PREPARED REPORT:

ONTARIO GENERIC COST OF CAPITAL

PREPARED FOR:

ONTARIO ENERGY ASSOCIATION

COALITION OF LARGE DISTRIBUTORS AND ONTARIO POWER GENERATION

BEFORE THE:

ONTARIO ENERGY BOARD

JULY 19, 2024

CEADVISORS.COM

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF APPENDICES

LIST OF EXHIBITS

I. INTRODUCTION AND PURPOSE

A. Qualifications

This report was prepared by James M. Coyne, Daniel S. Dane and John P. Trogonoski of Concentric Energy Advisors, Inc. ("Concentric"). Our qualifications are set out below, and our CVs are attached as Appendix C.

We provide this report on behalf of Enbridge Gas Inc. ("Enbridge Gas"), the Coalition of Large Distributors ("CLD"), Ontario Power Generation ("OPG"), and Upper Canada Transmission 2, Inc. Enbridge Gas serves approximately 3.9 million customers in Ontario. The CLD consists of Alectra Utilities Corporation, Elexicon Energy Inc., Hydro One Networks Inc., Hydro Ottawa Limited, Toronto Hydro-Electric System Limited. Together, the CLD's members represent more than 3.6 million, or approximately 70% of, electricity consumers located across the province. OPG is Ontario's largest electricity generator, producing about half of the province's power. Upper Canada Transmission 2, Inc. is a transmitter that developed, constructed, and operates the East-West Tie Line. Collectively, we refer to this group as "utilities". Enbridge, the CLD, OPG, and Upper Canada Transmission 2, Inc. are represented in this proceeding by the Ontario Energy Association ("OEA").

1. James Coyne

James M. Coyne is a Senior Vice President with Concentric. Mr. Coyne has over forty years of experience in the utility and energy industries, with a specialization in regulatory policy and the cost of capital ("COC") for regulated utilities. This work includes estimating the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, fuels and power markets. Mr. Coyne has testified or provided expert evidence in over 50 proceedings in state, provincial and federal jurisdictions in Canada and the U.S., including before the OEB in the 2009 Generic Cost of Capital ("GCOC") proceeding and subsequent proceedings on behalf of Enbridge Gas and OPG on similar matters. Mr. Coyne has also worked with OEB Staff and provided expert reports on the cost of capital, low-income programs, and demand-side management programs. Mr. Coyne holds a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire.

2. Daniel Dane

Daniel S. Dane is the President of Concentric. Mr. Dane previously testified before the OEB on cost of capital matters in EB-2016-0152 and EB-2022-0200. Mr. Dane has more than 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, local gas distribution companies, and water utilities in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has provided expert testimony and developed expert reports on regulated ratemaking matters for investor- and provincially-owned utilities, including on the cost of capital and capital structure, earnings sharing mechanisms and rate adjustment mechanisms, revenue requirements, lead-lag studies/cash working capital, and utility productivity and benchmarking. Mr. Dane has also provided expert testimony in utility merger approval proceedings related to the financial and cost of capital implications of utility transactions. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. He is also a certified public accountant licensed in the Commonwealth of Massachusetts.

3. John Trogonoski

John P. Trogonoski is an Assistant Vice President with Concentric. Mr. Trogonoski has 25 years of experience in the utility and energy industries, specializing in matters pertaining to finance, economics, and public policy. Mr. Trogonoski has testified or provided expert evidence on more than 25 occasions in various U.S. state and Canadian provincial jurisdictions, on behalf of both utilities and regulatory commission staff. He assisted in the development of Concentric's report in the 2009 GCOC proceeding in Ontario. Prior to joining Concentric, Mr. Trogonoski was employed by the Colorado Public Utilities Commission where he supervised the financial analysts in the energy and telecommunications units, provided advisory services to the Commissioners on financial and economic matters, and filed expert testimony on rate of return and public policy matters among other issues. Mr. Trogonoski holds a M.S. in Business Administration and a B.S. in Marketing from the University of Colorado at Denver.

B. Purpose of Report

We have been asked to respond to the issues raised by the Ontario Energy Board ("OEB" or "Board") in the Approved Issues List ("Issues List") in EB-2024-0063, Generic Proceeding – Cost of Capital and

Other Matters. This includes an estimate of the cost of capital and recommended equity ratios for Ontario's electric distribution, electric transmission, gas distribution utilities and OPG (together represented by the OEA), among other issues. The analysis provided in this report supports our overall recommendations and responds to the OEB's specific questions pertaining to these matters. In addition, Concentric responds to the June 2024 report prepared by London Economics International LLC ("LEI"), an independent expert retained by OEB Staff to address the Issues List.

We acknowledge that we have a duty to provide opinion evidence to the Board that is fair, objective and non-partisan.

C. Report Organization

The remainder of this report is organized as follows:

Section II provides an executive summary of our recommendations regarding each of the issues raised by the Board in its Issues List. This includes authorized return on equity ("ROE") and deemed equity ratio recommendations, and the parameters to be used in the ROE formula for 2025 and beyond. We also address how often the Board should review the formula to ensure it is providing a fair return.

Section III summarizes the legal requirements and key regulatory precedents for setting a fair return.

Section IV addresses the Board's questions regarding certain general issues relevant to the determination of the cost of capital parameters in this proceeding (OEB Issues #1 through #3) and responds to the Board's questions pertaining to the methodology for calculating the short-term debt cost, long-term term debt, and transaction costs for debt issuances (OEB Issues #4 through #9).

Section V provides our estimation of the generic ROE for Ontario utilities. This section includes a discussion of the screening criteria we used to select companies that are comparable in risk to Ontario's utilities and how we have grouped those companies into proxy groups, as well as the methods used to estimate the cost of equity and summarizes the results of the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM") and Bond Yield Plus Risk Premium ("Risk Premium") analyses (OEB Issues #10 and #11).

Section VI discusses the performance of the ROE formula in Ontario and provides our recommendations regarding modifications to the ROE formula parameters (OEB Issues #10 and #11).

Section VII discusses capital structure and risk assessment considerations. In addition, we evaluate risks for Ontario's utilities and explain how those risks compare to the North American electric and gas proxy group companies. We also provide our recommended deemed equity ratios for Ontario's utilities (OEB Issues #12 and #13).

Section VIII provides recommendations regarding the mechanics of implementing cost of capital changes (OEB Issues #14 through #19).

Section IX addresses other issues raised by the OEB in its Issues List relating to prescribed interest rates for deferral and variance accounts ("DVA") and construction work in progress ("CWIP"), as well as the return on the Cloud Computing Deferral Account (OEB Issues #20 through #22).

Section X summarizes our conclusions and recommendations regarding the authorized ROE for Ontario's utilities, the deemed equity ratios, proposed modifications to the existing ROE formula to be used to adjust the authorized return in subsequent years, and Issues #1 through #22.

II. EXECUTIVE SUMMARY

A. Introduction

On March 28, 2024, the OEB initiated a generic proceeding in EB-2024-0063 to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and OPG. The OEB indicated that it will determine whether its current approach to setting the cost of capital parameters and deemed capital structures continues to remain appropriate, and if not, what approach should be used. In addition, as noted in the Notice of Hearing, this proceeding will also consider the methodology for determining the OEB's prescribed interest rates. Also in scope for this proceeding is the question of what type of interest rate, if any, should apply to the generic Cloud Computing Deferral Account. On June 21, 2024, LEI, engaged by OEB Staff, provided its expert report. In the report LEI reviews and provides recommendations for each issue identified on the Issues List[1] in this proceeding, which includes the following categories:

1) General Issues;
2) Short-term debt rate;
3) Long-term debt rate and transaction costs;
4) Return on Equity;
5) Capital Structure;
6) Mechanics of Implementation; and
7) Other Issues.

The Board is investigating these issues at an important time that reflects an inflection point experienced by segments of the regulated utility industry. At an accelerating pace over the last decade, the global energy sector has embarked on a broad-scale transformation, referred to generally as the "Energy Transition," from a primary reliance on fossil fuels to an increased emphasis on more non-emitting and decentralized fuel sources.[2] This Energy Transition, coupled with other factors such as the growth in data centers to serve the world's increasing computing needs, is causing

---

1 Ontario Energy Board, EB-2024-0063, Schedule A, Approved Issues List, April 22, 2024.
2 S&P Global, "What is Energy Transition," February 24, 2020, https://www.spglobal.com/en/researchinsights/market-insights/what-is-energy-transition

substantial changes for utilities, particularly in their capital investment plans. As noted by DBRS Morningstar in a recent report on the North American utilities sector:

> *The industry's ongoing allocation of substantial capital toward initiatives such as climate adaptation, modernization, and energy transition has reached unprecedented levels, with many utilities rolling out capital expenditure (capex) programs that are 10% to 20% greater compared with previous cycles… We anticipate the trend of elevated capex and reliance on debt financing will likely persist over the longer term.*[3]

Electric distributors and transmitters are building new infrastructure to meet electricity demand that some utility executives expect to triple by 2050.[4] OPG is engaging in long-term refurbishment projects for its nuclear plants with a high degree of execution risk, while also investing in first-of-a-kind new nuclear technologies. Enbridge Gas must continue to invest in its system to provide safe and reliable natural gas service while also navigating through increasing complexities for gas distributors brought on by the Energy Transition.

These "unprecedented levels" of required capital investment being deployed over long-tenured construction projects necessitate access to capital in an increasingly competitive and integrated investment market, emphasizing the importance of reassessing the OEB authorized cost of capital for Ontario utilities to ensure Ontario ROEs and equity ratios meet the Fair Return Standard (also referred to herein as the "FRS").

This importance is also accentuated by shifts in investors' perceptions of risk for the utility industry, as measured by betas, which, as discussed in our section on the CAPM, represent the risk of individual securities relative to the market. Utility betas have increased substantially for electric and gas utilities since January 2020, and since the OEB last considered this issue in 2009. This indicates that regulated utilities are seen as increasingly risky by investors. Utility betas have been in the range of 0.80 to 0.90 percent since early 2020, as compared to the historical average level of 0.60 to 0.70 in the preceding 10 years, notwithstanding the increase observed in 2009 in the wake of the Great Recession. This shift in utility risk is not reflected in the present Ontario formula, which highlights the importance of periodic reviews of the formula to ensure that it continues to produce a fair return.

---

3 DBRS Morningstar, "Losing Steam: Weakening Credit Metrics in the North American Utilities Sector," May 15, 2024.

4 S&P Global, "Utility execs prepare for 'tripling' of electricity demand by 2050," April 19, 2023.

Another gating factor in this review is the recognition that Ontario's economy and regulated utilities operate in a North American market, requiring a similar perspective on the cost of capital. This Board took important steps in 2009 in recognition of this trend. Concentric's recommendations fall short of parity between Ontario and U.S. utilities, but would advance the ability of Ontario's utilities to compete for investment capital on a comparable basis with their North American peers. Ultimately, a fair return facilitates the necessary investments in Ontario to meet the complex needs of its consumers, and progress toward environmental and economic priorities.

With these factors in mind, Concentric's analysis in response to the Issues List incorporates market data from multiple industry segments across North America and several analytical models. We have also reviewed LEI's analysis and findings, and, while we agree with certain elements of LEI's report, we also disagree in certain fundamental areas, and we discuss those areas herein.

B. Overview of Concentric Recommendations

In response to questions raised by the Board in its Issues List, Concentric recommends rebasing the authorized ROE for Ontario's utilities based on current market conditions, as well as certain modifications to the parameters of the existing ROE formula. We also recommend changes to the deemed equity ratios for Ontario's utilities based on an analysis of business risk and a comparison to the equity ratios of comparable North American utilities. Concentric also addresses how often the OEB should review whether the formula is producing a return that satisfies the Fair Return Standard, what factors might cause the Board to review or suspend the formula, and the mechanics of updating the ROE formula. Our report also reviews and provides recommendations regarding the cost of short-term and long-term debt, as well as prescribed interest rates for DVAs, the appropriate cost of capital for CWIP accruals, and appropriate carrying charges for the Cloud Computing Deferral Account.

C. The Base ROE

This is the Board's first full proceeding to review the formula since it issued its Report of the Board on the Cost of Capital for Ontario Regulated Utilities (EB-2009-0084) ("2009 Report") on December 11, 2009. In that decision, the OEB set the base ROE at 9.75 percent for Ontario's electric and gas utilities and made certain modifications to the formula in response to concerns that the formula was not producing a return that satisfied the Fair Return Standard.

The allowed ROE for Ontario utilities must meet the Fair Return Standard, regardless of how it is set. Concentric's view is that the most reliable way to estimate an ROE that meets the Fair Return Standard is a full analysis using updated market data in conventional cost of capital models. Once rebased, it remains possible to continue using an ROE formula to reflect changes in capital markets between rebasing intervals.

D. Approach to Estimating Base ROE

An assessment of the appropriate return for Ontario's utilities relies on the fundamental legal and regulatory principle that a utility must have a reasonable opportunity to earn a fair return on its invested capital. The following three standards determine whether a return is fair:

- the comparable investment standard;
- the financial integrity standard; and
- the capital attraction standard.[5]

These standards must be met individually and collectively to satisfy the Fair Return Standard, and none ranks as more important than another.

Our analysis utilizes a traditional evidentiary approach based on current market data and well-established models. In this way, the Board can be assured that the ROE established in this proceeding meets the Fair Return Standard.

Concentric's ROE analysis includes six proxy groups: a Canadian group, a U.S. Electric group, a North American Electric group, a U.S. Gas group, a North American Gas group, and a North American Combined group. The subgroups are intended to evaluate whether there are meaningful differences between electric and gas utilities with respect to business and financial risks and their estimated ROEs. We have estimated the ROE using three commonly employed models: the DCF model, both constant growth and multi-stage forms; the CAPM; and the Risk Premium approach, with alternative inputs and model specifications designed to test the reasonable range of results.

The results of the alternative models are summarized in Figure 1. Because the utilities in the North American proxy groups are most representative of Ontario's utilities, we place more weight on those

[5] The OEB has accepted these standards. See, for example, the 2009 Report, p. 18.

results. While Concentric estimated the return on equity under various analytical approaches, we have narrowed the results to three models (i.e., the Multi-Stage DCF, the historical CAPM, and the Risk Premium approach) to develop our ROE rebasing recommendation in this proceeding. Those models provide a conservative (lower) estimate for Ontario utility ROEs relative to other models and are consistent with models that have been relied on in other jurisdictions evaluating a generic cost of capital to be applied across industry segments. Those models' results range from 9.7 percent to 10.3 percent, depending on the proxy group. It is important to emphasize that these results are based on conservative model inputs and, therefore, represent the lowest reasonable estimate of the required return for Ontario's electric and gas utilities as a whole.

Figure 1: Summary of ROE Results[6]

	CANADIAN PROXY GROUP	U.S. ELECTRIC PROXY GROUP	U.S. GAS PROXY GROUP	NORTH AMERICAN ELECTRIC PROXY GROUP	NORTH AMERICAN GAS PROXY GROUP	NORTH AMERICAN COMBINED
MULTI-STAGE DCF	10.38%	9.87%	9.60%	9.83%	10.21%	9.95%
CAPM – HISTORICAL MRP	9.36%	10.62%	10.00%	10.23%	9.89%	10.22%
RISK PREMIUM	9.44%	10.36%	10.30%	9.90%	9.87%	10.03%
AVERAGE	**9.7%**	**10.3%**	**10.0%**	**10.0%**	**10.0%**	**10.1%**

We also present a risk assessment of Ontario's utilities in relation to the proxy group companies for purposes of determining the appropriate deemed equity ratios for Ontario's utilities. Lastly, we assess whether our recommendations meet all three prongs of the Fair Return Standard.

Based on these results, we conclude that the current formula return of 9.21 percent in Ontario has diverged from a fair return for comparable risk companies, and changes to the authorized ROE and the deemed equity ratios for Ontario's utilities are required to meet the Fair Return Standard.

6 The DCF and CAPM results include an adjustment of 50 basis points for flotation costs and financial flexibility.

E. Cost of Capital Recommendations

Our recommendations are based on a cost of capital analysis utilizing the aforementioned models and a combination of Canadian, U.S., and North American proxy groups. We have also considered Ontario's regulatory precedents and the foundational regulatory principles that guide the OEB on these matters. This broader analysis is then applied to Enbridge Gas, the CLD, OPG, and Upper Canada Transmission 2, Inc. with specific consideration of the business and financial risks of Ontario's utilities in relation to the proxy companies. Based on the foregoing, we recommend the following:

1. An authorized base ROE of **10.0** percent, up from the base ROE of 9.75 percent in the current OEB formula and up from the current ROE of 9.21 percent resulting from the formula. This ROE recommendation is based on the average results of the multi-stage DCF model, the CAPM using a historical market risk premium for the North American combined proxy group, and the Risk Premium model, which is the most conservative (lower) estimate of the required return. We further recommend that LEI's proposed 8.95 percent base ROE not be accepted by the Board. An 8.95 percent authorized ROE would be in the bottom decile of authorized ROEs among Canadian and U.S. utilities and would not satisfy the Fair Return Standard.

2. As discussed herein, OPG faces a different and heightened level of risk compared to distributors and transmitters. In addition, the OEB has previously found that there is a heightened risk of nuclear generation relative to hydroelectric generation,[7] which is important to consider as OPG embarks on first-of-a-kind nuclear projects in addition to refurbishing its existing nuclear units. As such, the base ROE recommendation of 10.0 percent understates the ROE needed to meet the Fair Return Standard for OPG. There are also no direct comparators in the proxy groups analyzed by Concentric for OPG's pure-play rate-regulated generation operations. Rather than set alternative generic ROEs in the proceeding, however, Concentric recommends that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied to its authorized ROE, the OEB consider that proposal at its discretion as part of that proceeding.[8]

---

7 See, e.g., EB-2016-0152, Decision and Order, December 28, 2017, p. 102.
8 Consistent with the OEB's finding in EB-2009-0084 Report of the Board, p. 13.

3. With regard to equity thickness, Concentric's primary finding within the context of this generic cost of capital proceeding is that Ontario equity ratios across all industry segments are lower than North American industry peers and fail to meet the comparable return standard component of the Fair Return Standard. While we continue to support the use of equity thickness to distinguish risk profiles among Ontario utilities, we have not recommended individual changes to each utility's equity thickness. Rather, we recommend that the deemed equity ratio be set at a minimum of 45.0 percent for *all* Ontario utilities, but that each utility have the option to retain its current equity ratio and/or propose differences from the "generic" equity thickness in its rates application. Concentric's recommendation of a minimum equity thickness of 45.0 percent reflects approximately the midpoint between the current deemed equity ratios in Ontario, which are generally consistent with the Canadian average deemed equity ratio for investor-owned utilities (see Figure 27), and the authorized equity ratios for U.S. electric and gas utilities. With respect to OPG, Concentric finds that its business risk is higher than the presented proxy group due to OPG's generation-only operations and recommends that the OEB accordingly determine an appropriate increase to the equity ratio in the company's next payment amounts proceeding.
4. Alternatively, if the OEB maintains the current deemed equity ratios of 38.0 percent for Enbridge Gas and 40.0 percent for Ontario's electric transmission and distribution utilities, then we recommend adjusting the authorized generic ROE for differences in financial leverage between the Ontario utilities and the proxy group companies. This would result in an upward adjustment of 138 to 163 basis points to our 10.0 percent ROE recommendation, based on the North American Electric, North American Gas and North American Combined proxy groups and the CAPM analysis using a historical market risk premium.
5. These recommendations meet the requirements of the Fair Return Standard and stand-alone principles the Board has embraced in the past and should provide sufficient financial support for the services provided by Ontario's utilities for the benefit of the province's energy consumers.

