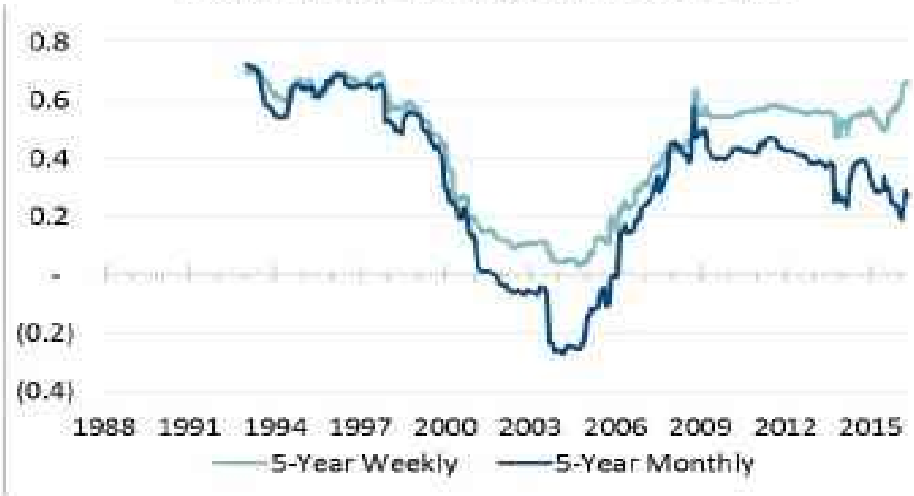
In order to apply the CAPM, we require beta estimates. I copy below two figures and relate some of the discussion from previous Alberta GCOC proceedings, that discusses historical beta estimates:

1. I make reference to Figure 6 at page 45 of Dr. Villadsen's rebuttal evidence in the 2016 Alberta GCOC proceedings (Attachment 20622-X0457), which was referenced in VILLADSEN-UCA-16 2017NOV21-014, and is reproduced below. It depicts 5-year rolling monthly and weekly beta estimates calculated (1) over the 1988-April 2016 period for Dr. Booth's sample of Major Canadian Utility Holding Companies (Panel A); and, (2) over the 1992-April 2016 period for the Utility Sub Index for the S&P TSX (Panel B).

Figure 6: Comparison of Historic 5-Year Monthly and Weekly Betas[136]
Panel A: Simple Average of Booth's Major Canadian Utility Holding Companies



Panel B: Utility Sub Index for the S&P TSX



Source: BV Workpaper R06.

The average beta estimate over the 28-year 1988-2016 period in Panel A (for Dr. Booth's sample) is **0.35**, while the maximum is 0.63, and the minimum is -0.05. The average beta estimate over the 25-year period in Panel B (for the Utility Sub-Index) is **0.32** for the TSX sample and **0.31** for the Booth sample, while the maximum is 0.72 for the TSX sample and 0.52 for the Booth sample, and the minimums are -0.27 (TSX sample) and -0.05 (Booth sample). The graphs make it very clear that nowhere during this entire period do the beta estimates even come close to 1.0 (i.e., the Booth sample never has a beta estimate exceeding 0.63, while the TSX sample never has a beta estimate exceeding 0.72). This long-term evidence strongly refutes using betas that are adjusted toward one, given long-term average betas in the 0.31-0.35 range, with beta estimates never exceeding 0.63-0.72. Clearly, such an adjustment of beta estimates towards one makes no intuitive sense, since they have never even come close to 1.0 in practice.[87]

2. I next turn to the evidence provided by Mr. Hevert in the 2018 Alberta GCOC proceedings. Chart 20 and Chart 21 on page 79 of Mr. Hevert's evidence depict the historical raw beta estimates for his Canadian Utility sample over the 1995-2017 period

[87] For future reference, I note that adjusted betas (i.e., Bloomberg, Value Line, etc.) are determined using the following equation, which adjusts a raw (unadjusted) beta towards "1": Beta(adjusted) = (2/3)(Raw Beta) + (1/3)(1).

using five years of weekly data (Chart 20) and using five years of monthly data (Chart 21). I reproduce these two charts below.