The current Ontario formula return of 9.21 percent is lower than the average, and lower than any of the results from the financial models and is not representative of the capital market environment and required returns for Ontario's utilities. Further, while the current deemed equity ratios for electric utilities in Ontario are near the Canadian average, and the deemed equity ratio for gas distribution is below the Canadian average, both electric and gas equity ratios in Ontario are well below their U.S. peers. Under the comparable return standard, both the authorized ROE and the deemed equity ratio for regulated utilities must be comparable to the returns available to investors in entities with similar risk. Equity investors and credit rating agencies consider authorized returns and deemed equity ratios as relevant benchmarks against which to measure whether the return in Ontario is comparable, on a risk-adjusted basis, to the returns in other jurisdictions across North America. On this basis, there is a gap that places Ontario's utilities at a comparative disadvantage when it comes to attracting capital. This gap has existed for many years but is now exposed by the increased integration of North American (and global) capital markets and utilities industries combined with increased demand for capital through the Energy Transition and will eventually harm Ontario's consumers as investment capital migrates to other uses or jurisdictions providing superior returns.

F. ROE Formula Recommendations

As discussed above, the most reliable method for determining required investor returns is a full presentation of refreshed market data and models used to estimate required returns (i.e., DCF, CAPM, Risk Premium). In addition, Concentric recommends minor modifications to the existing Ontario formula itself. From our examination, the Ontario ROE formula has generally resulted in ROEs that are in line with authorized returns for other Canadian electric and gas utilities but lower than the average authorized returns for comparable risk U.S. peers, and tend to further deviate from those required by the Fair Return Standard during periods of extreme stress in financial markets such as 2008-2009 and 2020-2021. Any formula-based approach must incorporate safeguards to ensure the formula-based ROE meets the Fair Return Standard, which requires suspending or rebasing the formula when it does not. In this case, it is critically important that the OEB take this opportunity to reset the base ROE to reflect current market data, thereby improving the probability that subsequent returns under a formula will remain within a reasonable range.

G. Implementation Issues

Periodic rate hearings remain the only reliable method for determination of utility ROEs that remain consistent with the Fair Return Standard. Understanding this limitation, Concentric recommends the Board take several steps to limit the potential impacts of deviations between the formula ROE, deemed capital structures and a fair return. Concentric recommends the OEB track and compare the following key utility and broader macroeconomic parameters on an annual basis:

- Authorized ROEs and equity ratios in other Canadian jurisdictions (individually) and the U.S. by industry segment (electric, gas) as reported by Regulatory Research Associates ("RRA")
- 10 and 30-year Treasury Bond Yields (Canada and the U.S.)
- A- and BBB-Rated Utility Bond Yields (Canada and the U.S.)
- Betas for the North American Proxy Group as defined in Section V
- Credit ratings from each agency covering Ontario's rate-regulated utilities.

Concentric recommends credit rating monitoring in order to provide some protection from insufficient earnings and credit quality, and a continuation of the 300 basis point trigger mechanism policy for all rate-regulated utilities, in conjunction with earnings-sharing mechanisms, to provide protection from excessive earnings.

Consistent with Concentric's recommended changes to the formula inputs, we recommend a continuation of annual updates to the OEB's cost of capital parameters in October, using data as of September 30th, except where forecasts are utilized. Concentric generally recommends trailing 90-day averages where historic data are utilized to avoid the inherent volatility in a single month's data.

Concentric recommends periodic cost of capital reviews with refreshed market data on ROE and capital structure every five years. Taken together, these steps provide a reasonable balance between the regulatory efficiency of a formulaic based approach and the requirements of meeting the Fair Return Standard.

Concentric believes it would be appropriate for changes in the cost of capital parameters and/or capital structure arising from this proceeding to be implemented in the next rate year, including for utilities in an approved rate term, subject to any settlement agreements and each utility submitting a compliance filing demonstrating how the change will be implemented within the context of its specific IR plan (e.g., Custom IR or I-X plan). All other elements and incentives of existing rate plans would remain in effect.

H. Other Issues

Concentric's report also provides findings and recommendations on the other issues included in the Issues List, including on the costs of debt and carrying costs on DVAs, CWIP, and the Cloud Computing Deferral Account. Specifically, Concentric's view is that the approach to determining the appropriate carrying costs to apply to DVAs and CWIP be based on regulatory and corporate finance principles. The application of the weighted average cost of capital ("WACC") to both DVAs and CWIP is most consistent with those principles, and, as such, Concentric recommends the WACC be used to calculate carrying costs on DVAs and CWIP. However, understanding the Board's historical preference to apply a short-term interest rate to DVAs, Concentric recommends that for DVAs that are to be cleared within one year, the short-term prescribed interest rate continue to apply.

As noted previously, Concentric also responds herein to LEI's report.

III. LEGAL REQUIREMENTS AND REGULATORY PRECEDENTS

The principles surrounding the concept of a "fair return" for a regulated company were established by the Supreme Court of Canada in the *Northwestern Utilities v. City of Edmonton* (1929) ("Northwestern") case, where the Supreme Court found:

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[9]

More recently, the Supreme Court of Canada in *Ontario (Energy Board) v. Ontario Power Generation Inc.* confirmed *Northwestern*, stating:

> *This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers.*[10]

The law regarding fair return for utility cost of capital in the United States has evolved similarly. The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*[11], the Court recognized that a rate of return may become unreasonable due to changing market conditions:

> *The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be*

9 Northwestern, p. 193.
10 Ontario (Energy Board) v. Ontario Power Generation Inc. 2015 SCC 44 at para 16.
11 (262 U.S. 679, 693 (1923)).

> *reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.*[12]

The U.S. Supreme Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company*[13]. The Court emphasized the role of risk in this analysis and described the relevant criteria as follows:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*[14]

With the passage of time, the Fair Return Standard has been interpreted many times in both Canada and the U.S. For example, the National Energy Board ("NEB", now the "CER") summarized its interpretation of the "Fair Return Standard" in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.* RH-1-2008 Decision.

> *The Board is of the view that the Fair Return Standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should: be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard); enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*
>
> *In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.*[15]

---

12 Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

13 (320 U.S. 591, 603 (1944)).

14 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

15 National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, p. 17.

All three standards must be met, and none ranks in priority to the others. To that point, the OEB articulated the legal requirements for satisfying the Fair Return Standard in Canada in its 2009 Report as follows:

> *The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.*[16]

***

> *… all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to the comparability test is not sufficient to meet the [Fair Return Standard].*[17]

Importantly, the Fair Return Standard applies both to the authorized ROE and the deemed capital structure.

A. The Stand-Alone Principle

The stand-alone principle provides that a utility should be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital is efficiently allocated, with each business segment earning a return based on its own unique risks and business characteristics regardless of affiliations within the holding company structure. The OEB has endorsed the stand-alone principle in its findings regarding the deemed capital structure for OPG. For example, the OEB concluded that it would apply the stand-alone principle in establishing the capital structure for OPG, noting that "[t]he stand-alone principle is a long-established regulatory

16 Ontario Energy Board, EB-2009-084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. i.
17 Ibid, p. 19.

principle,"[18] and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[19]

The BCUC reiterated its adherence to this principle in its most recent generic cost of capital decision:

> *In the BCUC's application of the Fair Return Standard, the utility must also be assessed based on the standalone principle. That principle provides that the utility should be regulated as if it were a standalone entity, raising capital on the merits of its own business and financial characteristics, regardless of affiliations within the holding company structure. The BCUC had noted the relevance of the standalone principle in past cost of capital decisions, and we continue to adhere to this principle to determine FEI and FBC's cost of capital in this proceeding.*[20]

In Concentric's view, it is consistent with both financial theory and regulatory practice to determine the cost of capital based on the *use* of funds and not the *source* of funds when determining just and reasonable rates. This principle is consistent with the application of the stand-alone principle. We discuss this point in more detail in response to **Issue #1** in Section IV of our Report.

B. Relationship Between Capital Structure and ROE

The equity ratio and equity rate of return must be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate for the additional financial risks faced by their shareholders. Consequently, when a regulator approves a deemed capital structure, that decision impacts the required rate of return on equity. As fixed debt obligations increase, the equity buffer (unencumbered earnings available to shareholders) narrows, and the required equity return increases to compensate investors for the additional risk to earnings. The fair return, therefore, depends on both the equity return and capital structure. The exact tradeoffs between the ROE and equity ratio are difficult to quantify with precision, but widely used leverage models such as the Hamada equation (which is an extension of the Modigliani-Miller theorem on capital structure) are based on the fundamental premise that there is a link between the cost of equity and the capital structure – as the capital structure becomes more leveraged, the cost of equity increases.

18 EB-2007-0905, Decision with Reasons, November 3, 2008, p. 140.
19 Ibid, p. 142.
20 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1) Decision and Order G-236-23, September 5, 2023, p. i-ii.

North American regulatory practice generally follows two alternative approaches to setting the capital structure and ROE: 1) the generic approach, and 2) setting ROE and capital structure based on individual proceedings. In Canada, the generic approach is common practice, but this approach is applied differently across provinces. Some jurisdictions use a single authorized ROE applicable to the generic or benchmark utility and reflect differentiation in utility risk through a deemed equity ratio (e.g., historically Ontario[21] and Alberta[22]). Other jurisdictions provide a generic ROE and differentiate the utility risk profile through an adjustment to the utility's ROE, or its deemed capital structure, or both (e.g., British Columbia[23] and Quebec[24]). In the U.S., the utility's actual book capital structure is often an important factor for ratemaking purposes, and regulators most often determine the reasonableness of each utility's capital structure based on that utility's risk profile relative to its proxy group, peer equity ratios, credit metrics, and specific circumstances. Capital structure is most often assessed each time the ROE is established, typically in individual utility rate proceedings.

21 Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084 (December 11, 2009), p. 50. Note that historically Ontario had provided ROE differentiation between its gas distributors but currently all distribution utilities are subject to the formulaic ROE. Timing, however, may vary between utility rate plans, causing ROEs to differ among utilities.

22 Alberta Utilities Commission, 2013 Generic Cost of Capital Decision, Decision 2191-D01-2015 (March 23, 2015) para. 416, p. 84.

23 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 2) Decision (March 25, 2014).

24 The Régie has awarded different capital structures and returns on equity for Gazifére (9.05% on 40% equity, D-2022-119, R-4156-2021 Phase 2, October 26, 2022), Gaz Métro (8.9% on 38.5% equity, Decision D-2022-119, R-4156-2021, Phase 2, October 26, 2022), and Hydro Québec Distribution (8.2% on 35% and Hydro Quebec TransÉnergie at 8.2% on 30%, D-2014-037, R-3854-2013, Phase 1, March 6, 2014).

IV. GENERAL ISSUES

The OEB has asked parties to address three general issues in their submissions, as outlined below:

> **Issue #1**: Should the approach to setting cost of capital parameters and capital structure differ depending on the source of capital (i.e., whether a utility finances its business through the capital markets or through government lending such as Infrastructure Ontario, municipal debt, etc.) or on different types of ownership (e.g., municipal, private, public, co-operative, not for profit, Indigenous / utility partnership?
>
> **Issue #2**: What risk factors (including, but not limited to, the energy transition) should be considered, and how should these risk factors under the current and forecasted economic and market conditions be considered in determining the cost of capital parameters and capital structure?
>
> **Issue #3**: What regulatory and rate-setting mechanisms have impacted risk factors, and how should they be considered in determining the cost of capital parameters and capital structure?

In response to **Issue #1**, Concentric does not recommend that the approach to determining the authorized ROE or capital structure be differentiated by ownership type. According to financial theory, the cost of capital depends on the *use* of funds, not the *source* of funds. It also depends on the available returns from alternative investments of comparable risk, known as opportunity cost. Assuming that investors in Ontario's utility businesses have comparable investment alternatives, the determinative factor is the *use* of funds. Practically speaking, if the Board were to determine the source of funds was determinative, the Board would be required to distinguish between the cost of equity from different investors, and the sources of potential investment are numerous. Rather, the most appropriate way to measure the cost of capital is to analyze current market data for a proxy group of companies with comparable business and financial risk as Ontario's regulated utilities. As Dr. Roger Morin explains in his book, New Regulatory Finance, "[e]quity is equity, irrespective of its source, and the cost of equity is governed by its use, by the risk to which it is exposed."[25]

25 Morin, Roger A., New Regulatory Finance, Public Utilities Reports, Inc., 2006, p. 523.

The OEB embraced a similar perspective in its 2009 Report, citing to Dr. Bill Cannon:

> *And, fourth, it [the cost of capital] reflects the risk of the investment. It reflects the expected returns on investments in the marketplace that are exposed to equivalent risks. Another way of expressing this principle is to say that the cost of capital depends on the use of the capital – or, more precisely, the risk associated with the use of the funds – and not on the source of the funds.*[26]

Continuing in its 2009 Report, the Board found:

> *In Ontario, utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no compelling reason to adopt different methods of determining the cost of capital based on ownership.*[27]

Concentric agrees with the Board's conclusion in 2009 and sees no financial or regulatory basis for modifying this approach based on ownership.

LEI's Recommendation and Concentric's Response

LEI reached a similar conclusion, recommending that:

> *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).* (LEI Report, p. 53)

Concentric agrees with LEI's recommendation.

[26] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 25.

[27] Ibid., p. 25-26.

In response to **Issue #2**, there are several risk factors that should be considered in determining the appropriate cost of capital for Ontario's regulated utilities. In general, utility-specific risk factors are considered in the assessment of the cost of capital to determine where, within a reasonable range of results, a subject utility's ROE and capital structure should be set. Since the OEB's historical approach has been to set a uniform ROE that applies to all jurisdictional utilities, utility-specific risk factors have been used to determine deemed equity thicknesses. Concentric recommends that utility-specific factors continue to be used in determining whether a utility's equity thickness, in combination with the generic ROE, meets the Fair Return Standard.

There are two fundamental sources of risk for any company, including regulated utilities: business risk and financial risk. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs, including a fair return on and of its capital in a timely manner. These risks must be evaluated on a prospective basis. Key among these risks are energy transition-related risk and regulatory risk, but they also include risks related to climate change and severe weather, competition between alternative fuels, political risk, risks related to capital spending, volumetric risk, and timely recovery of expenses, among others. Financial risk is related to a company's debt leverage and liquidity and is measured by its credit profile. Both business and financial risk have a direct bearing on a utility's cost of capital, further defined by the utility's regulatory risk. Below, Concentric provides a high-level description of these risk factors, and our assessment of each industry segment's risk profile is provided in more detail in Section VII.

A. Business Risk

1. Energy Transition

North American utilities are facing increased business risk due to changing customer preferences, environmental policies and laws such as the Clean Electricity Regulations (proposed) under the Canadian Environmental Protection Act and the Canadian Net-Zero Emissions Accountability Act (2021) and analogous provincial and municipal regulations and polices (e.g. Ontario's Emissions Performance Standards). At an accelerating pace over the last decade, the global energy sector has embarked on a broad-scale transformation, referred to generally as the "Energy Transition," from a primary reliance on fossil fuels to an increased emphasis on more renewable and decentralized fuel sources.[28] Rising demand for electricity as well as energy security considerations have also led to a need to diversify clean energy generation, such as nuclear energy, to provide reliable, low-cost generation capacity over the long-term. New electricity transmission infrastructure will be necessary, and the most cost-effective way, to support the growing electricity demand.[29] As a result, the risk profile of utilities in North America has fundamentally changed.

The Energy Transition affects nearly every aspect of existing utilities' businesses, from their growth prospects, to the capital projects pursued, to their fundamental ability to secure and offer investors the opportunity to earn a fair return on capital. In Ontario alone, gross capital spending across electric distributors increased from $1.8 billion annually in 2012 to over $2.5 billion annually in 2022,[30] highlighting the sector's increasing need for both capital spend and recovery. This increase is reasonably expected to continue in the short to long term as a consequence of the Energy Transition. With respect to electricity generation, in addition to completing the Darlington refurbishment, OPG has begun advancing, in parallel, two large-scale nuclear projects – the development of four small modular reactors ("SMRs") at the Darlington site and the planned refurbishment of four reactors at the Pickering Nuclear Generating Station.

At the same time, Enbridge Gas must continue to invest in its system to provide safe and reliable natural gas service while also navigating through increasing complexities for gas distributors brought on by the Energy Transition.

Consequently, the Energy Transition has already increased both business and policy-related risks for all Ontario utilities and is inevitably going to continue to do so.

2. Regulatory Risk

Utilities operating in any jurisdiction face significant regulatory risk that should be considered in the evaluation of a reasonable range of returns. In their analysis and ratings, credit rating agencies assess whether the utility's regulatory environment is constructive and supports the predictability of cash flow. For example, Moody's Investors Service ("Moody's") weighs the "stability and predictability of regulatory regime" at fifteen percent in its regulated electric and gas network methodology.

---

28 S&P Global, "What is Energy Transition," February 24, 2020, https://www.spglobal.com/en/researchinsights/market-insights/what-is-energy-transition
29 Government of Ontario, "Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future," 2023.
30 Data cited from OEB's Yearbook of Electricity Distributors and Open Data, Section 2.1.5.2 Capital

Regulatory decisions detrimental to credit quality, such as the utility's inability to attract sufficient capital or recover capital costs, increase the downward pressure on credit ratings. Lower credit ratings signal higher risk to investors, which then increase capital costs for utilities putting additional financial pressure on the company and its customers.

Ratings agencies similarly consider the supportiveness of the regulatory framework, or "the extent to which the regulatory formula is supportive of cost recovery, including the mechanism by which one-off costs or over-spends are recovered, if at all."[31] The utility's ability to fairly recover increased investment spending and costs related to severe weather or other external factors will be considered in the overall credit rating and consequently impact the cost of capital.

Regulatory risks encompass the additional risks of regulatory lag and timely recovery, which should be factored into the overall risk profile of the utility. Below is a discussion of regulatory lag and recovery risks faced more broadly by the utility industry, with Ontario-specific examples provided as well.

<u>Operating expense recovery</u>: Predictability and transparency of the regulatory framework to enable recovery of prudently-incurred operating expenses help support the risk profile of operating companies, and support risk mitigation for investors. The ability to recover operating expenses "underpins utility's predictable and steady cash flow" via timely recovery of prudently spent capital and operating expenses.[32]

<u>Volumetric risk</u>: Full and partial decoupling mechanisms and other rate design approaches in North America will continue to be an important consideration in utilities' ability to recover fixed costs, especially as volumes of natural gas sold decline for natural gas distributors, and variability increases for electric utilities. The same is true for an electricity generator such as OPG, with cost recovery variability related to generation output. Absent regulatory mechanisms to mitigate against volumetric risk, higher regulatory risk will warrant a higher level of return and cost of capital for utilities.

31 Moody's Investors Service, "Rating Methodology Regulated Electric and Gas Networks," April 13, 2022, p. 10.
32 S&P Global, "Enbridge Gas Inc.," February 1, 2022, p. 5.

Deferral and variance account mechanisms: Credit-supportive regulatory mechanisms, such as the DVAs established by the OEB, enable recovery of prudently incurred pass-through costs and reduce the risk of cost recovery for utilities. The predictable availability of DVAs and other risk mitigating mechanisms helps to ensure that utilities can maintain operations and the ability to recover costs in a timely manner, especially during challenging market conditions, in response to severe weather events, and when other unforeseen circumstances arise. Importantly, however, often the circumstances that give rise to the use of deferral and variance adjustment mechanisms (e.g., energy and regulatory policy changes) create additional risks for utilities. In that regard, DVAs can help to neutralize those new sources of risk, but they do not necessarily eliminate or offset those risks. In addition, Ontario is not unique in its application of deferral and variance mechanisms, as such mechanisms are widely employed throughout the North American utility industry, as discussed in our comparative risk discussion.

For Ontario's electric distributors, the OEB has authorized the use of DVAs to mitigate pass-through cost (e.g. commodity cost) variances. These accounts, known as "Group 1" accounts, do not require a prudence review.[33]

The OEB has also made available DVAs for electric distributors to record unforeseen or unpredictable costs, known as "Group 2" Accounts. According to the OEB's Accounting Procedures Handbook for Electricity Distributors, Group 2 accounts require a prudence review.[34] These DVAs may be introduced as a result of policy changes (e.g., the Customer Choice Initiative to facilitate time-of-use pricing[35]), or custom DVAs can be proposed by individual utilities to manage unpredictable costs (e.g., related to customer-driven work, such as road relocations or distributed energy resource ("DER")-enabling investments) within a cost of service application.

In some instances, DVAs introduced by the OEB may require formal requests and approval before costs can be recorded. For example, the OEB has made some Group 2 DVAs available sector-wide without application (e.g., the Low-income Energy Assistance Emergency Financial Assistance

33 See, e.g., Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EB-2008-0046), July 31, 2009.
34 Accounting Procedures Handbook For Electricity Distributors, effective January 1, 2012, p. 13.
35 Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Customer Choice Initiative Ontario Energy Board (EB-2020-0152), September 16, 2020.

Funding Deferral Account[36]); other DVAs may be conceptually endorsed by the OEB, but are subject to approval on a case-by-case basis.[37] Amounts recorded in a Group 2 account are subject to a prudence review at disposition, which can draw increased regulatory scrutiny.

OPG has several DVAs related to its hydroelectric and nuclear assets, the majority of which would be equivalent to "Group 2" accounts according to the OEB's Accounting Procedures Handbook, requiring a prudence review before the recorded costs are allowed for recovery. The review and disposition takes place on a periodic basis based on actual accumulated balances.

Enbridge Gas does not categorize DVA's as either Group 1 or 2. Enbridge Gas's DVAs are broadly divided between commodity-related deferral accounts and non-commodity-related deferral accounts. Commodity-related DVAs are mechanistic in nature and are used to pass through gas costs to ratepayers and are cleared prospectively on a quarterly basis through quarterly rate adjustment mechanism proceedings. Non-commodity accounts, which are generally comparable to Group 2 accounts for electric local distribution companies ("LDCs"), are subject to a prudence review and are predominantly disposed of on an annual basis. Each DVA is established on its own merits with the purpose of keeping ratepayers and the utility whole.

<u>Fuel and purchased power costs</u>: Timely recovery of prudently managed fuel and purchased power costs provides cash flow and financial stability and predictability for utilities. The direct pass-through of commodity costs mechanism are common in North America, allowing utilities to fully recover any fuel and purchased power costs from their customers without any lag.

<u>Capital spending and cost recovery</u>: The utility's ability to recover prudently-incurred capital costs in a comprehensive and stable manner both for ongoing capital programs and major projects, and to accrue (and ultimately recover) appropriate financing costs during construction, is necessary to raise funds for future capital spending needs. The importance of timely capital cost recovery and the recognition of construction financing costs is amplified during periods of increased industry-wide construction activity and due to cost pressure from the tightening of the labour and supply markets.

---

36 Changes to the Low-income Energy Assistance Program Emergency Financial Assistance and Accounting Orders (EB-2023-0135), February 12, 2024.

37 See, e.g., the "Framework for Energy Innovation: Setting a Path Forward for DER Integration," January 2023, p. 27-28.

Industry-wide construction activity is necessary to facilitate the Energy Transition. Section IX provides Concentric's comments on the recognition of financing costs during construction.

3. Other Business Risks

Other business risks that should be considered when evaluating the appropriate cost of capital include severe weather events (more frequent and severe weather events, such as wildfires, hurricanes, and floods that pose the highest physical risk to utilities than any other sector),[38] competition from alternative fuels (displacement of fossil fuels with cleaner alternatives) and system bypass, technology risk and two-way power flows, increased expectations regarding reliability, and changes in government policies, .

B. Financial risk

Financial risk, which focuses on solvency and liquidity, is often measured through credit metrics, and a utility's credit rating provides a widely-accepted opinion from a third-party credit rating agency of the utility's overall creditworthiness.

Regulatory framework decisions that restrict the utilities' ability to recover costs and increase the volatility of cash flows impact credit metrics used by rating agencies to further assess the financial health of the company. Moody's and S&P Global use a set of key credit ratios to assess rating actions. Funds from Operations ("FFO")/Debt and Cash From Operations Pre-Working Capital ("CFO")/Debt are evaluated by S&P Global and Moody's, respectively, for all regulated utilities, as well as debt/Earnings Before Interest, Depreciation, and Amortization ("EBITDA") for midstream utilities such as Enbridge, Inc.

Credit ratings directly impact the cost of debt and are considered by equity investors in their assessment of the overall financial risk of an investment. Increasing capital needs for construction projects, including capital-intensive projects to support the Energy Transition, are likely to tighten the supply of equity capital available across the industry, with equity investors becoming increasingly discerning regarding where they invest their capital. A combination of tightening capital

[38] S&P Global, "Utilities Face Greatest Threat as Climate Risks Intensify," September 20, 2021, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utilities-face-greatest-threat-as-climate-risks-intensify-66613890

markets and industry cash flow challenged by high capital spending will cause investors to seek compensatory returns for the elevated risk of investing in utilities' securities.

C. Current and Forecast Macroeconomic Conditions

Current and forecast macroeconomic conditions are relevant both to the determination of a generic ROE and in establishing equity thicknesses that, in combination with the ROE, meet the Fair Return Standard.

Utilities raise debt and equity in a global market influenced by macroeconomic fundamentals, capital markets and central bank policies. The cost of debt for utilities is generally observable, but the cost of equity must be estimated with an informed view of the macroeconomic and capital market factors that impact the analysis. Projections of GDP growth, inflation and interest rates are direct inputs to the cost of capital models. The cost of equity is also influenced by macroeconomic factors that impact businesses, and these factors weigh on investor confidence.

Whenever possible, risk factors should be considered quantitatively with both current and projected values. When it is not possible to quantify business or financial risk, qualitative analysis, including third-party reports such as those from credit rating agencies, equity analysts and other expert opinions are useful supplements.

LEI's Recommendation and Concentric's Response

LEI cites comparable business (volumetric, operational, regulatory, and policy risk, including Energy Transition risk) and financial (key credit metrics and credit ratings, and ability to attract debt and equity investment at reasonable rates) risks to those discussed above. In response to how these risk factors should be considered in determining the cost of capital parameters and the capital structure, LEI recommends (1) maintaining the status quo approach of reviewing business and financial risk factors if there is a significant change in the utility's risk profile; and (2) reevaluating the deemed equity thickness as a lever to address material changes in the utilities' risk profile.

Concentric concurs with LEI's recommendation to maintain a stable regulatory environment during the rate case term and reevaluate equity thickness if there are significant changes to the utilities' risk profiles. However, Concentric further concludes that the establishment of a stable regulatory environment for the entire duration of the generic cost of capital term underscores the importance of and direct reliance on setting the cost of capital and equity thickness with consideration of all the risk factors utilities will navigate in the upcoming years. LEI's recommendation implies that changes in business/financial risks would be addressed solely with an adjustment of the equity thickness. However, both the equity thickness and the cost of capital need to be evaluated to meet the Fair Return Standard.

Concentric disagrees with LEI's position regarding the impact of Energy Transition issues on the cost of capital. LEI states that utilities' cash flows are protected via various regulatory mechanisms (i.e., DVAs, Z factor, I factor, and off-ramp mechanisms). However, the risks resulting from the Energy Transition are not fully mitigated by these mechanisms and are likely to continue to increase. For example, as utilities adopt new technologies and build first-of-a-kind projects, they encounter challenges such as shortages of skilled labour and increased competition across the supply chain, in addition to technology risks. Increased operational risk may lead to funding risks if investors are not compensated fairly for their investments as capital availability tightens with more utilities entering the capital markets to fund construction projects. Securities that offer commensurate returns on the equity invested will obtain better access to capital, especially during times of elevated risk associated with the Energy Transition. Furthermore, in certain circumstances, DVAs may not be made available by the OEB. Energy Transition is further discussed in Section VII.

D. Regulatory and Rate-Setting Mechanisms

In response to **Issue #3**, a variety of regulatory and rate-setting mechanisms impact utility risk, and investors consider not only the ratemaking approach that is used to establish base rates, including the authorized rate of return, but also mechanisms such as DVAs that allow costs to be tracked and rates to be adjusted between rates applications.

Importantly, however, and consistent with the comparable investment standard, the assessment of regulatory and rate-setting mechanisms should be based not only on the consideration of such mechanisms on an absolute basis, but also based on a comparison of Ontario's regulated utilities to the proxy group companies used to establish the authorized ROE and the deemed capital structures.

In addition, the consideration of regulatory mechanisms forms only part of the business risk assessment, and a comparative assessment of other risk factors should be performed as well to understand whether the results of cost of capital analyses adequately reflect the risk profile of the subject utility. This is because the determination of a fair return, under the opportunity cost principle, necessarily involves a comparison of the business and financial risks of the company or companies for which the return is being set in relation to alternative investments. The risk comparison is performed at the operating company level because the deemed capital structure should be based on the business and financial risks of the operating utility company, not a parent holding company or other affiliate.

Certain intervenors have historically argued that the ability to earn the authorized ROE is evidence that utilities have low business risk. At a high level, Concentric agrees that regulated utilities generally have lower business risk than many of their competitive peers. This is a fundamental principle of the regulatory compact under which, in return for accepting the obligation to provide a public service and being subject to regulatory oversight, the utility is provided the opportunity to recover its prudently-incurred costs, including the cost of capital.

This regulatory model is intended to enable access to the significant capital required for utility investments on favourable terms to the benefit of customers. A demonstration that the regulated utility has actually earned its allowed return is a retrospective view of a constructive regulatory environment and a well-functioning utility, but not a measure of the business risk and financing requirements companies face in the future and not the basis on which prospective investors make investment decisions. In addition, to be meaningful, such an analysis would also need to include a comparison to the peer group companies. It is challenging to obtain comparable earned ROE data for many operating utilities due to differences in reporting requirements across jurisdictions, adjustments made to earned return data to reflect regulatory accounting, and issues such as the inclusion of goodwill and other items on the balance sheet that need to be excluded in order to make the comparison relevant. To the extent this analysis can be performed in a reasonable manner, our experience is that operating utilities in Canadian, U.S., and North American proxy groups generally earn their authorized ROE, and therefore Ontario utilities are generally not distinguishable in this regard. A simple accounting of historically earned ROEs, however, is not a basis for the determination of risk for regulated utilities.

LEI's Recommendation and Concentric's Response

LEI states that a utility's ability to recover its capital and operating costs is dependent on the regulatory mechanisms available to that utility. Perceptions of a utility's business and financial risk are affected by available regulatory mechanisms because investors value the perceived stability of future cash flows. Rating agencies, such as DBRS and S&P Global, assess regulatory risk through various regulatory mechanisms, but the ratings agencies' assessments rely on how the regulatory mechanisms available to utilities affect the stability of future utility cash flows. LEI recommends that regulatory mechanisms that can significantly impact the stability of utility cash flows should be reviewed as a component of regulatory risk.

LEI supports the current OEB policy of considering the impact of risk factors on request when there is a significant change in business or financial risk, including regulatory risk. LEI advocates for the addition of proactive impact assessments for major regulatory changes. The impact assessment would occur at the time of introduction, before the changes are implemented, which could enable the OEB to proactively adjust a utility's deemed equity thickness in response to significant regulatory changes.

Concentric generally agrees with LEI that a review of risks should consider regulatory mechanisms. Concentric notes that the proactive assessment of major regulatory changes, if performed by the OEB, should also include an assessment of regulatory decisions that could impact utilities beyond the applicant utility. Missing from LEI's recommendation, however, is the equally important step of considering the *relative* risk of Ontario utilities vis-à-vis ratemaking mechanisms. Without that comparative assessment, the comparable return standard of the Fair Return Standard cannot be satisfied. Changes in relative risk are not predicated on the establishment of significant changes in the applicant's risk, which the current OEB approach requires. While the implementation of a new regulatory mechanism may reduce a utility's absolute risk, it does not necessarily reduce the cost of capital if peer utilities have similar risk-mitigating mechanisms available to them. Further, in Concentric's experience, the regulatory regime and regulatory mechanisms should be considered in their entirety and compared to the suite of mechanisms available in peer jurisdictions.

Concentric recommends that the OEB modify its approach to assessing utility risk to incorporate comparative risk and comparable return assessments regardless of whether a significant change in risk has been demonstrated. If the deemed equity thicknesses for Ontario utilities diverge from peer equity thicknesses (which, in Concentric's analysis, they have), then the comparable return standard is not being met, even if Ontario utilities have not experienced a significant shift in risk.

E. Short-Term Debt Rate

The OEB has asked parties in **Issue #4** to comment on whether the Board should continue to follow the same process for determining the cost of short-term debt as discussed in the 2009 Report. If the response to Issue #4 is no, the Board has asked in **Issue #5** how the short-term debt rate should be set.

The deemed short-term debt cost for Ontario's utilities is determined differently for natural gas, electricity distributors and transmitters, and OPG. To summarize, for electricity distributors and transmitters, the short-term debt cost is currently determined based on a spread over the Bankers' Acceptance ("BA") rate, derived from real market quotes for issuing spreads over BA rates. The spreads are updated once a year (typically in September) when the Board obtains estimates from up to six major Canadian banks of the spread of a typical short-term loan for credit-worthy (A-rated) corporate customers, such as utilities, over the 3-month BA rate. After removing high and low results if sufficient estimates (i.e., greater than four) are procured, the average of the spreads is then applied to the current 3-month BA rate to determine the utilities' short-term debt rate for rate-setting purposes. The current 3-month BA rate is calculated as the month-long average of the calendar month three-months in advance of the rates' effective date, sourced by the Canadian Investment Regulatory Association. For example, for rates effective January 1, 2024, the deemed short-term debt cost rate was calculated as 6.23% and was determined as follows:

Sept. 2023 Average 3-month Bankers' Acceptance Rate = 5.228%	+	Average spread estimates from major Canadian Banks received Sept. 2023 = +100.000 bps	=	6.23% Deemed Short-Term Debt Rate for rates effective Jan. 1, 2024

For natural gas distributors and OPG, the applicant natural gas utility forecasts its own cost of short-term debt for the test year, which is subject to review prior to implementation in rates. The Board noted in its 2009 Report that short-term debt was typically used to true-up a gas utility's deemed capitalization to its actual capitalization, and therefore the magnitude of short-term debt relative to the entire capitalization was relatively small.[39]

In making these methodological decisions in the 2009 Report, the Board left open to discussion whether these methodologies could be subject to future change. In its January 2016 Staff Report, the OEB Staff stated that the process for determining the deemed short-term debt cost rate had been "working well" and that there had been "no concerns" about the methodology, and therefore saw no reason to change the process at that time.[40] Concentric recommends continuing to use the same benchmark plus spread framework. However, in response to the discontinuation of the BA market on June 28, 2024, transitioning to a measure of short-term loan rates, such as a three-month average of the Canadian Overnight Repo Rate Average ("CORRA"), is the most reasonable alternative. The methodology would subsequently use an A-rated corporate short-term loan spread over the CORRA rate instead of the BA rate.[41]

LEI's Recommendation and Concentric's Response

LEI notes that in October 2023 the Canadian Fixed-Income Forum ("CFIF") recommended a path to winding down the BA market because BA's will no longer be issued by major Canadian banks after June 2024. As such, LEI finds that the 3-month BA is no longer an appropriate component of the OEB's short-term calculations. LEI, therefore, recommends that the OEB consider the average of 3-month CORRA futures rates for the next 12-month period. LEI further recommends that the spread for a R1-low rated utility over CORRA should be applied in the short-term debt rate calculation, with the spread to be determined from an annual confidential survey of 6-10 banks. Lastly, LEI recommends that the deemed short-term debt rate should be applied as a cap for all utilities. Concentric agrees with LEI's recommendation of transitioning to replacing the BA rates with CORRA rates in the deemed short-term debt rate methodology. Concentric disagrees in principle, however, with the application of a cap, as actual costs of borrowing can deviate from the deemed debt rate for reasons that are outside of the control of the utility and does not believe a

39 EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (OEB Report), December 11, 2009, p. 55.

40 See OEB Staff Report, EB-2009-0084, issued January 14, 2016, p. 8-9.

41 Concentric notes that to the extent OEB-regulated utilities can reasonably achieve A or A-ratings under the regulatory framework, then the use of an A-rated spread is generally appropriate. However, to the extent utilities cannot reasonably achieve such ratings, a BBB spread may become more applicable.

change to the OEB's current practice is warranted or necessary. While the deemed debt rate can inform the OEB's assessment of utility-specific debt rates, the rote application of a cap could result in utilities not being provided the opportunity to recover prudently-incurred costs. Concentric specifically disagrees with the extension of the cap to Enbridge Gas and OPG under LEI's proposal. The continued use of the forecasted rates by the utilities will allow the utilities, in circumstances where their cost of debt is expected to exceed the cap, for reasons of risk differentials (e.g., due to timing differences or if a utility faces risk differentials to a R-1 rating) to demonstrate why their utility-specific debt cost is reasonable.

F. Long-Term Debt Rate

The OEB has asked parties in **Issue #6** to comment on whether the Board should continue to follow the same process for determining the cost of long-term debt as discussed in the 2009 Report. If the answer to Issue #6 is no, the Board has asked in **Issue #7** how the long-term debt rate should be set.

In general, the long-term cost of debt for ratemaking purposes is based on embedded costs, subject to the use of a deemed long-term cost of debt in certain circumstances for electricity distributors. The Board noted in its 2009 Report that the deemed long-term debt rate "will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances."[42] For example, for affiliate debt with a fixed rate, the deemed long-term debt at the time of issuance will be used. For affiliate and third-party variable-rate debt, as well as debt callable on demand within the test year period, the long-term debt rate will be a ceiling on that debt's rate. For debt callable on demand outside the test year period, it will be treated as if it is not callable. The Board also noted that "the long-term debt guidelines relating to electricity distribution utilities are expected to evolve over time and are expected to converge with the process used by the Board to determine the amount and cost of long-term debt for natural gas distributors."[43]

The Board determines the deemed long-term debt rate formulaically based on the 30-year Government of Canada ("GOC") bond yield forecast, plus the average historical spread between A-rated Canadian utility bond yields and 30-year Government of Canada bond yields. The 30-year GOC

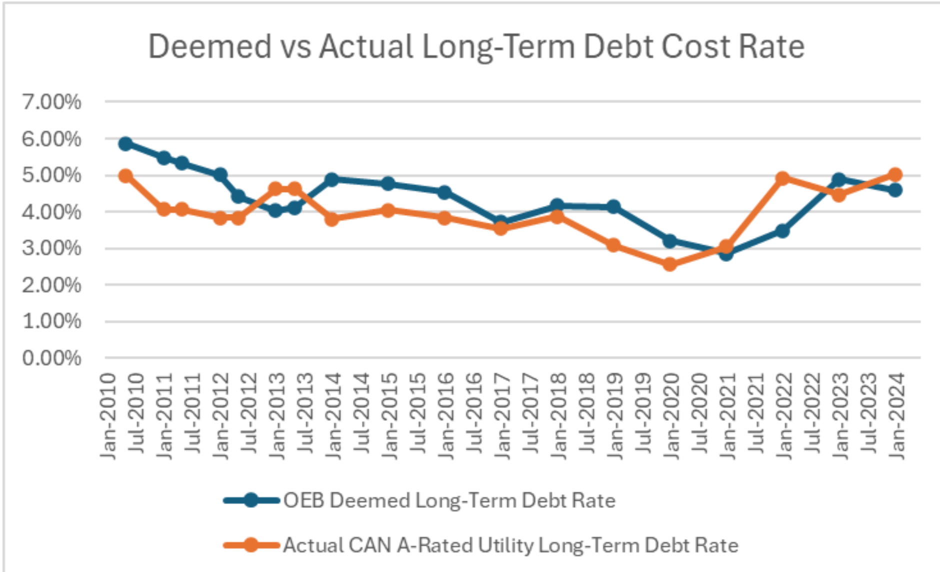
42 EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (OEB Report), December 11, 2009, p. 53-54.
43 Ibid, p. 52.

bond yield forecast is determined using a forecast of the 10-year GOC bond yield sourced by Consensus Forecasts and adding the historical spread between 10- and 30-yr GOC bond yields. The 30-year GOC bond yield forecast and both spreads (the 10-year to 30-year spread, as well as the A-rated utility to 30-year spread) are determined by averaging the business days of the month three months in advance of the new rates' effective date. For example, for rates effective January 1, 2024, the deemed long-term debt cost rate was calculated as 4.58% and was determined as follows:

10-Year GOC Bond Yield Forecast, sourced by Consensus Forecasts, as of Sept. 2023 = 3.250%	+	Historical 30-year GOC to 10-Year GOC Spread for the month of Sept. 2023 = -19.6 bps	+	Historical Canadian A-Rated Utility Bond Yield to 30-Year Bond Yield Spread for the month of Sept. 2023 = +152.5 bps	=	Deemed Long-Term Debt Rate for rates effective Jan. 1, 2024 = 4.58%

Concentric compared the OEB's deemed long-term debt rates published since 2010 with actual Canadian utility long-term debt rates tracked by a Bloomberg index of 30-year Canadian A-rated utility bonds. The actual long-term debt rates were averaged annually to compare to the calendar rate years in which the deemed long-term debt rates were effective. Since 2010, the OEB's deemed long-term debt cost rate has had periods of being above and below the Bloomberg index, and averaged 40 bps higher than the index. Both measures may understate actual debt costs if issuance costs are not included.