Chart 20: Canadian Utility Proxy Group Unadjusted Beta Coefficients – Weekly Return over Five Years

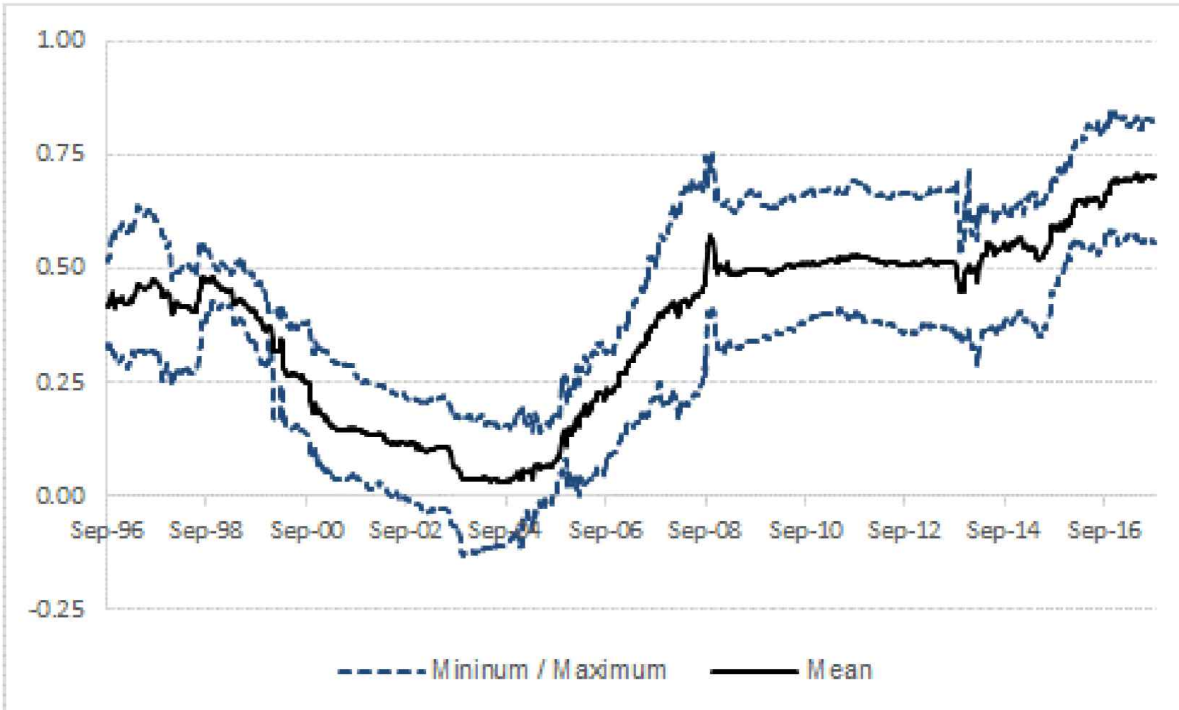
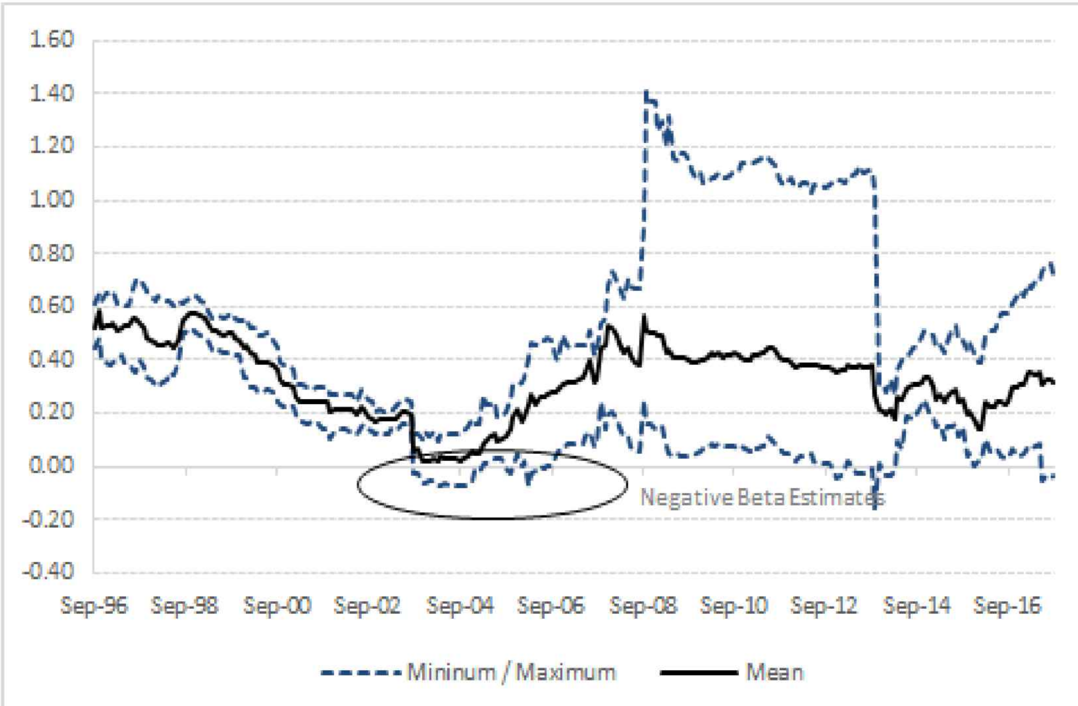