Figure 2: Deemed vs Actual Long-Term Debt Cost Rate



Concentric also looked to other Canadian jurisdictions to determine if other approaches may be helpful in evaluating Ontario's deemed long-term debt rate formula. In Alberta, the Alberta Utilities Commission ("AUC") states that "the cost of debt (or the interest rate a utility pays on debt) is not typically set by the AUC, but is determined in the market, based on who is willing to lend the utility money." [44] In the 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, the AUC uses the actual embedded debt cost to determine reasonable long-term debt rates.[45] The AUC's Determination of the Cost-of-Capital Parameters in 2024 and Beyond includes a comparative analysis of the embedded average debt rate among distribution and transmission utilities in Alberta, in which the AUC determined an embedded average debt rate of 4.20 percent is reasonable. This figure was higher than the overall simple average debt rate for the utilities analyzed, which was 4.09 percent based on 2023 data; however, the AUC errs on the conservative side due to the resulting lower EBIT coverage and funds from operations coverage ratios.[46]

---

44 Alberta Utilities Commission website, "Rate of Return", accessed May 30, 2024. https://www.auc.ab.ca/rate-of-return/

45 Alberta Utilities Commission, 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, October 4, 2023.

46 Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond, October 9, 2023.

In British Columbia, in its May 2013 Generic Cost of Capital Decision, the British Columbia Utilities Commission ("BCUC") found that "the cost of deemed long-term debt (rate and term) for each utility should be addressed separately on a case-by-case basis."[47] In addition, the BCUC found that the following methodology should be used as a "guideline" going forward for setting the deemed long-term debt rate applicable to a small utility without third-party debt:

1. *Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity. A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB (low), with the deemed debt cost set on this basis.;*

2. *Determine a Government of Canada (GoC) bond yield reflecting the proposed term of debt that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of the two. The selected benchmark should reflect the long-term nature of utility assets, contractual terms and available debt terms.*

3. *Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond.*[48]

The OEB's approach to the deemed long-term debt cost rate is similar to and a specific form of the BCUC approach outlined above (i.e., the Board's deemed long-term debt rate methodology specifies a deemed credit rating of "A" in Step 1, determines the 30-year Long Canada Bond Forecast ("LCBF") as the reasonable benchmark in Step 2, and applies the appropriate historical spread, as in Step 3).

Concentric finds that the general use of embedded debt costs of each individual utility company is reasonable and appropriate for previously-incurred debt, and further that utilities should be allowed to forecast debt rates for debt that will be incurred during the rate plan, subject to review and approval by the OEB.

---

47 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision May 10, 2013, p. 110.

48 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision May 10, 2013, p. 107-108.

If the Board were to modify its approach to the deemed long-term debt cost rate, Concentric suggests considering a long-term debt rate benchmarking intended to confirm that the Board's deemed long-term debt cost rate is within reasonable error-bounds of actual utility debt costs. We further recommend adopting the same approach we recommend to the ROE formula (discussed in Section VI with reliance on bank forecasts for the 30-year bond yield versus the current approach that relies on the Consensus 10-year forecast plus a 10-30 spread. In either case, we recommend using 90-day averages for spreads versus the current month of September only.

LEI's Recommendation and Concentric's Response

LEI recommends considering publicly available reputable sources for 30-year bond yield forecasts for the Long Canada Bond Forecast, and further using Bloomberg's BVCAUA30 BVLI Index (12-month trailing average) for the A-rated utility spread over the Long Canada Bond Forecast. Lastly, LEI recommends using the deemed long-term debt rate as a cap for debt costs for all jurisdictional utilities, not just electricity distributors and transmitters.

Subject to our other recommendations above, we agree with LEI regarding the use of 30-year forecasts versus the current approach that relies on the Consensus 10-year forecast plus a 10-30 spread.

Concentric does not agree, however, about the automatic application of a cap on debt costs. The rejection of a uniform application of the cap would be consistent with the OEB's findings in EB-2010-0008, where the OEB found that OPG's actual cost of debt was more appropriate for rate setting purposes than a deemed cost of debt, and that the "deemed long-term debt rate is only intended to apply where a utility has no actual long term debt (or where the debt is held by an affiliate)."[49] Further, capping all utilities at the deemed debt cost would not be reflective of the spectrum of credit ratings assigned to regulated utilities. With the index constituent bonds comprising issuances rated A+, A, and A-, entities like OPG that are rated on the lower end of this spectrum would not be appropriately compensated for their cost of debt, given that each notch lower on the credit rating scale entails a higher cost of funding. As with our findings regarding the deemed short-term debt rate, Concentric does not believe a change to the OEB's current practice in this regard is warranted or necessary, and utilities should continue to be provided with the opportunity to forecast debt rates for debt that will be incurred during a rate plan. While the

49 Decision with Reasons (EB-2010-0008), March 10, 2011, p. 125.

deemed debt rate can inform the OEB's assessment of utility-specific debt rates, the rote application of a cap could result in utilities not being provided the opportunity to recover prudently-incurred costs.

The OEB has also asked parties in **Issue #8** to comment on whether the Board should allow Ontario's utilities to recover transaction costs associated with the issuance of long-term debt, consistent with the current approach that was adopted in the 2009 Report. In Concentric's view, debt issuance costs are a legitimate cost of funding the operations of the utilities and should be recovered in rates through the embedded cost of long-term debt, as is the OEB's current practice. Debt issuance costs include fees and expenses for underwriting the debt security, legal services, security exchange registration, and fees paid to credit rating agencies.

Transaction costs are unavoidable expenses that arise during regular business operations, thereby raising the overall costs of operations and capital expenditures for utilities. Total underwriting costs can vary across debt instruments and their tenures, with longer tenured debt resulting in higher fees for the utility, reaching upwards of 100 bps of the total debt instrument amount. For example, Hydro One's January 2023 sustainable bond issuance of $1.05 billion cost the utility $4.3 million, or approximately 41 basis points of debt raised[50].

Other jurisdictions have adopted the allowance for debt transaction cost recovery. In the U.S., for example, FERC allows utilities to recover debt issuance costs through the deferred debits account, which amortizes the debt issuance costs over the life of the security using the bonds outstanding method (i.e., which approximates the effective interest method). In Concentric's experience, a similar approach is commonly used in many U.S. state jurisdictions.

50 For example, Hydro One's financing cost of 41 basis points, or approximately $4.3 million, is a one-time fee that is amortized over the life of the debt instrument, adding a small incremental expense to the borrower's total debt expense.

LEI's Recommendation and Concentric's Response

Citing "irregularity in frequency and amount of debt issuance," LEI recommends the OEB change its current approach of allowing utilities to account for transaction costs using the "effective interest rate method," and instead account for transaction costs as operating expenses. We disagree that a change is warranted, and especially for the reasons cited by LEI. In Concentric's experience, the common approach in North America to accounting for transaction costs is through the effective interest method, and LEI's jurisdictional review supports that conclusion. The fact that debt issuances may be irregular or of different amounts is irrelevant to the recovery of prudently-incurred transaction costs, which, like the interest paid over the life of borrowings, are part of the cost of debt and should be recognized over the life of the debt for which the costs were incurred. LEI's approach puts Ontario utilities at risk of not recovering these costs simply because they were not incurred in the test year or are expected to be incurred over the rate plan. LEI's approach, therefore, would appear to go against LEI's principles of "transitioning away from the status quo only if the associated benefits are material," and "fairness in approach to consumers and utilities." Concentric has further concerns that treating transaction costs as operating expenses may not be compliant with International Financial Reporting Standards ("IFRS") and would therefore cause a difference between regulatory reporting and financial reporting. As such, Concentric recommends no change to the Board's method for accounting for transaction costs.

G. Variances from Deemed Capital Structure

In **Issue #9**, the Board has asked the parties what the implications are of variances from the deemed capital structure (i.e., notional debt and equity) and how those variances should be considered in setting the cost of long-term debt. Concentric's view is that for rate-setting purposes, the deemed capital structure should determine the debt and equity costs that are recovered in rates, and that Ontario's regulated utilities should continue to be given the discretion to manage their actual capital structure within reasonable bounds. This is particularly important for the periods between when the OEB assesses each utility's ratemaking capital structure, as it is important for the utilities to be given latitude in managing their credit profiles and accessing the debt and equity markets when conditions warrant.

LEI's Recommendation and Concentric's Response

LEI recommends continuation of the OEB's status quo approach regarding this issue, which LEI describes as "consider deemed capital structures regardless of actual capital structures." As described above, Concentric agrees with this recommendation.

V. ESTIMATING THE COST OF EQUITY

A. Overview

In **Issue #10**, the Board asks what methodology the OEB should use to produce a return on equity that satisfies the Fair Return Standard. In December 2009, the Board modified the existing ROE formula, which is based on an ERP approach, to adjust the authorized ROE annually depending on changes in both government bond yields and the utility credit spread. The reason for including the utility credit spread was to address concerns that the previous formula was not producing a fair return in part because it did not consider utility specific risk, which is not captured in GOC bond yields.

To address this question, Concentric performed analyses of macroeconomic and proxy company market data using several reliable approaches to estimating ROE based on models relied on across North American jurisdictions. Concentric also responds to LEI's ROE analyses and recommendations.

As discussed in more detail in Section VI of our Report, based on Concentric's analysis, we find that the OEB's ROE formula currently is not producing an authorized ROE that meets the Fair Return Standard. For that reason, our recommendation is that the Board re-set the authorized base ROE to 10.0 percent, based on the results of the DCF, CAPM and Risk Premium models described in this section. Further, and as previously found by the Board, OPG faces a different and heightened level of risk compared to distributors and transmitters. As such, the base ROE recommendation of 10.0 percent understates the ROE for OPG. In addition, the OEB has previously found that there is a heightened risk of nuclear generation relative to hydroelectric generation,[51] which is important to consider as OPG embarks on first-of-a-kind nuclear projects in addition to refurbishing its existing nuclear units. There are also no direct comparators in the proxy groups analyzed by Concentric for OPG's pure-play rate-regulated generation operations. Rather than set alternative generic ROEs in the proceeding, however, Concentric recommends that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied as part of its authorized ROE, the OEB consider that proposal at its discretion as part of that proceeding. Lastly, the Board should adopt a process whereby the ROE

51 See, e.g., EB-2016-0152, Decision and Order, December 28, 2017, p. 102.

formula is reviewed against the results of generally-accepted financial models at least every five years to ensure that the return satisfies the legal requirements of the Fair Return Standard.

B. Overview of Economic and Capital Market Conditions

Utilities raise debt and equity in a global market influenced by macroeconomic fundamentals, capital markets and central bank policies. The cost of debt for utilities is generally observable, but the cost of equity must be estimated with an informed view of the macroeconomic and capital market factors that impact the analysis.

Error! Reference source not found. Figure 3 below provides a comparison of key economic and market indicators, including betas (both raw and adjusted) in November 2009 (immediately prior to the Board's 2009 Report) to those in May 2024 (when our analysis in this proceeding was performed.)

Figure 3: Comparison of Interest Rates, Inflation, and Other Market Indicators

Indicator	November 2009	May 2024
Bank of Canada Overnight Rate	0.25%	4.75%
10-year Government of Canada bond	3.40%	3.64%
30-year Government of Canada bond	3.94%	3.51%
A-rated Canadian utility bond	5.41%	4.86%
GDP Growth Forecast – Consensus Economics – Canada	4.44%	3.84%
Consumer Price Inflation – Canada	1.0%	2.7%
U.S. Federal Reserve – Fed Funds Rate	0.0-0.25%	5.25-5.50%
10-year U.S. Treasury bond	3.40%	4.48%
30-year U.S. Treasury bond	4.31%	4.62%
Moody's A-rated utility bond	5.63%	5.74%
GDP Growth Forecast – Consensus Economics – U.S.	5.06%	4.04%
Consumer Price Inflation – U.S.	1.8%	3.3%
5-year Bloomberg Beta (raw)[52]	0.64	0.82
5-year Bloomberg Beta (adjusted)[53]	0.76	0.88

As shown in the above Figure, while interest rates on 30-year Canadian government and utility bonds have declined since November 2009, most other market indicators have increased. Specifically, monetary policy in both Canada and the U.S. is significantly more restrictive in May 2024 in response to higher inflation as compared to November 2009, when central banks were seeking to stimulate the global economy following the financial crisis. Importantly, utility betas (both raw and adjusted) have increased since November 2009 – a key measure of the market's view of utility risk. Overall, these market indicators support our recommendation to reset the base authorized ROE for Ontario's electric and gas utilities at 10.0 percent.

[52],[54] Concentric took an average of the 5-year raw and adjusted Bloomberg Betas for the North American Proxy Group using the two time periods observed in Figure 3.

C. Selection of Proxy Companies

1. Proxy Group Selection

Because the ROE is a market-based concept, it is necessary to establish a group of companies that is both publicly traded and comparable to Ontario's utilities in fundamental business and financial respects to serve as a "proxy" for purposes of ROE estimation. Notwithstanding the care taken to ensure comparability, market expectations with respect to future risks and growth opportunities vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. At issue, then, is how to select an ROE estimate in the context of that range. That determination must be based on an assessment of the company-specific risks relative to the proxy group and the use of informed judgment.

2. Proxy Group Screening

We developed six proxy groups for the ROE analysis to evaluate the results of multiple analytical approaches applied to different sectors and geographical groupings. In doing so, we note that OPG is unique as an electric generator. While several of the companies in our North American proxy group (described below) own regulated electric generation assets, they do not entirely capture the unique business and financial risks of OPG as a pure-play generator.

The first proxy group is comprised of publicly traded, regulated Canadian electric and natural gas utility companies. Recognizing there are few publicly traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. TC Energy (formerly TransCanada) has been excluded due to the risk profile of the TransCanada Mainline, which differs from gas distribution operations. Algonquin Power and Utilities Corp. was also excluded because the company did not have positive earnings growth rate forecasts from more than one source and announced a reduction of its dividend in January 2023.[54]

[54] Having positive earnings growth rate projections from at least two sources and consistently paying quarterly cash dividends are necessary for inclusion in the DCF model.

Figure 4: Canadian Proxy Group

Company	Ticker
AltaGas Limited	ALA
Canadian Utilities Limited	CU
Emera, Inc.	EMA
Enbridge, Inc.	ENB
Fortis, Inc.	FTS
Hydro One Ltd.	H

The second proxy group is comprised of like-risk U.S. electric utility companies. To obtain companies of comparable-risk, we performed a number of screens to determine a group of electric utilities with similar risk profiles to Ontario's electric utilities. We started with the 36 companies The Value Line Investment Survey ("Value Line") classifies as Electric Utility Companies. From that group, we further screened for companies that:

a) Have credit ratings of at least BBB+ from S&P Global or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends with no reductions or eliminations in the past two years;

c) Have positive earnings growth rate projections from at least two sources;

d) Derived at least 70 percent of operating income from regulated operations in the period from 2021-2023;

e) Derived at least 80 percent of regulated operating income from electric utility service in the period from 2021-2023; and

f) Were not involved in a merger or other significant transformative transaction during the evaluation period.

The following U.S. electric utility companies meet our screening criteria:

Figure 5: U.S. Electric Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Eversource Energy	ES
Exelon Corp.	EXC
Evergy, Inc.	EVRG
NextEra Energy Corp	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

The third proxy group is comprised of like-risk U.S. gas distributors. To obtain companies of comparable risk, we performed a number of screens to determine a group of gas utilities with similar risk profiles to Ontario's gas distribution utilities. Starting with the ten companies Value Line classifies as Natural Gas Distribution Companies, we further screened for companies that:

a) Have credit ratings of at least BBB+ from S&P Global or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends with no reductions or eliminations in the past two years;

c) Have positive earnings growth rate projections from at least two sources;

d) Derived at least 65 percent of operating income from regulated operations in the period from 2021-2023;

e) Derived at least 90 percent of regulated operating income from natural gas distribution utility service in the period from 2021-2023; and

f) Were not involved in a merger or other significant transformative transaction during the evaluation period.

The following U.S. gas distribution companies meet our screening criteria:

Figure 6: U.S. Gas Proxy Group

Company	Ticker
Atmos Energy Corp	ATO
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

In the current environment, gas and electric utilities face different risks, with gas distributors facing load risks from decarbonization, and electric utilities facing risks associated with the Energy Transition demand and associated capital needs, new requirements for electric transmission, and competition from distributed energy resources. This represents a shifting of relative risk profiles from prior periods, and the use of separate electric and gas proxy groups allows us to test the electric versus natural gas groups for any market-based differentials revealed in the results.

The fourth proxy group is a combined North American Electric proxy group that includes all Canadian and U.S. electric utility companies determined to be risk comparable to Ontario's electric utilities. As noted previously, OPG, as a generation-only utility, faces unique risks as compared to the electric proxy group, as the proxy companies that own generation also have lower risk transmission and distribution assets.

Figure 7: North American Electric Proxy Group

Company	Ticker
Canadian Utilities Limited	CU
Emera Corp.	EMA
Fortis, Inc.	FTS
Hydro One Ltd.	H
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Eversource Energy	ES
Exelon Corp.	EXC
Evergy, Inc.	EVRG
NextEra Energy Corp	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corp	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

The fifth proxy group is a combined North American Gas proxy group that includes all Canadian and U.S. gas utility companies determined to be risk comparable to Ontario's gas distribution utilities.

Figure 8: North American Gas Proxy Group

Company	Ticker
AltaGas Ltd.	ALA
Canadian Utilities Limited	CU
Enbridge Inc.	ENB
Fortis Inc.	FTS
Atmos Energy Corp.	ATO
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

Lastly, the sixth proxy group is a North American Combined proxy group that consists of all of the companies in the Canadian, U.S. Electric and U.S. Gas proxy groups. See Exhibit CEA-2 for our proxy group screening results.

3. Use of North American Proxy Groups

In its December 2009 Report, the OEB was among the first regulators in Canada to find that the use of U.S. companies and U.S. data to set the authorized returns for Canadian electric and gas utilities is appropriate. In support of this determination, the Board made a number of findings with regard to the proxy group that remain relevant today, including:[55]

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

> *Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money." In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. The analyses of Concentric Energy Advisors and Kathy McShane of Foster Associates Inc. are particularly relevant in this regard, and substantially advance the issue of establishing comparability to meet the requirements of the FRS.*

55 Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 21-23.

> *The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit... The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation.*

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

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

In a 2016 proceeding involving OPG, however, the OEB noted that both Concentric (presenting information on behalf of OPG) and the Brattle Group (presenting information on behalf of the OEB Staff) should have made adjustments to the comparator group data "to account for the substantially lower common equity ratios allowed regulated utilities in Canada."[56] In considering this matter in this report, Concentric observes that allowed equity ratios for U.S. utilities generally remain higher than deemed equity ratios for Canadian utilities. However, this wide differential is not currently explained by differences in risk. Rather, Canada and the U.S. are both part of an integrated North American capital market where equity and debt investors do not perceive meaningful risk differentials between regulated utility investments in the two countries. This has been further supported more recently by regulators in British Columbia and Alberta.

Specifically, both the BCUC and the AUC have accepted the use of a North American proxy group comprised of utility companies in both Canada and the U.S. to set the authorized ROE for utilities

[56] Ontario Energy Board, Decision and Order EB-0216-0152, Ontario Power Generation Inc., December 28, 2017, p. 109.

under their jurisdiction. The BCUC explained its rationale for using a North American proxy group as follows:

> *For the reasons outlined above, we find the use of the Canadian proxy groups and US proxy groups alone to be inferior to that of using a North American proxy group which has a reasonable mix of both Canadian and US comparators, and the averaging of the results of these three groups to be a poor compromise. On balance, we find that having a proxy group of North American comparators trumps any jurisdictional or structural differences. In making this determination, we rely on the facts that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establishing a comparable ROE.*[57]

The recent BCUC decision is consistent with our view that equity investors and credit analysts consider the utility industry as a North American industry, with Canadian companies competing for capital with similar risk companies in both countries.

The AUC also recently developed a set of screening criteria for purposes of selecting a proxy group of companies that could be used to estimate the cost of equity for Alberta's electric and gas utilities.[58] The large majority of companies chosen by the AUC for the comparator group (28 out of 33 companies, or almost 85 percent) were either U.S. electric or U.S. gas utilities (or both). In addition, several of the Canadian companies in the AUC's comparator group have significant U.S. operations, including Emera, Fortis, and Algonquin Power. This highlights the extent to which the utility industry has clearly become a North American industry from an investor and allocation of capital viewpoint. Canadian regulators have increasingly accepted the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. Additionally, the development of a proxy group comprised entirely of Canadian utilities is challenged by the small number of publicly traded utilities in Canada and the fact that several of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated utility service.

4. Integration of Canadian and U.S. Capital Markets

The OEB considers the use of both U.S. and Canadian market and company data, as discussed above. It is also important, however, to consider the comparability of the risk environment from an investor's perspective, as risk drives return expectations. This is especially necessary in the Energy

57 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, p. 16.
58 AUC Decision 27084-D02-2023, October 9, 2023, at para 99-104.

Transition, where investors will seek to optimize returns for a given level of risk taking. In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors distinguish between risks on a country-to-country basis, factoring in the comparability of the economic, business, regulatory and political environments.

Country-specific economic, business and political conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by The Economist Intelligence Unit, rates Canada and the U.S. the same from an overall country risk perspective. Both are rated as A, with AAA being the highest rating.[59] The Economist provides the following description of its country risk ratings:

> *The Economist Intelligence Unit's Country Risk Service produces reports on 100 emerging markets and 20 OECD countries. These country-specific reports are complemented by this Risk ratings review, which analyses regional and global risk trends. The main focus of the ratings is on three risk categories to which clients can have direct exposure: sovereign risk, currency risk and banking sector risk. We also publish ratings for political risk and economic structure risk, as well as an overall country credit rating. The ratings are measured on a scale of 0-100. Higher scores indicate a higher level of risk. The scale is divided into ten overlapping bands: AAA, AA, A, BBB, BB, B, CCC, CC, C, D. In the Risk ratings review, ratings for a region are defined as the unweighted average of the ratings for all the countries being assessed in that region.*[60]

Figure 9 summarizes the country risk ratings for Canada and the U.S. as of August 2021.

[59] The Economist Intelligence Unit, Country Risk Service, Risk Ratings Review, August 2021, p. 30.
[60] Ibid, p. 28.

Figure 9: Country Risk Ratings

	Canada	U.S.
Sovereign Risk Rating	A	AA
Currency Risk Rating	A	A
Banking Sector Risk Rating	AA	A
Political Risk Rating	AAA	AA
Economic Structure Risk Rating	A	A
Overall Country Risk Rating	A	A

This suggests that from a country risk perspective, Canada and the U.S. are directly comparable. This assessment is confirmed in country risk reports from Allianz indicating that both Canada and the U.S. were ranked AA1 as of January 2024.[61]

The magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. According to the U.S. Department of State: "The United States and Canada enjoy the world's most comprehensive trading relationship, which supports millions of jobs in each country. Canada and the U.S. are each other's largest export markets, and Canada is the number one export market for more than 30 U.S. States."[62] Canada is currently the U.S.'s second largest goods trading partner overall with $773 billion in total (two way) goods trade during 2023.[63] Two-way trade averaged $US 2.1 billion per day in 2023 and during the first four months of 2024. This is an indication of the high degree of economic integration between the two economies.

Exhibit CEA-3 presents several measures of the overall economic and investment environment in Canada and the U.S. On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries.

61 Source: Country Risk Report Canada (allianz.com) , Country Risk Report United States (allianz.com).
62 U.S. Department of State, https://www.state.gov/u-s-relations-with-canada.
63 https://www.census.gov/foreign-trade/balance/c1220.html.

Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (in terms of economic growth, inflation, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparable risk utilities in the two countries. Our cost of capital analysis is framed by the conclusion that Canada and the U.S. have comparable macroeconomic and investment environments. Importantly, this is not a new phenomenon or novel interpretation of the data. For instance, in 1977, the National Energy Board ("NEB", now the "CER") reached a similar conclusion when it found: "the opportunity cost of capital is not significantly different between Canada and the U.S." The NEB concluded: "Based upon its assessment of overall risk of the Company (IPL) relative to U.S. and Canadian industrials, the Board concludes that the cost of equity should be equal to, or slightly less than, the opportunity cost of investments in such (U.S.) companies."[64] Therefore, based on the factors discussed above, we consider both Canadian and U.S. proxy companies for our analysis without making an adjustment for differences in risk between the two countries.

D. Use of Multiple Methodologies to Estimate ROE

The cost of equity cannot be directly observed in the same way as the cost of debt or preferred stock. Analysts use multiple approaches to estimate the cost of common equity, including the DCF model, the CAPM, and the Risk Premium model. The required ROE can be estimated using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Quantitative models produce a range of results from which the market-required ROE is determined. A consideration in determining the ROE is to ensure that the methodologies employed reasonably reflect investors' *forward-looking* views of financial markets in general, and the subject company (in the context of the proxy groups) in particular.

No financial model can exactly pinpoint the "correct" ROE; rather, each test brings its own perspective and set of inputs that inform the estimate of the ROE. Consistent with the *Hope* standard, it is "the result reached, not the method employed, which is controlling."[65] Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent limitations and should not be relied upon individually without corroboration from other approaches.

64 National Energy Board, RH-2-76 Part II, PDF p. 144-145.
65 See Hope Natural Gas v. Federal Power Commission.

Regardless of which analyses are used to estimate the investor-required ROE, analysts must apply informed judgment to assess the reasonableness of the results and to determine the appropriate weighting to apply to the results under prevailing capital market conditions.

In the financial textbook, Financial Management Theory and Practice, Dr. Eugene F. Brigham explains the need to use multiple models to estimate the cost of equity as follows:

> *In practical work, it is often best to use all three methods – CAPM, bond yield plus risk premium, and DCF – and then apply judgment when the methods produce different results. People experienced in estimating equity capital costs recognize that both careful analysis and some very fine judgments are required.*[66]

The OEB specifically supported the use of multiple methodologies to estimate the equity risk premium in its 2009 Report, stating:

> *The Board agrees that the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP.* [67]

Other Canadian utility regulators, including the AUC[68] and the BCUC, have also recognized the benefits of using multiple methodologies to determine a fair ROE. In particular, the BCUC recently determined that it was appropriate to base the authorized ROE for FortisBC Energy Inc. (a gas distribution utility) and FortisBC Inc. (an electric utility) on an equal weighting of the Multi-Stage DCF model, the CAPM using an average market risk premium, and the U.S. Risk Premium analysis.[69] That is the same approach we have followed in this report.

We have considered the results of the DCF model (both constant growth and multi-stage forms), the CAPM, and the Risk Premium model to estimate the ROE for the various Canadian, U.S., and North

66 Dr. Eugene F. Brigham, Financial Management Theory and Practice, Fourth Edition, copyright 1985, p. 256.

67 Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, p. 26.

68 Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond, Decision 27084-D02-2023, October 9, 2023, p. 38.

69 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23, September 5, 2023, p. 136.

American comparator groups. We have also compared the results of our analyses to authorized returns for other regulated utilities in both Canada and the U.S. The following section of our report discusses the inputs and results of each model in more detail, starting with the DCF model.

E. Discounted Cash Flow ("DCF") Model

The premise underlying the DCF model is that investors value an investment according to the present value of its expected cash flows over time. The standard DCF model is shown in Equation [1]:

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \quad [1]$$

where:

P = the current stock price
g = the dividend growth rate
D_n = the dividend in year n
r = the cost of common equity.

Assuming a constant growth rate in dividends, the model is commonly simplified to compute the ROE, as shown in Equation [2]:

$$r = \frac{D}{P} + g \quad [2]$$

Stated differently, the cost of common equity is equal to the dividend yield plus the expected dividend growth rate.

The Constant Growth DCF model requires the following assumptions:

- a constant average growth rate for earnings and dividends;
- a stable dividend payout ratio;
- a constant price-to-earnings multiple; and
- a discount rate greater than the expected growth rate.

As discussed later in the report, other forms of the DCF model do not rely on the assumption of constant growth in perpetuity.

We discuss each of the DCF model variables in the subsections below.

1. Dividend Yield

As shown in equation [3], the dividend yield component of the DCF model is calculated as follows:

$$[3] \quad Y = \frac{D_0(1+0.5g)^1}{P_0}$$

One half year's growth rate is applied to the annual dividend rate to account for increases in quarterly dividends at different times throughout the year. It is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period and does not overstate the aggregated dividends to be paid during that time.

The dividend yields were calculated for each company in the respective proxy groups by dividing the current annualized dividend by the average stock price for each company for the 90 trading days ended May 31, 2024. Those dividend yields are multiplied by one-half the growth rate to reflect expected future dividend increases.

2. Growth Rate Estimates

In considering the appropriate growth rate for the DCF model, the most relied upon indicator of investors' expectations is analysts' estimates of future earnings growth. We have relied on earnings growth estimates from S&P Capital IQ Pro (formerly SNL Financial), the Value Line, Zacks Investment Research ("Zacks"), and Thomson First Call (as reported on Yahoo! Finance) for the companies in the respective proxy groups. LEI has also relied on earnings per share growth rates from S&P Capital IQ in its DCF analysis. We rely on multiple sources to best inform the overall estimate of earnings growth for each company. Those growth rates are shown in Exhibit CEA-4.

Investors typically rely on projected earnings growth rates rather than other measures of growth such as dividend growth rates for several reasons. First, although the DCF model is based on dividend growth, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order to reduce the long-term growth rate to a single measure, as required in the Constant Growth DCF model, it is necessary to assume a constant payout ratio, and that earnings per share, dividends per share and book value per share grow at a constant rate. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' forecasts of earnings growth are widely available, whereas dividend and book value growth rates are generally available only from Value Line.[70]

Some intervenors and utility regulators in Canada have expressed concern that analysts' earnings growth rates may be overly optimistic, and LEI makes this assertion in its report in this proceeding. If optimism bias were present in analysts' earnings forecasts, it could create an upward bias in the estimated cost of capital that results from the DCF approach. To control for this concern, some analysts have used GDP growth as a proxy for long-term earnings growth. We, however, do not share the view that analysts' earnings growth rates are biased, as discussed below.

In order to assess whether analyst earnings growth rates are reasonable relative to GDP growth, we compared the actual earnings and dividends per share growth rates (for the companies in the four proxy groups for which the required data are available) to historical and projected GDP growth over the period from 2009-2023. These results are shown in the Figure 10 below.

Figure 10: Utility Earnings, Dividend and GDP Growth Comparisons

Proxy Group	[1] Historical EPS Growth Rate, 2009-2023	[2] Historical DPS Growth Rate, 2009-2023	[3] Historical GDP Growth Rate, 2009-2023	[4] Forecast EPS Growth Rate, 2027-2029	[5] Forecast Nominal GDP Growth Rate, 2030-2034
North American Electric Proxy Group	4.36%	5.44%	4.61%	6.00%	4.00%
North American Gas Proxy Group	5.81%	5.80%	4.55%	4.84%	3.94%
North American Combined Proxy Group	4.62%	5.44%	4.60%	5.98%	3.99%
Average	**4.93%**	**5.56%**	**4.59%**	**5.61%**	**3.98%**

Notes:
[1] - [2] Source: Value Line Reports, dated April 19, 2024, May 10, 2024, May 24, 2024, June 7, 2024, and June 14, 2024; median results
[3] Source: Federal Reserve Bank of St. Louis Economic Data for Canada and the U.S.
[4] Source: Zacks, SNL, Value Line, and First Call, as of May 31, 2024
[5] Source: Consensus Economics Inc., Consensus Forecasts, April 8, 2024, at 3 and 29; estimates for 2030-2034 = (GDP x (1+ CPI))+CPI

This analysis shows important relationships based on 15 years of history, which is a sufficient time-period to draw meaningful conclusions and to frame reasonable expectations for the future. These relationships are as follows:

70 Value Line is the only publication of which we are aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

- Dividends track reasonably well with earnings growth, as would be expected, as earnings drive dividend growth. The average historical dividend growth rate for the three North American proxy groups of 5.56 percent exceeds the average historical earnings growth rate of 4.93 percent by 63 basis points. We conclude that earnings growth is a reasonable proxy for dividend growth, especially with a broad enough company sample.

- Both average earnings and average dividend growth for the three North American proxy groups exceeded actual GDP growth over the period. This is unsurprising, as earnings for utilities can, and do, exceed the growth of the overall economy. As evidenced by the data, there is no fundamental basis to assume that economy-wide GDP growth with a mix of macroeconomic, social and business drivers serves as a limit on utility earnings or dividend growth.

- Looking to the future, it is reasonable to rely on analyst projections, as Concentric and other experts commonly do, even if they exceed GDP growth. In fact, over the historical period, average dividend growth for the three North American proxy groups exceeded historical GDP growth by 97 basis points. Further, the average analyst earnings growth projection of 5.61 percent is reasonably close to the historical earnings growth rate of 4.93 percent.

These relationships indicate that the projected analyst growth rates are entirely reasonable by historical standards. Nevertheless, to address concerns about sole reliance on analysts' earnings growth rates, we relied on a multi-stage specification of the DCF model which trends the earnings growth down to forecast GDP growth. Further, our analysis included other ROE estimation techniques, including the CAPM and Risk Premium model. Those analyses are described below.

3. Multi-Stage DCF Model

In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, we also considered the results of a multi-period (three-stage) DCF model where long-term earnings growth is limited to GDP growth. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional and long-term growth rates. The inherent conservatism of the Multi-stage DCF model is reinforced by the fact that utilities investing in Energy Transition will remain in a capital growth phase for a sustained period that is likely measured in decades.

The multi-stage DCF model transitions from near-term growth (i.e., the average of Value Line, Zacks, S&P Capital IQ Pro, and Thomson First Call forecasts used in the Constant Growth model) for the first stage (years 1-5) to the long-term forecast of nominal GDP growth for the third stage (year 11 and beyond). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows in perpetuity at the same rate as nominal GDP. The following table provides the growth rates in each stage of the analysis for the North American Proxy Group as an example.

Figure 11: Multi-Stage DCF Growth Rates

	Stage 1 (Years 1-5)	Interim Stage (Years 6-10, Average)	Stage 3 (Years 11+)
North American Proxy Group	5.98%	4.99%	3.99%

The return on equity is the internal rate of return based on the current average stock price and this stream of dividend payments. As we have shown above, GDP growth is conservatively low based on the historical earnings and dividend growth of the proxy group companies.

Nominal GDP growth rates were developed using data for each country as reported by Consensus Economics, Inc. for the period from 2030-2034. These forecasts are based on real (constant dollar) growth rates and estimates for inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth are summarized in Figure 12.

Figure 12: Estimates of Nominal GDP Growth[71]

	Canada	U.S.
Real GDP Growth	1.8%	1.8%
Inflation	2.0%	2.2%
Nominal GDP Growth	**3.84%**	**4.04%**

4. DCF Results

The DCF results are summarized in Figure 13 and shown in Exhibits CEA-4 and CEA-5. While we show DCF results for both the Constant Growth and Multi-Stage forms of the DCF model, our ROE recommendation conservatively focuses on the results of the Multi-Stage DCF analysis.

Figure 13: 90-day Average DCF Results[72]

Proxy Group	Constant Growth	Multi-Stage
Canadian	11.06%	10.38%
U.S. Electric	11.30%	9.87%
U.S. Gas	10.34%	9.60%
North American Electric	11.00%	9.83%
North American Gas	10.91%	10.21%
North American Combined	11.09%	9.95%

We place more weight on the results of the North American proxy groups because the companies in those groups are more representative of Ontario's utilities than the Canadian proxy group companies,

71 Consensus Forecasts, for 2030-2034, April 8, 2024, p. 3 (U.S.) and 29 (Canada).
72 Results include an adjustment of 50 basis points for flotation costs and financial flexibility.

as previously discussed, and, therefore, best represent Ontario's utilities from an investment perspective.

F. Capital Asset Pricing Model ("CAPM")

The CAPM is based on the relationship between the required return of a security and the systematic risk of that security. As shown in Equation [4], the CAPM is defined by four components, each of which should represent investors' forward-looking view:

[4] $$Ke = rf + \beta(rm - rf)$$

where:

Ke = the required ROE for a given security;

β = Beta of an individual security;

rf = the risk-free rate of return; and

rm = the required return for the market as a whole.

The term (rm – rf) represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

[5] $$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

re = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [5], is a measure of the variability in the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, beta represents the risk of the security relative to the market.

Each of the variables used in the CAPM are discussed in the subsection below.

1. Risk Free Rate

Bond yields increased sharply in 2022 and 2023 and are generally not expected to return to the very low interest rate environment that prevailed in the decade following the financial crisis of 2007-2009. In general, forecast bond yields, as opposed to the current risk-free rate, best reflect investor expectations and are therefore appropriate for modeling the cost of capital.

The 30-year bond yield is appropriate to estimate the expected equity return for Ontario's utilities as it best matches the risk-free instrument with the lives of utility assets on which the return depends. A 30-year government bond yield forecast is not available from Consensus Economics; therefore, our CAPM analysis relies on the 2025 through 2027 average Consensus Economics forecast of the Canadian 10-year government bond as shown in Figure 14 below and adds the historical spread between 10- and 30-year government debt. This period was chosen to be forward looking, as required for an equity return. We selected a three-year forecast of the Canadian bond yield because it reflects the medium-term outlook for government bond yields as central banks continue to focus on bringing inflation down to target levels. Even with an annual adjustment formula, a forward-looking bond yield is appropriate, as the cost of capital is a forward-looking estimate.

Figure 14: Forecast for 10-Year Government Bond Yields[73]

	2025	2026	2027	Average
Canada	3.10%	3.10%	3.20%	**3.13%**
U.S.	3.80%	3.60%	3.60%	**3.67**%

Although the current spread between 10- and 30-year government bond yields in Canada is negative, the average spread between 10- and 30-year government bond yields over the past 10 years has been approximately 33 basis points in Canada and 47 basis points in the U.S.[74] As illustrated in Figure 15 the projected yields on 30-year government bonds over the period 2025-2027 are 3.46 percent in Canada and 4.14 percent in the U.S. By comparison, the 30-day average of the 30-year bond yields in Canada and the U.S. stood at 3.37 percent and 4.50 percent, respectively, as of June 30, 2024. The

73 Consensus Forecasts by Consensus Economics Inc., Survey Date April 8, 2024, p. 3 and 29.
74 Historical spreads were calculated using daily bond yields published on Bloomberg from June 2015 through May 2024.

projected interest rates we are using in the table below are slightly higher than recent yields in Canada and somewhat lower than recent yields in the U.S.

Figure 15: Risk Free Rate[75]

30-Year Risk Free Yield	**CDN**	**U.S.**
Apr. 2024 Consensus Forecast Average 2025-2027 Forecast 10-Year bond yield	3.13%	3.67%
Average Daily Spread between 10-year and 30-year government bonds (10-year average)	0.33%	0.47%
Average	**3.46%**	**4.14%**

The recent divergence between Canadian and U.S. interest rates has caused some concern among economists focusing on downward pressure on the value of the Canadian dollar. But recent developments indicating lower inflation and easing of central bank policies on both sides of the border have mitigated those concerns. Characterizing these developments, the *Financial Post* reported:

> *Interest rate divergence swept onto the economic radar in the spring as the U.S. economy steamed ahead of its northern counterpart and economists began to forecast that the Bank of Canada would have to cut interest rates many more times than the Fed.*
>
> *Economists worried the resulting chasm between the two benchmark lending rates would bring about dire consequences for the loonie, since lower rates would result in the Canadian currency dropping in value, forcing investors to turn elsewhere for a better return.*
>
> *….*
>
> *Now that inflation is apparently behaving, it could mean a narrower spread between the two central bank rates.*[76]

75 Consensus Economics Inc., Survey Date April 8, 2024; and Bloomberg for daily bond yields. Differences are due to rounding.