Chart 21: Canadian Utility Proxy Group Unadjusted Beta Coefficients – Monthly Return over Five Years



Mr. Hevert confirmed in response to HEVERT-UCA-2017NOV21-026(c) that the following statistics for Charts 20 and 21 are correct:

Chart 20 (weekly data): Average – 0.38 / Median – 0.43 / Max – 0.71

Chart 21 (monthly data): Average – 0.34 / Median – 0.37 / Max – 0.61

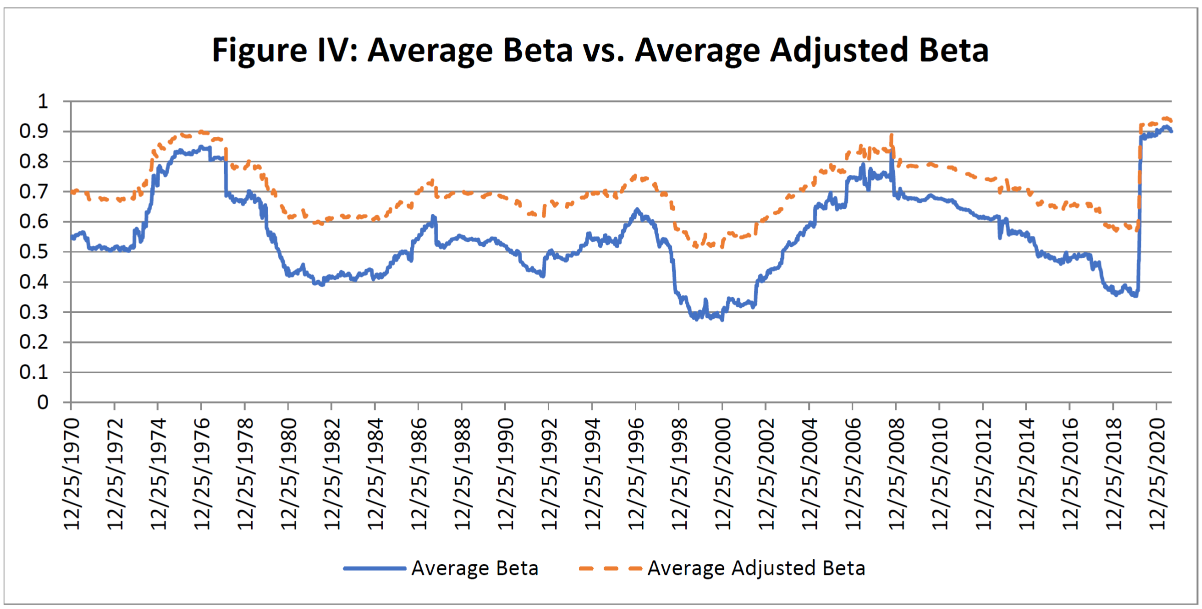
Notice that the reported averages here of 0.34 and 0.38 are consistent with those provided in Dr. Villadsen's 2016 rebuttal evidence between 0.31 and 0.35. Also, similar to the charts provided in Dr. Villadsen's 2016 rebuttal evidence, these two charts (i.e. Charts 20 and 21) clearly show that nowhere during this entire 22-year period do the Canadian Utility beta estimates even come close to 1.0, with maximum values of 0.71 and 0.61. This evidence confirms the fact that it makes no sense to adjust betas toward one.