76 Posthaste: Economists breathe a bit easier over Canada, U.S. interest rate divergence and outlook for Loonie, *Financial Post*, July 17, 2024.

Concentric views these developments as consistent with the long-term trend of Canadian and U.S. interest rates, and central bank policies, converging.

2. Beta

We have sourced betas for the Canadian and U.S. proxy group companies from both Value Line and Bloomberg. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Bloomberg produces beta estimates based on parameters entered by the user. We have computed Bloomberg betas based on five years of weekly stock returns and using the S&P 500 or the S&P/TSX Composite as the market indexes. Both Value Line and Bloomberg compute adjusted betas to compensate for the tendency of beta to revert toward the market mean of 1.0 over time. The betas used in our CAPM analyses are shown in Figure 16.

Figure 16: Value Line and Bloomberg Betas

Proxy Group	Value Line	Bloomberg
Canadian	0.77	0.85
U.S. Electric	0.95	0.91
U.S. Gas	0.85	0.82
North American Electric	0.92	0.88
North American Gas	0.83	0.87
North American Combined	0.90	0.88

LEI's CAPM analysis relies on raw, unadjusted betas calculated using daily return data for the past five years. LEI then adjusts these betas for differences in financial leverage between Ontario's utilities and the companies in LEI's various proxy groups. We do not agree with LEI's approach to beta, and in particular the use of raw betas, as discussed below in our response to LEI.

There are two primary reasons to adjust raw betas. First, empirical studies have provided evidence that an individual company beta is more likely than not to move toward the market mean of 1.0 over time.[77] Second, adjusting beta serves a statistical purpose. Because betas are statistically estimated and have associated error terms, betas greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Betas below the market average of 1.0 tend to have

[77] Marshall E. Blume, The Journal of Finance, "On the Assessment of Risk," March 1971, Volume 26, No. 1, p. 1-10, and Marshall E. Blume, The Journal of Finance, "Betas and Their Regression Tendencies," June 1975, Volume 30, No. 3, p. 785-795.

negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted betas toward 1.0 to improve forecasts.[78] As current stock prices reflect expected risk, one must use an expected beta to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta. Of note, utility betas have increased since February 2020. This has caused a decrease in the effect of the standard Blume adjustment.

Dr. Blume specifically studied four groups of betas, ranging from a very low beta group (averaging 0.50, and similar to the utility industry) to a very high beta group. Dr. Blume found that his adjustment best predicted future betas for each of the four risk groups over the next seven years. Dr. Blume found that a low beta portfolio that averaged 0.50 migrated towards the grand mean of all betas of 1.0 approximately in accordance with the Blume formula. This study provides empirical evidence that betas migrate towards 1.0 and do indeed exceed their long-term unadjusted averages. Given that the CAPM is intended to estimate the forward-looking cost of capital, it is important to reflect a forward view of beta and its tendency to migrate towards the market mean over time, which is not limited to the long-term historical average of the industry beta.

Dr. Jonathan Lesser was retained by the BCUC to review the methodologies used to estimate the cost of capital as part of the 2021-2022 generic cost of capital proceeding in British Columbia. Dr. Lesser also recognized the merits of using Blume adjusted betas in the CAPM analysis.

> *Because regulators establishing the allowed ROE for a regulated utility are basing that allowed ROE on expected market conditions over an indefinite future, adjusted beta values are typically considered to be more appropriate when applying the CAPM.*[79]

In a follow-up interrogatory on this issue, Dr. Lesser further clarified his position:

> Does Dr. Lesser see merit in adjusting utility betas to anything other than the market value of one? If so, please explain.
>
> Response:

78 Roger A. Morin, *New Regulatory Finance*, p. 74.
79 Regulated Utility Cost of Capital: Theory and Canadian Practice, Jonathan A. Lesser, Continental Economics, Inc., August 4, 2021, p. 42.

> *Dr. Lesser assumes the question is asking about methodologies that adjust raw beta values towards their theoretical long-term values. Dr. Lesser is not aware of beta adjustment methodologies that adjust raw beta values towards a value other than one.*[80]

Dr. Lesser further expanded this position in his response to a clarifying question by the Commission:

> Please confirm, or explain otherwise, if Dr. Lesser endorses the use of the Blume-adjusted Beta for utilities' ROE determination.
>
> Response:
> *I recommend the use of Blume-adjusted beta values. Furthermore, I recommend the use of the beta values reported by Value Line to ensure there is consistency amongst all CAPM estimates.*[81]

We agree with Dr. Lesser, and in Concentric's experience, Value Line and Bloomberg are the most commonly employed sources of beta for cost of capital analysis.

The BCUC noted in its September 2023 Decision and Order that it had not previously accepted the use of Blume adjusted betas. However, the BCUC reversed its previous decisions on this issue, stating:

> *However, the Panel notes Mr. Coyne's explanation that Dr. Blume found that his adjustment was applicable to all betas, ranging from a low of 0.50 to a high of 1.53, and in Mr. Coyne's view, there is no reason to expect that regulated utilities would be an exception to this rule. Given the views of the two experts in this proceeding and since none of the parties object to Mr. Coyne's use of Blume-adjusted data, the Panel accepts the experts' recommendation to use the Blume-adjusted beta estimates for the proxy groups.*[82]

Concentric submitted a full cost of capital analysis in the consultation on Cost of Capital conducted by the OEB in 2009. Concentric's CAPM analysis included the standard Blume adjusted betas from Bloomberg and Value Line, just as we have utilized them in this proceeding. In its decision, the OEB took no issue with Concentric's use of betas with the standard adjustment toward the market mean of 1.0.

80 British Columbia Utilities Commission – Generic Cost of Capital – Project No. 1599176 – BCUC Staff Consultant Response, Dr. Lesser Responses to FortisBC Set 1, November 30, 2021, 10.1.

81 Responses to British Columbia Utilities Commission Information Request No. 2 Generic Cost of Capital Prepared by Jonathan Lesser, Ph.D., June 10, 2022, 7.1.

82 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, p. 75.

3. Market Risk Premium ("MRP")

Estimates of the MRP generally fall into two categories, *ex-post* (historical arithmetic average) and *ex-ante* (forward looking). The historical MRP is based on the arithmetic mean of the equity market returns for large company stocks over the income only return on long-term government bonds, based on data from Kroll (formerly Duff & Phelps). In Canada, the historical MRP is based on return data from 1919-2023, while in the U.S., the historical MRP is calculated using return data from 1926-2023. The forward-looking MRP is calculated by subtracting the risk-free rate for each country from the estimated total return for the overall market, as calculated using the DCF methodology for the S&P/TSX Composite Index in Canada and the S&P 500 Index in the U.S. Exhibits CEA-6.1 and CEA-6.2 show the derivation of the forward-looking MRP for Canada and the U.S.

Because, as noted, the U.S. and Canadian economies are highly integrated and capital flows freely across the border, the risk premiums for each country are highly correlated. Accordingly, it is reasonable to derive a single estimate of the MRP for Canada and the U.S., as provided in Figure 17.

Figure 17: Market Risk Premia – Canada and U.S.

	Canadian	**U.S.**
Actual Historical	5.68%	7.17%
Forward-Looking	12.09%	11.30%
Average	9.06%	

Forward-looking MRPs currently are higher than historical MRPs, reflecting the fact that the historical MRP is based on higher average government bond yields than are available in the current interest rate environment. Noting the substantial difference between the historical and forward market risk premiums, Concentric has relied on the average actual historical MRP for Canada and the U.S. of 6.39 percent in our CAPM analysis. The actual historical MRP may be understated, however, because there is an inverse relationship between interest rates and the MRP, meaning that as interest rates increase (decrease), the MRP decreases (increases). The average 30-year bond yield over the course of the historical periods over which these MRPs were calculated by Kroll was approximately 5.6 percent in Canada and 4.9 percent in the U.S., in contrast to the currently projected 3.5 – 4.1 percent bond yields today. Our use of the actual historical MRP is a conservative (lower) estimate of the market risk premium when interest rates remain below the long-term historical average levels in both Canada and the U.S.

4. CAPM Results

The results of the CAPM analysis, including an adjustment for flotation costs and financial flexibility, are provided in Figure 18 and in Exhibit CEA-7.1, CEA-7.2 and CEA-7.3. Although we have presented our CAPM results using three different MRPs (i.e., an average of the forward-looking and historical MRP, a forward-looking MRP, and an actual historical MRP), as discussed above, our recommended ROE for Ontario's utilities uses the CAPM results with the actual historical MRP.

Figure 18: CAPM ROE Results[83]

Proxy Group	Average MRP	Forward-looking MRP	Historical MRP
Canadian	11.58%	13.80%	9.36%
U.S. Electric	13.07%	15.52%	10.62%
U.S. Gas	12.20%	14.39%	10.00%
North American Electric	12.58%	14.93%	10.23%
North American Gas	12.18%	14.47%	9.89%
North American Combined	12.57%	14.93%	10.22%

In addition, Concentric used the Hamada equation to adjust for differences in financial leverage between the North American proxy group companies (based on their actual capital structure at the operating company level) and the Ontario utilities (based on the current deemed capital structures for each sector). Figure 19 below shows the adjustment to the CAPM results that would be required based on this analysis.

83 Results include an adjustment of 50 basis points for flotation costs and financial flexibility.

Figure 19: Hamada Equation – Adjustment to CAPM Results in Basis Points

Proxy Group	Average MRP	Forward-looking MRP	Historical MRP
Electric T&D (40%)	+194	+251	+138
Electric Generation (45%)	+91	+117	+64
Gas Distribution (38%)	+231	+298	+163

Concentric performed these calculations using the Hamada equation to analyze the effect of financial leverage on returns, but our ROE recommendation is based in part on CAPM results that are not adjusted for such differences in leverage.

G. Flotation Costs and Financing Flexibility

It is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility, with 50 basis points being the norm (as discussed below). The OEB included this adjustment in the 2009 Report; however, LEI is recommending that the authorized ROE for Ontario's utilities should not be adjusted for flotation costs and financial flexibility.

The adjustment for flotation costs compensates the equity holder for the costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for the preparation, filing, underwriting and other costs of issuance of common equity including the costs of financial flexibility such that there is adequate cushion to raise equity in challenging capital market conditions. As the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires. The adjustment also takes into account the need for financial flexibility, meaning that utilities are capital intensive businesses and must be able to access capital markets at all necessary times regardless of conditions in capital markets or the economy. The adjustment is particularly necessary because authorized ROEs in Canada tend to be lower and Canadian utilities are more thinly capitalized than US utilities, as discussed in Section VII of our report.

The practice of allowing a 50 basis point adjustment for flotation costs and financing flexibility is widespread across Canada. As shown in Figure 20, of the ten jurisdictions examined, seven have historically granted the 50 basis point adjustment. Only Quebec deviates from 50 basis points by allowing 30 to 40 basis points, and Manitoba and Saskatchewan, which have only Crown utilities, do not employ regular ROE analyses. In Nova Scotia, the Board's February 2023 order approving a settlement agreement did not specify whether flotation costs were included in the authorized ROE for Nova Scotia Power. The BCUC recently rejected an ROE adjustment for flotation costs and financing flexibility for FortisBC Energy, Inc. and FortisBC Inc. in its September 2023 decision, although it made some adjustment in the equity ratio. In 2016, the BCUC accepted a 50 basis point adjustment for flotation and financing flexibility, but did not accept that the adjustment should automatically be applied to experts' analytical results. The AUC's October 2023 order in the GCOC proceeding for 2024 and beyond included an adjustment of 50 basis points.

Figure 20: Jurisdictional Comparison of Financing and Flexibility Adjustment

Jurisdiction	Adj.	Docket/Proceeding	Notes
Alberta	50 bps	2018 GCOC Decision 22570-D01-2018 and 2024 GCOC Decision 27084-D02-2023	Adjustment of 50 bps is normally included in the allowed return to account for administrative and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.
British Columbia	50 bps	2013 GCOC Decision Stage 1, and 2016 FEI Decision	Has previously approved 50 bps adjustment but cautioned that it should not be considered "automatic" and instead should be considered on a case-by-case basis. (see note above on most recent decision)
Manitoba	N/A	N/A	N/A
New Brunswick	50 bps	2010 EG Decision	Accepted 50 bps as being the lower of two proposed adjustments presented.
Newfoundland and Labrador	50 bps	P.U. 13(2013), and P.U. 18(2018)	Accepted 50 bps adjustment
Nova Scotia	N/A	2023 NSUARB 12	The 2023 Nova Scotia Power rate application was resolved through a settlement agreement that specified an authorized ROE but did not indicate whether that return included flotation costs and/or financing flexibility.
Ontario	50 bps	EB-2009-0084	Base ROE value included a 50 bps adjustment for flotation and financing flexibility.
Prince Edward Island	50 bps	Order UE19-08	Approved ROE included a 50 bps adjustment for flotation costs.
Saskatchewan	N/A	N/A	N/A
Quebec	30-40 bps	D-2011-182/R-3752-2011	Regie determined provision for flotation costs and other costs of accessing capital markets ranging from 30-40 bps, with a greater weighting at the lower end of the range.

For the above reasons, Concentric has adjusted the results of our DCF and CAPM analyses by 50 basis points for flotation costs and financing flexibility.

H. Risk Premium Analysis

In general terms, the Risk Premium approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The Risk Premium approach estimates the ROE as the sum of the equity risk premium and the yield on a particular class of bonds.

$$ROE = RP + Y \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield) and

Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the ROE and others that consider historical, or ex-post, estimates. For our Risk Premium analyses, we have relied on authorized returns from a large sample of U.S. electric utilities and U.S. gas distribution companies. In addition, we have conducted a Risk Premium analysis based on authorized returns for Canadian electric and gas utility companies since 2000.

To estimate the relationship between risk premia and interest rates, we conducted a regression analysis using the following equation:

$$RP = a + (b \times Y) \quad [7]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the 30-Year Treasury Yield);

a = Intercept term;

b = Slope term; and

Y = 30-Year Treasury Yield.

Data regarding allowed ROEs were derived from over 900 electric utility company rate cases and over 750 gas distribution utility rate cases in the U.S. from January 1992 through May 31, 2024, as reported by Regulatory Research Associates.

Figure 21: Risk Premium Results – U.S. Electric

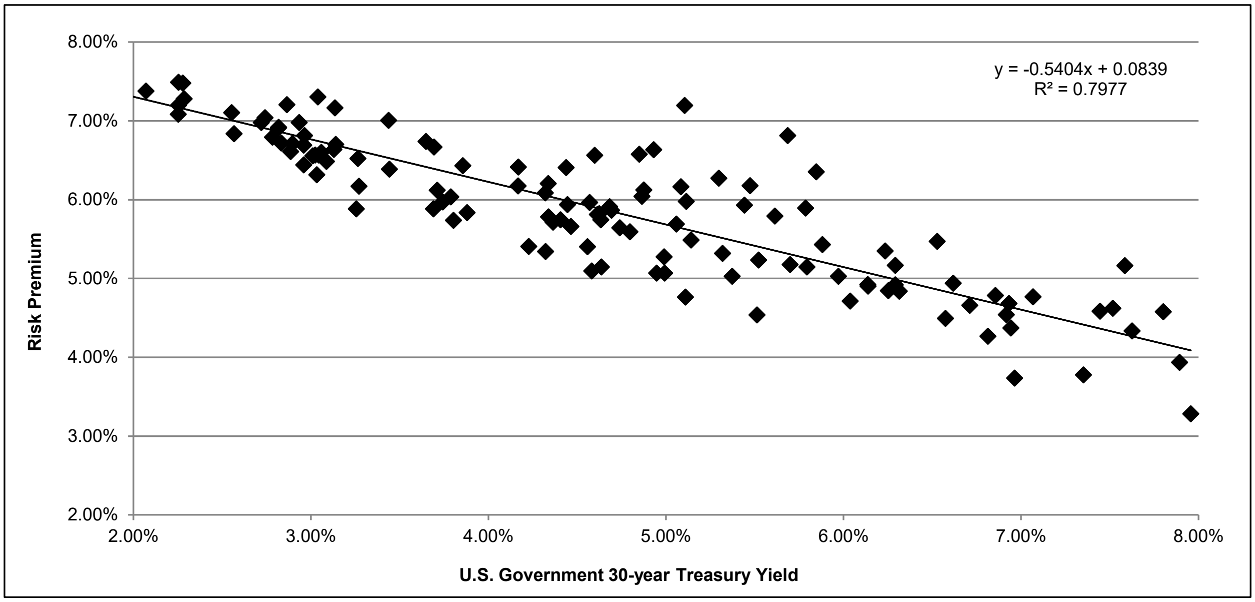
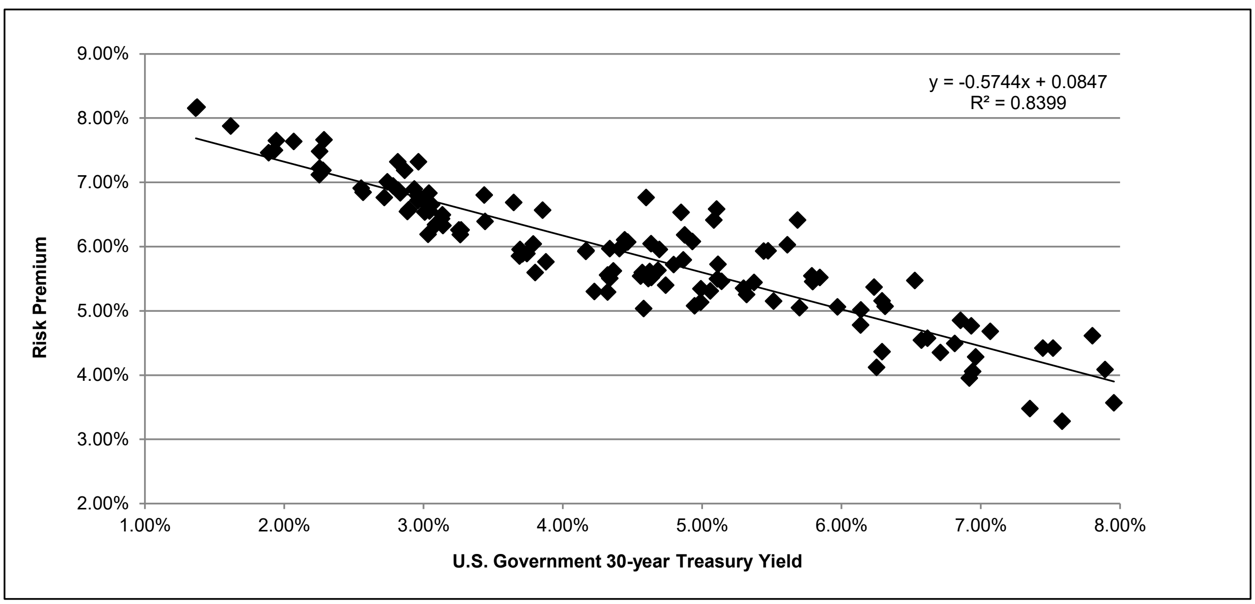


Figure 22: Risk Premium Results – U.S. Gas



As illustrated by Figure 2323 and Figure 24, the risk premium varies with the level of the bond yield, and generally increases as the bond yields decrease, and vice versa. In order to apply this relationship to current and expected bond yields, we consider three estimates of the 30-year U.S. Treasury yield: the current 30-day average, a near-term Blue Chip consensus forecast for Q3 2024 – Q3 2025, and a long-term Blue Chip consensus forecast for 2025–2029. We find this five-year result to be most applicable because investors typically have a multi-year view of their required returns on equity. Based on the regression coefficients in Exhibits CEA-8.1 and 8.2, which enable the estimation of the risk premium at varying bond yields, the results of our Risk Premium analysis are shown in Figure 23 and Figure 24.

Figure 23: Risk Premium Results – U.S. Electric

	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Q3 2024–Q3 2025 Forecast for Yield on 30-Year Treasury Bond[84]	Using 2025-2029 Forecast for Yield 30-Year Treasury Bond[85]
Yield	4.66%	4.40%	4.30%
Risk Premium	5.87%	6.01%	6.06%
Resulting ROE	10.53%	10.41%	10.36%

84 Blue Chip Financial Forecasts, Vol. 43, No. 5, May 1, 2024, at 2. We typically prefer to use Blue Chip as our source for interest rates forecasts in the U.S. However, Blue Chip does not provide a long-term forecast for Canada, so the risk-free rate in our CAPM analysis uses bond yields from Consensus Economics.

85 Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, p. 14.

Figure 24: Risk Premium Results – U.S. Gas

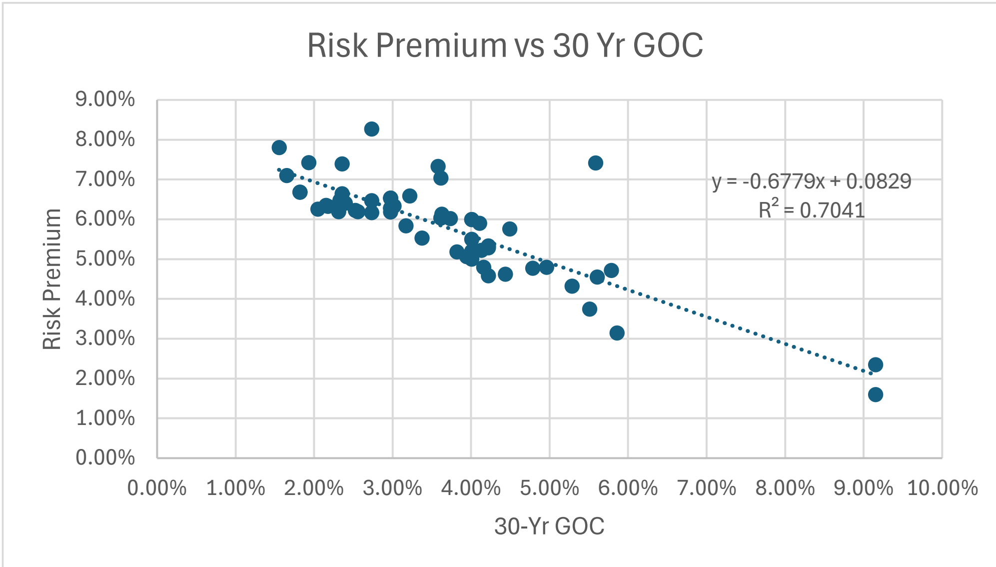
	Using 30-Day Average Yield on 30-Year Treasury Bond	Using Q3 2024–Q3 2025 Forecast for Yield on 30-Year Treasury Bond[86]	Using 2025-2029 Forecast for Yield 30-Year Treasury Bond[87]
Yield	4.66%	4.40%	4.30%
Risk Premium	5.79%	5.94%	6.00%
Resulting ROE	10.45%	10.34%	10.30%

We also conducted a risk premium analysis based on approximately 60 Canadian decisions for electric and gas utilities from 1994 through 2023. As in the U.S., the regression analysis for Canada shows an inverse relationship between interest rates and the equity risk premium. Figure 25 shows the regression equation produced by this analysis. See also Exhibit CEA-9 for the full risk premium analysis for Canada.

86 Blue Chip Financial Forecasts, Vol. 43, No. 5, May 1, 2024, p. 2. We typically prefer to use Blue Chip as our source for interest rates forecasts in the U.S. However, Blue Chip does not provide a long-term forecast for Canada, so the risk-free rate in our CAPM analysis uses bond yields from Consensus Economics.

87 Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, p. 14.

Figure 25: Risk Premium Results - Canada[88]



The Canadian risk premium analysis shows that the average equity risk premium in Canada since 1994 has been 5.94 percent. By comparison, this represents a relatively modest increase from the risk premium determined by the OEB in the 2009 consultation of 5.5 percent.89 The results of the Canadian risk premium analysis, shown in Figure 26 below, support the reasonableness of our DCF and CAPM analyses for the North American proxy group companies.

88 The two ROE decisions shown on the far-right side of the chart are from 1994, when interest rates were significantly higher than they are today, and the resulting equity risk premium was significantly lower.

89 OEB Cost of Capital Report, 2009, p. 37.

Figure 26: Risk Premium Results - Canada

	Using 30-Day Average Yield on 30-Year GOC Bond[90]	Using 2025–2026 Forecast for Yield on 30-Year GOC Bond[91]	Using 2025-2029 Forecast for Yield 30-Year GOC Bond[92]
Yield	3.55%	3.46%	3.55%
Risk Premium	5.89%	5.95%	5.89%
Resulting ROE	9.44%	9.41%	9.44%

I. Comparison to Other Authorized ROEs

As shown in Figure 27 the authorized ROE for Canadian investor-owned electric utility companies currently ranges from 8.50 percent (Newfoundland Power) to 9.65 percent (FortisBC Inc.), with an average of 9.16 percent. The authorized ROE for Canadian investor-owned gas distribution companies currently ranges from 8.90 percent (Energir) to 10.65 percent (Eastward Energy), with an average of 9.23 percent. The average authorized return for electric utilities in the U.S. is 9.67 percent since January 2023 and the average for U.S. gas distributors is 9.65 percent.

90 Bloomberg Professional, as of May 31, 2024.
91 Consensus Economics, April 2024, p. 29. We used the same forecast of government bond yields as in our CAPM analysis. See Figure 15 of this report.
92 Consensus Economics, April 2024, p. 29.

Figure 27: Comparison of Northern American Authorized Equity Returns

Operating Utility	ROE	Equity Ratio
Ontario (current)	**9.21%**	**38.0% - 45.0%**
Alberta Electric utilities[93]	9.28%	37.0%
FortisBC Inc.	9.65%	41.0%
Maritime Electric	9.35%	40.0%
Newfoundland Power	8.50%	45.0%
Nova Scotia Power	9.00%	40.0%
Canadian Electric Avg	**9.16%**	**40.6%**
Canadian Electric Median	**9.28%**	**40.0%**
U.S. Electric Mean[94]	**9.67%**	**50.2%**
Apex Utilities	9.28%	39.0%
ATCO Gas	9.28%	37.0%
Energir, Inc.[95]	8.90%	38.5%
FortisBC Energy Inc.	9.65%	45.0%
Gazifere	9.05%	40.0%
Canadian Gas Avg	**9.23%**	**39.9%[96]**
Canadian Gas Median	**9.28%**	**39.0%**
U.S. Gas Mean[97]	**9.65%**	**52.1%**

As discussed in Section VI of our report, the Ontario utilities have significantly greater financial risk than many other electric and gas distribution companies, especially those in the U.S. In particular, the Ontario utilities have a more highly leveraged regulatory capital structure, which contains 40 percent common equity for electric distributors and transmitters, 38 percent for Enbridge Gas and 45 percent for OPG. These equity ratios are low by comparison to the U.S. companies in the North American proxy groups. In addition to resetting the ROE as proposed, if the OEB does not increase the deemed equity ratios of Ontario's electric and gas utilities, as we recommend, then it is

93 Alberta Electric utilities includes ATCO Electric, Fortis Alberta, ENMAX, and EPCOR.
94 Source: Regulatory Research Associates, decisions from January 1, 2023, through May 31, 2024.
95 Deemed capital structure for Energir, Inc. includes 6.5 percent preferred equity, so that debt ratio is 55 percent.
96 The OEB Decision and Order for Enbridge Gas in EB-2022-0200 dated December 21, 2023, stated on page 66 that Enbridge Gas's reply argument documented that the customer weighted average equity ratio used by LEI for the Canadian peer group would increase to 40.5% when updated to include the 45% deemed equity ratio for FEI approved by the BCUC in September 2023. Concentric has used a simple average in this table.
97 Ibid.

appropriate for the Board to approve a further increase in the ROE in order to compensate equity investors for the greater financial risk of the Ontario utilities. Otherwise, Ontario's electric and gas utilities are placed at a disadvantage in competing for capital with other companies of comparable risk.

For example, in September 2023, the BCUC issued a decision in the generic cost of capital proceeding for FortisBC Energy Inc. (FEI, a gas utility) and FortisBC Inc. (FBC, an electric utility) in which the authorized ROE was increased to 9.65 percent for both FEI and FBC, while the deemed equity ratio for FEI was raised from 38.5 percent to 45.0 percent and for FBC from 40.0 percent to 41.0 percent. FEI and FBC both operate under performance-based regulation ("PBR") plans with a four-year term, similar to most utilities in Ontario. The PBR plans for FEI and FBC include numerous deferral and variance accounts and regulatory mechanisms that reduce regulatory lag and facilitate timely recovery of operating and capital costs, much like the Custom IR plans in Ontario. FEI has a quarterly gas cost mechanism that adjusts rates for the variance between forecast and actual purchased gas costs. Given the similarities between FEI and FBC and the Ontario utilities from a business risk perspective, the maintenance of the current (or a lower) ROE and equity ratios (i.e., an authorized return of 9.21 percent on 38.0 or 40.0 percent deemed common equity) would fail to meet the comparable return standard given FEI's authorized ROE of 9.65 percent on 45.0 percent deemed common equity and FBC's authorized ROE of 9.65 percent on a 41.0 percent equity ratio. As discussed earlier, Ontario utilities are competing for capital with other North American utilities, and this competition will become even more accentuated in the Energy Transition, as utilities vie for limited investor capital.

LEI's Recommendation and Concentric's Response

LEI recommends resetting the base ROE in the OEB formula to 8.95 percent within a range from 8.23 percent to 10.22 percent, as discussed on pages 125-127 of LEI's report. LEI's recommendation is based solely on the results of its CAPM analysis and does not include an adjustment for flotation costs or financing flexibility, as explained on page 122 of LEI's report. LEI recommends considering the transaction costs associated with equity issuances as operating costs. As shown in Figure 41 of LEI's report, their CAPM analysis uses a risk-free rate of 3.19 percent, an average beta coefficient of 0.69, and a market risk premium ranging from 7.28 percent to 10.16 percent based on historical U.S. return data. LEI considers six alternative methods for setting the base ROE for Ontario's utilities, including Alternative #6, which takes an average of the DCF, CAPM and Risk Premium results, but LEI ultimately determines that sole reliance on the CAPM is appropriate.

Concentric disagrees with the following aspects of LEI's analysis to set the base ROE: 1) primary reliance on a single model to estimate the authorized ROE rather than multiple methodologies; 2) certain inputs to the CAPM analysis, including LEI's use of raw betas rather than Blume adjusted betas and the level of the market risk premium; 3) LEI's concerns with the DCF model to estimate the cost of equity for regulated utilities; and 4) the exclusion of an adjustment for flotation costs and financing flexibility, which is a departure from the OEB's past practice of allowing an adjustment of 50 basis points

With regard to LEI's reliance on the CAPM analysis to re-set the base ROE in the formula, Concentric's view is that the use of multiple methodologies to estimate the cost of equity is the preferred approach, both from the standpoint of financial principles and regulatory precedent in other jurisdictions. We elaborate on the financial principles previously in this report, and Figure 45 of LEI's report demonstrates that most North American jurisdictions rely on multiple models to establish the authorized ROE. Although LEI shows in Figure 45 that the AUC relies on an Equity Risk Premium approach, the base ROE in the new Alberta formula was based on the average results of the CAPM and DCF models. If LEI had based its ROE recommendation on Alternative #6, which uses multiple methodologies, the authorized ROE for Ontario's utilities would be 9.46 percent, as shown in Figure 46 of LEI's report.

In response to the specific inputs LEI has employed in its CAPM analysis, the risk-free rate in Concentric's analysis is based on the forecast 10-year government bond yields for Canada and the U.S. from Consensus Economics for the period from 2025-2027 plus the average spread between 10 and 30 year government bonds. LEI, on the other hand, has used an average forecast of the 30 year Government of Canada bond yield from six major Canadian banks for the four quarters of 2025. Although Concentric has used a different method and source for the risk-free rate in our CAPM analysis, we do not specifically object to LEI's use of a 30-year government bond forecast in the CAPM and we have adopted that approach for the Long Canada Bond Forecast as discussed in the next section of our Report.

With regard to beta, Concentric believes it is appropriate and consistent with empirical financial research to use Blume adjusted betas rather than raw betas for the reasons discussed earlier in our Report. In addition, Concentric's CAPM analysis uses weekly betas from Value Line and Bloomberg, which are based on five years of market return data, while LEI has calculated daily betas for the companies in its three proxy groups. LEI then adjusts these raw betas for differences in financial leverage between the proxy group companies and Ontario's electric and gas utilities. Concentric has performed a similar calculation using the Hamada equation, although we have not relied on that version of our CAPM analysis in our ROE recommendation. If LEI had used Blume adjusted betas calculated weekly over five years in Figure 39 of its report, the weighted average beta for the companies in LEI's three proxy groups (as shown in Figure 40 of LEI's report) would be 0.827, and the average CAPM result (as shown in Figure 41 of LEI's report) would be 10.07 percent, not including an adjustment for flotation costs and financial flexibility.

LEI uses a market risk premium ranging from 7.28 percent to 10.16 percent based on U.S. historical return data for the most recent 10-, 20- and 30-year periods. Concentric's CAPM analysis relies on an average Canadian and U.S. historical market risk premiums of 6.39 percent, based on Kroll data going back to 1926 in the U.S. and 1919 in Canada. The differences are that LEI has only relied on U.S. return data while Concentric has averaged Canadian and U.S. return data, and LEI has used shorter time periods to compute the MRP while Concentric has conservatively relied on the entire historical dataset.

LEI states on page 51 of its report that, "Discounted Cash Flow (DCF) valuation is the most fundamental approach to valuing a firm," yet LEI does not utilize the DCF model when establishing its base ROE recommendation in Ontario. LEI expresses concerns with the DCF model for purposes of estimating the authorized ROE for Ontario's utilities. In particular, LEI comments that the projected earnings growth rates from equity analysts tend to be overly optimistic, causing the results of the DCF model to be overstated. As discussed previously in our Report, Concentric does not share this concern with analyst growth rates being too optimistic for the companies in our proxy groups, as shown in Figure 10 of our Report. Nevertheless, Concentric has conservatively relied on the Multi-Stage DCF model rather than the Constant Growth DCF model, thereby moderating the effect of near-term EPS growth rate projections in years 1-5 with long-term projected GDP growth for Canada and the U.S. in years 11-200. We believe this adequately addresses any concerns the Board may have with optimism bias in short-term EPS growth rates.

Lastly, Concentric has included an adjustment of 50 basis points to the results of our DCF and CAPM results for flotation costs and financial flexibility, consistent with prior precedent in Ontario as well as most other Canadian jurisdictions. LEI has not included an adjustment for flotation costs and financial flexibility, however, arguing that such costs should be recovered as operating expenses if they are incurred during a rate year. LEI's recommendation is inconsistent with Canadian regulatory precedent on this issue and fails to recognize the need for regulated utilities to have sufficient financial flexibility to raise capital under a variety of capital market conditions. This is particularly important given the significant capital investments that will be required in response to the Energy Transition. Further, as discussed previously, LEI's approach puts Ontario utilities at risk of not recovering these costs simply because they were not incurred in the test year or are expected to be incurred over the rate plan. LEI's approach, therefore, would appear to go against LEI's principles of "transitioning away from the status quo only if the associated benefits are material," and "fairness in approach to consumers and utilities."

If the OEB were to continue to include an adjustment for flotation costs and financing flexibility, LEI's CAPM results would increase to 9.45 percent and the results of Alternative #6 (the average of the CAPM, DCF, and ERP models) would increase to 9.79 percent,[1] which is within 21 basis points of our ROE recommendation of 10.0 percent. (*LEI Report, p. 126)*

VI. THE ONTARIO ROE FORMULA

A. Introduction and Summary

Based on our analysis, we conclude that the existing methodology (i.e., the current OEB formula) has generally produced a return on equity that is consistent with returns for electric and gas utilities elsewhere in Canada. The ROE produced by the formula, however, is substantially lower than authorized returns for comparable risk electric and gas utilities in the U.S. and lower than the results of traditional models used to estimate ROE such as the DCF and CAPM. Figure 28 and Figure 29 below compare the returns produced by the Ontario formula to returns for other Canadian and U.S. electric and gas utilities from 2009-2024 YTD.

Figure 28: Ontario Formula vs Canadian and U.S. Electric Authorized ROEs

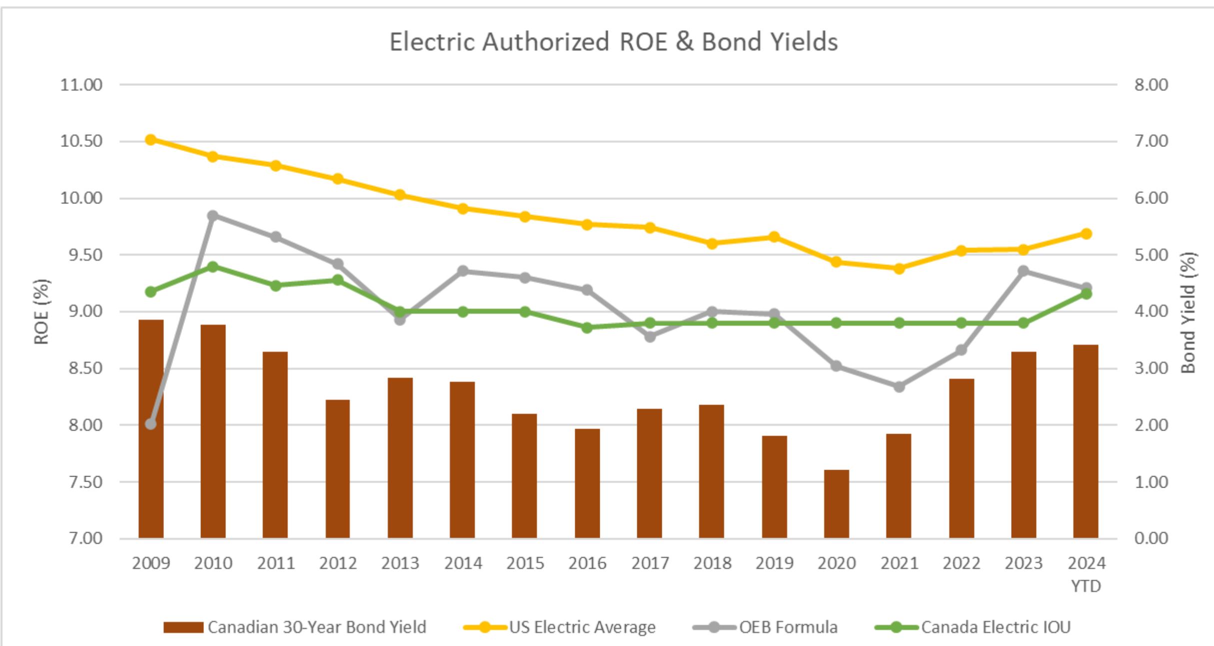
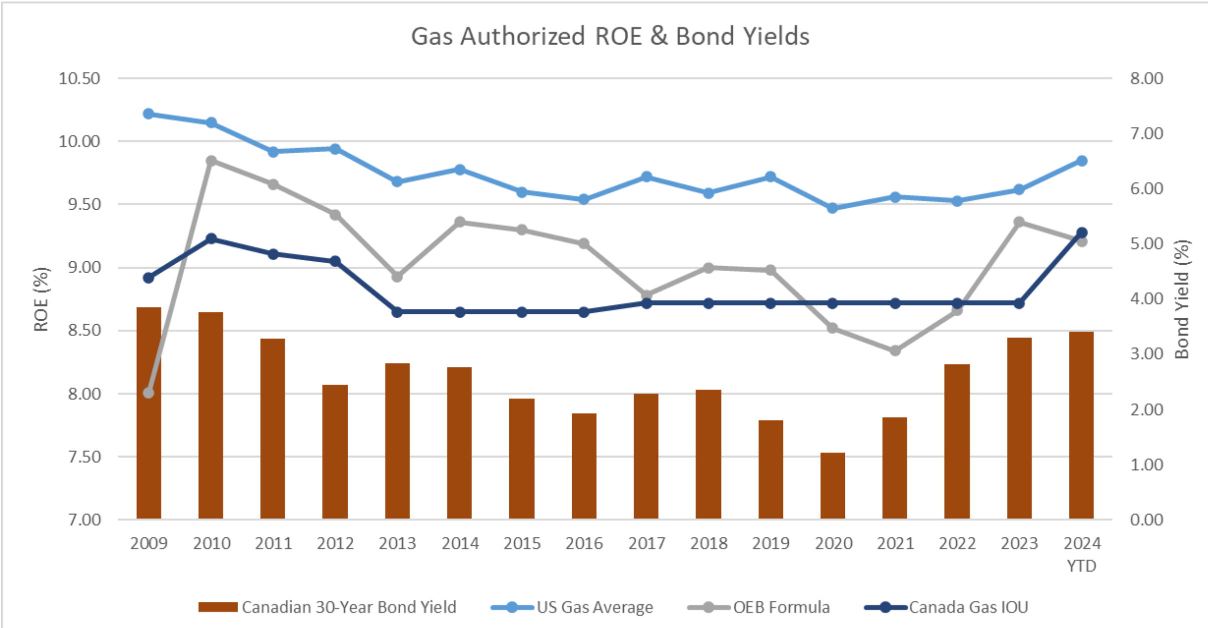


Figure 29: Ontario Formula vs Canadian and U.S. Gas Authorized ROEs



In Concentric's view, the current formula return of 9.21 percent in Ontario has diverged from what is considered a fair return for comparable risk companies. To correct this divergence, we recommend that the Board start by re-setting the base ROE to reflect current market conditions.