Charts 22 and 23 on page 80 of Mr. Hevert's 2018 evidence also depicts the historical raw beta estimates for his U.S. Utility sample over the 1995-2017 period using five years of weekly data (Chart 22) and using five years of monthly data (Chart 23). Mr.

> Hevert confirmed in response to HEVERT-UCA-2017NOV21-026(e) that the following statistics for Charts 22 and 23 are correct:
>
> Chart 22 (weekly data): Average – 0.51 / Median – 0.52 / Max – 0.83
>
> Chart 23 (monthly data): Average – 0.43 / Median – 0.47 / Max – 0.82
>
> These two charts for U.S. utilities show that nowhere during this entire 22-year period do the U.S. Utility beta estimates even come close to 1.0.

The evidence above is consistent with the conclusions of Sikes (2022) regarding U.S. utility betas, who notes (pages 46-47) that in his study "Using adjusted betas instead of the appropriate unadjusted betas increased the CAPM estimate by ~100 basis points." He went on to note that this was consistent with the findings of Michelfelder and Theodossiou (2013) "who showed empirically that utility betas do not have a tendency to converge to 1.0 and concluded that the adjusted betas as reported by Value Line are not applicable for public utilities."

Sikes provided a chart (Figure IV) depicting raw versus adjusted betas for U.S utilities over a 50-year period, from 1970-2020, which I have copied below:



Source: Page 48 of Sikes (2020) – Attachment AT.

Sikes went on to note (page 48) that: "It is undeniable based on Figure IV that the Value Line Adjustment is inappropriate. Clearly, utility betas have been consistently below 1.0 and as shown in Attachment II of the Appendix, the historical sample suggests an average of 0.55." I would further note that the line depicting adjusted betas in Sikes' chart is **always** above the line depicting actual betas – this is the definition of a biased estimator – in this case **upwardly**

biased. Since the raw or unadjusted beta is used to predict the actual relationship between market returns and security returns (in this case utility returns), using adjusted betas will provide upwardly biased estimates of betas for future returns, as it always has done historically. Notice that the average of 0.55 noted by Sikes (2022) for U.S. utilities is higher than the Canadian average noted above, which is closer to 0.35. Charts 22 and 23 of Mr. Hevert's evidence also show that the 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 his 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).

To illustrate the impact that leverage differences would make, I note from Figure 28, page 76 of Dr. Villadsen's evidence in the 2018 Alberta GCOC proceeding that the 2017 allowed equity ratios for U.S. Natural Gas, Electric and Electric T&D are 48.7%, 48.6% and 48% respectively, versus 39.6% for all Canadian utilities. These suggest debt-equity (D/E) ratios of (51.5/48.5) for U.S. utilities and (60/40) for Canadian utilities. Using the Hamada equation used by Mr. Hevert in his 2018 evidence (page 103, equation [12]), and the 27% tax rate that he used in applying this equation, we can obtain the following equivalent "relevered" U.S. beta estimates that can be compared to the Canadian levered beta estimates of 0.38 and 0.34:

U.S. (monthly) beta estimate = 0.43:

1st: Unlever accounting for U.S. leverage ratios:

B(unlevered) = B(levered) / {[1 + (1 –Tax rate)](D/E)]}

= 0.43{[(1 + (1 - .27)](51.5/48.5)] = 0.43/{1.837} = 0.234

2nd: Relever accounting for Canadian leverage ratios:

B(levered) = B(unlevered) × {[1 + (1 –Tax rate)](D/E)]}

= 0.234{[(1 + (1 - .27)](60/40)] = 0.234 ×{2.595} = **0.61**

U.S. (weekly) beta estimate =0.51:

1st: Unlever accounting for U.S. leverage ratios:

B(unlevered) = 0.51 /{1.837} = 0.278

2nd: Relever accounting for Canadian leverage ratios:

B(levered) = 0.278 ×{2.595} = **0.72**

So, in fact the "comparable" U.S. beta historical averages of 0.61 (monthly) and 0.72 (weekly) are **much, much higher** than (i.e., **almost double**) the comparable Canadian beta estimates of 0.34 and 0.38, 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) using D/E ratios of 0.515/0.485 for U.S. utilities and using D/E ratios of 0.60/0.40 for Canadian utilities. This historical data provides strong evidence to suggest that in determining allowable ranges for regulated Canadian utilities, the Commission should **not** consider U.S. utility beta estimates.

The examination of the historical evidence above 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.**
3. **U.S. utility beta estimates are significantly higher than those for Canadian utilities, and should not be considered**.[88] 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 the Commission 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.[89] If there

[88] For example, I show above 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).

[89] This is consistent with the approach used by LEI in its evidence, with final beta estimates determined based on raw beta estimates.

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 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 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.

APPENDIX D

Discounted Cash Flow (DCF) Growth Estimates

During every proceeding that I have been involved in, utilities' experts have relied upon analyst growth estimates despite the well-known concerns about the overly optimistic nature of such forecasts, as noted in Mr. Coyne's Alberta GCOC 2018 rebuttal evidence on page 42 (lines 1-3), where he notes that "Research by Easton and Sommers[90] has put the "optimism" bias in analysts' growth forecasts at an average of 2.84 percent."[91] This upward bias in analyst growth estimates is not surprising because the publicly available analyst estimates are almost always (if not entirely) those provided by "sell-side" analyst estimates, which are generally overly optimistic, which is a well-known fact among finance professionals – i.e., by definition their job is to promote sales.[92] For example, it is well-known that sell-side analysts rarely issue "sell" recommendations on stocks and tend to provide overly bullish stock price forecasts: with 60-65% "buy" recommendations; 30-35% "hold" recommendations; and, usually less than 5% "sell" recommendations.[93]

Using analyst growth rates leads to adopting estimated future growth rates for utility earnings and dividends that exceed expected growth in the economy (i.e., nominal GDP growth), which is simply not realistic for mature, stable operating utilities operating within a defined region. In fact, in the Alberta GCOC Decision 22570-D01-2018, para. 438, the AUC recognized this fact, stating (footnote omitted) (emphases added)**:**

> 438. With respect to the single-stage DCF model estimates presented by Dr. Villadsen, Mr. Coyne and Mr. Hevert, the growth rates used by each of these three witnesses in their single-stage DCF models are in **excess of the long-term GDP growth estimates** they put forward. 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**

[90] 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.
[91] Source: Exhibit 22570-X0775, Rebuttal Evidence of James Coyne, page 42, PDF page 44, lines 1-3.
[92] The growth forecasts determined by "buy-side" analysts (i.e., analysts working for the financial institutions (like pension funds, mutual funds, etc.) that actually "provide the capital" and invest (rather than make commissions on the buy and sell transactions like the sell side), provide growth estimates are much lower and much more realistic.
[93] See for example: "Monitoring changes in analysts' advice gives key insight: report," (Tim Shufelt, Globe and Mail, Report on Business, May 24, 2019, page B7.

> **terminal growth rates that exceed estimates of the nominal long-term GDP growth rate for the economy**. 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.**"

Further, even the assumption of expected nominal GDP growth (i.e., average growth) estimated in my evidence at 3.3-4.3% is an ambitious target for regulated utilities that operate virtual monopolies in mature markets, with little opportunity for above average 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.[94]

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, 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.[95] 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.

In contrast, the growth rates that I estimate and use in my DCF models are determined using the company's **sustainable growth rate,** which is an approach included in the CFA curriculum and numerous academic textbooks, and is widely used in practice. This approach provides reasonable growth rates that are below the expected nominal GDP growth rate and make intuitive sense for the low-risk nature of regulated operating utilities operating in well-defined markets with limited growth potential.[96]

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[94] Decision 2191-D01-2015, 2013 Generic Cost of Capital, para. 190 [emphasis added] [footnote omitted].
[95] Individual company growth estimates were as high as 15.3%, which is clearly an even more unreasonable long-term growth expectation.
[96] In the past, the utilities' experts have pointed to some specific cases of higher growth displayed by utility "holding companies," which of course is a different issue, as they can grow "inorganically" by acquiring new

While LEI did not produce multi-stage DCF estimates, it is worth extending the current discussion to these models. An approach used by utilities' experts in previous Alberta proceedings to avoid rejection of their constant-growth DCF estimates that use growth rates above expected nominal GDP growth has been to incorporate these abnormally high growth estimates into the first growth stage (usually 10 years) of their multi-stage DCF estimates, and then assume a long-term growth rate equal to expected nominal GDP growth. However, as I demonstrate below, all of these multi-stage DCF estimates are based on growth assumptions that similarly violate the AUC's pragmatic growth condition noted above.

This is simply intuitive because if we consider using the higher analyst growth rates for a full 5 years (say 6.5%), then have these growth rates gradually decline over the following 5 years to a stable long-term growth rate equal to an estimate of long-term nominal GDP growth (say 3.9%), it is obvious that this is equivalent to using the single-stage growth model, with a long-term growth rate higher than expected nominal GDP growth of 3.9%.

For example, an information request during the 2023 Alberta GCOC proceedings, (i.e., CONCENTRIC-UCA-2023FEB21-017) asked Concentric to confirm the corresponding long-term constant-growth rate implied by its multi-stage DCF estimate of Ke (of 9.42% before flotation costs) was 4.45%, which exceeded Concentric's own estimate of future nominal GDP growth (of 3.84%), and which it used as its long-term growth rate in its multi-stage DCF Ke estimate.

In particular, CONCENTRIC-UCA-2023FEB21-017d asked:

(d) Worksheet JMC-4 provides the multi-stage DCF cost of equity estimate for the Canadian proxy group of 9.92%, or 9.42% before adding 0.5% for flotation costs. According to worksheet JMC-4, this estimate is based on a growth rate of 4.91% for years 1-5, 4.73% for year 6, 4.55% for year 7, 4.37% for year 8, 4.19% for year 9 and 4.02% for year 10, followed by long-term growth of 3.84% from years 11 to infinity. Please confirm that the long-term growth rate that would also lead to a 9.42% cost of equity estimate (pre-flotation costs) for the Canadian proxy group in the single-stage DCF model, based on its DY_1 of 4.97% would be 4.45%. I.e., since in the single-stage DCF model:

$$\text{Cost of Equity (9.42\%)} = DY_1 + g = 4.97\% + \mathbf{4.45\%}$$

If not confirmed, please provide the correct corresponding long-term growth rate in the single-stage DCF model that would result in a cost of equity estimate of 9.42% for the Canadian proxy group, based on its DY_1 of 4.97%.

operating companies. This is not an option for regulated operating utilities (like Ontario utilities), whose growth must come organically – i.e., through increased demand and revenues, or reduced operating costs.

In its response, Concentric did confirm the implied single-stage DDM growth rate of **4.45%** was determined correctly (but might be subject to a slight deviation due to a 0.5 adjustment to the dividend yield).

The discussion above shows mathematically (and intuitively) that using short-term growth rates in excess of expected nominal GDP growth, and then using expected nominal GDP growth as the long-term growth rate in multi-stage DCF models also produces Ke estimates that are based on unrealistic assumptions about future long-term growth for mature regulated utilities.