As to what has caused this divergence in the OEB formula since it was last modified in 2009, our view is that a fair return depends on more than just changes in government bond yields and utility credit spreads. While those are important factors in determining equity costs for utilities, there are other key elements that are not captured by the OEB formula. For example, betas have increased substantially for electric and gas utilities since January 2020. This indicates that regulated utilities are no longer perceived by investors as having well below average market risk. Utility betas have been in the range of 0.80 to 0.90 percent since early 2020, as compared to the historical average level of 0.60 to 0.70 in the preceding 10 years, notwithstanding the increase observed in 2009 in the wake of the Great Recession. This shift in utility risk is not reflected in the Ontario formula, which highlights the importance of periodic reviews of the formula to ensure that it continues to produce a fair return.

OEB Staff issued a report in January 2016 which found that the formula had performed well since it was modified by the Board in the 2009 Report. The OEB formula has not been reviewed since then, even though the original intention of the Board in the 2009 Report was to revisit the formula approximately every five years.

Another important consideration is how the OEB formula return compares to authorized ROEs for other regulated utilities in Canada and the U.S. Concentric's analysis demonstrates that the OEB formula has produced a comparable return for Ontario's electric and gas utilities to the average equity return for Canadian electric and gas utilities in most years since the formula was modified in 2009. The exception is during periods of very low interest rates in 2020-2022 when the COVID-19 pandemic caused central banks in Canada and around the globe to reduce short-term interest rates to near zero and to engage in purchases of government and corporate bonds in order to support the stability of financial markets and stimulate the economy. Because the OEB formula is tied to bond yields, the formula return declined during these years even though the risk premium for equity investors increased substantially. Under the OEB's rate plans, utilities are typically locked-in to the formula rate determined in the year of rebasing, so an unfair return can endure for up to five years.

The returns produced by the OEB formula are substantially lower than those for U.S. companies of comparable risk. This is important because Ontario's utilities must compete with other Canadian and U.S. companies to attract capital. Market data indicate that the cost of capital has increased for all North American utilities, including those in Ontario since the Board last examined this issue.

Concentric recommends that certain parameters of the Ontario ERP-based formula be modified to ensure that the formula provides a fair return for regulated utilities when government bond yields disconnect from equity investors' return requirements. This occurs infrequently, but history has shown over the past 15 years that when it does occur, the OEB formula tends to produce a return that is lower than what the ROE estimates would be using traditional financial models such as the DCF and CAPM. For example, the OEB formula return of 8.34 percent in 2021 was well below the average authorized ROE for other Canadian and U.S. utilities. In addition, it is very important that the Board periodically review the formula return because the cost of equity depends on factors other than government bond yields and utility credit spreads.

The following section of our report explains in more detail our recommendations.

B. Benefits and Challenges of an ROE Formula

The primary benefits of a formulaic approach to ROE are the administrative efficiencies gained through avoidance of litigated proceedings, and the predictability and transparency associated with the process. In Concentric's view, the application of a formula by the OEB is generally perceived as favorable by credit rating agencies and equity investors because the return is set in a transparent and predictable manner and provides for relatively more stable cash flows and earnings for Ontario's regulated utilities.

Given these potential benefits, one would expect the widespread adoption of a formulaic approach. There are, however, several challenges associated with the successful implementation of ROE formulas, including: 1) ability of the formula to produce returns that meet the Fair Return Standard under a variety of economic and capital market conditions and across all individual regulated utilities; 2) all formulas rely on imperfect proxies for equity costs based on historical relationships that shift over time and are challenged to capture the complex factors that determine an investor's required return; 3) ROE formulas in Canada have been dependent on the level of government bond yields and, as a result, do not fully reflect market uncertainty caused by macroeconomic developments and central bank responses and the cost of equity for the utility sector; and 4) the Fair Return Standard requires analysis, market information, and judgment in its implementation, and a formula inevitably limits the regulator's ability to weigh the many factors that enter into the determination of the cost of equity.

The advantages of non-formulaic approaches include adaptability to changing market conditions, periodic input from stakeholders greater flexibility to respond to utility-specific risks, and the ability of the regulatory commission to act on updated capital market information. Generally, utility ROEs are not volatile over time, and periodic rate hearings provide a sufficient response to changing market conditions while retaining relative stability and predictability in returns.

C. Resetting the Base ROE Used in Formula

Great care must be exercised in establishing the base ROE, as the effects of any understatements or overstatements will be felt with each succeeding application of the formula. Concentric is of the view that the base ROE should be set in accordance with traditional ROE setting methodologies utilizing multiple approaches based on a proxy group of companies with similar risk profiles in a process where the regulator hears evidence from regulated utilities and stakeholders. Most jurisdictions go through this process each time the ROE is set. A fully litigated regulatory process where stakeholder evidence is presented and heard by the regulator generally provides a sound basis for a fair determination of ROE. It is also important that interrelated base parameters are set in the initial formula to recognize the relationship between them (e.g., the base level of credit spread corresponds to the base level of bond yields). Concentric recognizes that the average parameter values incorporated in a formula such as that used by the OEB will inevitably fail to capture the dynamic nature of capital markets and changes in industry risk (e.g., the Energy Transition) over time. It is therefore essential as a tradeoff for regulatory efficiency achieved by a formula to review the results in a comprehensive manner on a regular basis, as we have recommended.

Our evidence demonstrates that there have been increases to the cost of equity and the business and financial risk of Ontario's regulated utilities since the OEB's 2009 Report as a result of changes in capital markets and the fundamental shift brought to the industry by the Energy Transition. Consequently, it is essential for the OEB to reset the base ROE and the deemed equity ratios for Ontario's electric and gas utilities to meet the Fair Return Standard. This is an important prerequisite to establishing a formula that produces ROEs that consistently meet the Fair Return Standard in 2025 and beyond. Based on our analysis as discussed previously, the authorized ROE should be rebased at 10.0 percent.

D. Risk Premia

As previously recognized by the Board through the use of a higher equity ratio, OPG faces a different and greater level of risk compared to distributors and transmitters. As such, the base ROE recommendation of 10.0 percent understates the ROE needed to meet the Fair Return Standard for OPG. There are also no direct comparators in the proxy groups analyzed by Concentric for OPG's pure-play rate-regulated generation operations. As such, Concentric recommends that should OPG provide a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied to set its authorized ROE, the OEB considers that proposal at its discretion as part of that proceeding.[98]

E. Design of ROE Formula

Most ROE formulas are updated annually, without special proceedings. However, the approach to automatically adjust equity returns must be balanced against the need to periodically benchmark the formula return against traditional measures of required returns for regulated utilities to ensure that the formula result remains fair and reasonable. A functional ROE formula must be able to approximate the results produced in a rate-setting hearing process.

Any selected formulaic approach should consider the following criteria:

- Tracks required utility equity returns and capital market conditions;
- Ease of administration;
- Based on commercially accessible inputs;
- Promotes regulatory transparency;
- Forward-looking for the applicable rate period;

98 Consistent with the OEB's finding in EB-2009-0084 Report of the Board, p. 13.

- Reasonable degree of stability; and
- Specified timetable for periodic review and/or rebasing of the formula

F. Ontario Formula Parameters

The current OEB formula is expressed as:

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

And it was implemented with the following starting values:

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

As shown above, the current formula is based on an ROE of 9.75 percent, a 10-year bond yield forecast of 4.25 percent, the average spread between 10- and 30-year government bond yields, and a utility credit spread of 1.415 percent. Each year the OEB compares the current bond yield forecast and utility credit spread in September against the historical parameters and adjusts the authorized ROE accordingly. Figure 30 summarizes the OEB's formula parameters from 2010-2024.

Figure 30: OEB ROE Formula Parameters

	Formula ROE	10 yr forecast	10/30 spread	Util spread
Base	9.75%	4.25%		1.415%
2010	9.85%	3.90%	0.564%	1.406%
2011	9.58%	3.50%	0.430%	1.392%
2012	9.12%	2.35%	0.581%	1.479%
2013	8.98%	2.15%	0.569%	1.403%
2014	9.36%	2.90%	0.496%	1.483%
2015	9.30%	2.85%	0.530%	1.386%
2016	9.19%	1.95%	0.756%	1.831%
2017	8.78%	1.40%	0.637%	1.680%
2018	9.00%	2.40%	0.362%	1.395%
2019	8.98%	2.70%	0.013%	1.416%
2020	8.52%	1.50%	0.196%	1.516%
2021	8.34%	0.85%	0.523%	1.477%
2022	8.66%	1.60%	0.540%	1.350%
2023	9.36%	3.30%	-0.070%	1.653%
2024	9.21%	3.25%	-0.196%	1.525%
Average	9.08%	2.44%	0.395%	1.493%
STDEV	0.40%	0.87%	0.28%	0.13%
CV	4.40%	35.71%	70.94%	8.96%

The OEB examined its formulaic approach to setting ROEs in 2016, and OEB Staff published its report on January 14, 2016. OEB Staff reviewed the actual results achieved by Ontario's rate-regulated utilities and conducted a jurisdictional review of approaches to the cost of capital followed by other regulators in Canada, the U.S., the United Kingdom and Australia. OEB Staff concluded at that time that the OEB's cost of capital policy had worked as intended, that movement in the parameters had followed macroeconomic trends and activity, and that the approach had not resulted in excessive or anomalous volatility.[99]

The Ontario formula, however, began to produce returns that deviated from authorized returns elsewhere in Canada and the U.S. as yields on Canadian government bonds declined to historically low levels in 2020-2021. Because the Ontario formula is tied solely to changes in government bond yields and utility credit spreads, it did not reflect the uncertainty and volatility in capital markets that impacted equity investors more than debt investors. For example, the OEB's formula return in 2020 was 8.52 percent (or 20 basis points below the average authorized ROE for electric distribution companies in Canada) and 8.34 percent in 2021 (the lowest authorized ROE in Canada and 36 basis points lower than the average for electric distributors in Canada). As previously noted, these returns can last in rate plans for up to five years. The OEB's formula return in most years from 2010 through 2019 was in the range of 20 to 50 basis points higher than the average authorized ROE for electric distribution companies in Canada.

The figure above shows that the 10-year bond currently has a higher yield than the 30-year bond, which is known as an inversion of the yield curve. The figure above also includes the coefficient of variation ("CV") for each column of data. The CV is a relative measure of variability. As shown in the figure above, the spread between 10- and 30-year government bonds has the highest CV among the OEB's parameters, at 70.94 percent. Because of its high CV, there is some question as to whether the formula is providing a reasonable return to equity investors during years in which the 10/30 spread deviates significantly from the long-term average of around 0.40 percent. It is not sustainable for short-term bonds to have higher yields than long-term bonds. The use of a long-term average yield spread in such years could help to smooth out short-term aberrations that are not representative of capital costs over the long-term. Alternatively, the OEB could consider other sources that provide a forecast of the 30-year government bond yield, as LEI has recommended.

99 OEB Staff Report, EB-2009-0084, January 14, 2016, p. 1.

Another concern is that the 10-year government bond forecast fell below 2.0 percent from 2020-2022, due to the extraordinary policy accommodation of central banks in Canada and around the world in response to the COVID-19 pandemic, which in turn drove down interest rates on government debt. Although bond yields were near historically low levels, the risk for equity investors increased substantially as shown by extreme market volatility and higher risk premiums.

Further, the utility credit spread over government bond yields has the lowest CV of the parameters from 2010-2023 and provides an indicator of utility risk from the perspective of a debt investor that serves as a proxy for changes in utility equity risk. This was an important modification to the OEB formula in the 2009 proceeding and has helped to improve the performance of the adjustment mechanism in terms of its ability to track returns for comparable utilities in other Canadian jurisdictions.

G. Risk-Free Rate – Base LCBF

The Ontario formula uses a 10-year bond yield forecast published by Consensus Economics in September of each year. The base LCBF is based on an average of the 3-month and 12-month forecast yield on the 10-year government of Canada bond. Consensus Economics does not publish a forecast for the 30-year Long Canada Bond Yield. Therefore, the average spread between 10- and 30-year government bond yields during the month of September is added to the 10-year bond yield forecast. This is a potential area of concern due to the ongoing inversion of the 10/30 yield spread (discussed above). The 10/30 spread has been negative since April 2022 as the Bank of Canada has engaged in more restrictive monetary policy, causing short-term bond yields to exceed longer term bond yields. This relationship is not normal (long-term bond yields are typically higher than short-term yields), and the inversion has caused the OEB formula ROE to decline in certain years even as longer-term interest rates increased substantially. As discussed above, the 10/30 spread has the highest CV of any formula parameter, indicating the greatest amount of relative variability, and therefore the use of the spread from only one month can lead to counterintuitive results.

There are several possible ways to address this shortcoming. The first is to use the long-term average spread between 10- and 30- year government bonds whenever the 10/30 yield spread is inverted. Over the long term, the average yield spread has been approximately 40 basis points in Canada. Concentric's view is that it is not reasonable to use a negative spread in the ROE formula because that is not the normal relationship between 10- and 30-year bonds. The second approach is to use a 30-year bond yield forecast, which is the method recently adopted by the AUC in October 2023 and that was recommended by LEI in this proceeding. The base LCBF in the new AUC formula is based on an average of the forecast of the quarterly 30-year GOC bond yield for each of the four quarters in the coming year from three Canadian investment banks – RBC, TD Bank, and Scotia Bank – which receives a 75% weight, and the current 90-day average 30-year GOC bond yield, which receives a 25% weight. Concentric prefers this latter approach. Based on the most recent information available as of May 31, 2024, using the Alberta methodology, the LCBF would be set at 3.36 percent. If the OEB adopts this recommendation, we suggest updating these data closer to when a final decision is made in this proceeding.

H. Long Canada Bond Yield Adjustment Factor

The OEB formula uses an Adjustment Factor for the LCBF to estimate the relationship between changes in the utility cost of equity and changes in the LCBF. Currently, the LCBF Adjustment Factor is set at 0.50, implying that for every 100 bps increase (or decrease) in the LCBF, it is reasonable to expect a 50 bps increase (or decrease) in the utility cost of equity. Accordingly, the OEB formula incorporates this relationship by adding 0.50 times the change in LCBF, relative to the base LCBF, to the base ROE.

Although the positive correlation between the utility cost of equity and LCBF has been historically well-noted, the strength of the relationship has weakened over time. This may be attributable to a partial decoupling of the relationship as bond yields were driven increasingly lower by central bank policy, increased reliance on multi-model approaches by experts and regulators, and policies of "gradualism" adopted by regulators in response to market volatility. To reflect these trends, Concentric has estimated an updated relationship between the cost of equity and long bonds and recommends lowering the Adjustment Factor for the LCBF from 0.50 to 0.40, based on a multivariate regression analysis covered in more detail below, in subsection J.

I. Base Utility Credit Spread

The utility bond spread was the main improvement to the Ontario formula in 2009 after the OEB became concerned that the formula was not providing a fair return during a period of very low government bond yields during and after the financial crisis of 2008/09. Because government bond yields do not reflect the industry risk of regulated utilities, it is beneficial to include the spread between government and utility bonds. Indeed, the California Public Utilities Commission only considers the utility bond yield and does not include government bonds in its ROE formula.

The current utility credit spread in the OEB formula is 1.415 percent. The long-term average utility credit spread since 2009 has been 1.493 percent, as shown in Figure 30 above. The 90-day average spread as of May 31, 2024, was 1.371 percent between the 30-year GOC bond yield and the A-rated Canadian utility bond yield. Concentric recommends that this spread be based on the 90-day average ending in September 2024, adding two additional months to the OEB's current approach to ensure that the observed spread is not too heavily influenced by recent events in the economy or capital markets.

An additional consideration is that not all Ontario utilities have an A-rating. At this time, Concentric is not recommending an adjustment to the credit spread (it would be wider), but this is an issue the Board should monitor for affected utilities. If the A and Baa/BBB+ bond spreads differ, the Board could average them or differentiate the resulting formula ROE separately for the A and sub A rated utilities.[100]

J. Utility Credit Spread Adjustment Factor

The adjustment factor for the utility credit spread in Ontario is currently set at 0.50 times the change from the base utility credit spread to the current utility credit spread**.** Similar to the adjustment factor for the LCBF, setting the adjustment factor at 0.50 times implies that for every 100-bps increase (or decrease) in the utility credit spread, it is reasonable to expect an approximately 50-bps increase (or decrease) in the utility cost of equity. Accordingly, the OEB formula incorporates this relationship by adding 0.50 times the change in utility credit spread, relative to the base utility credit spread, to the base ROE.

To determine updated adjustment factors for both the LCBF and utility credit spread, Concentric ran a multivariate regression analysis using historical data between January 1, 1993 and May 31, 2024. The regression tested U.S. authorized ROEs for electric and gas utilities, as the dependent variable, against both U.S. government bond yields and utility credit spreads as the independent variables, i.e.:

$$
\begin{aligned}
&Authorized\ ROE \\
&\qquad = Intercept + Coeff. * U.S. Government\ Bond\ Yield + Coeff. \\
&\qquad * Utility\ Credit\ Spread
\end{aligned}
$$

Where:

- "Authorized ROE" was the data stream of authorized ROEs from almost 1,700 U.S. gas and electric rate cases decided between January 1, 1993, and May 31, 2024;[101]

---

100 The BBB-rated utility bond debt spread is 30-50 basis points higher than the A-rated utility bond debt spread, with an average of 44 basis points over a 90-day period ending June 5, 2024.

101 Source: S&P Global rate case database.

- "U.S. Government Bond Yield" was the associated prevailing six-month trailing average 30-year U.S. government bond yield as of the rate case decision date;[102]
- "Utility Credit Spread" was the associated prevailing six-month trailing average Moody's A-rated utility bond yield spread over the 30-year U.S. government bond yield.[103]

The regression yielded a government bond yield coefficient of 0.3984 and a utility credit spread coefficient of 0.3340, with an R-squared of 0.5445. Based on this analysis, Concentric recommends lowering the LCBF adjustment factor from 0.50 to 0.40 and the utility credit spread adjustment factor from 0.50 to 0.33. These changes recognize that the relationship between ROEs and government bond yields has weakened slightly over the past fifteen years, while still maintaining the formula's ability to be sufficiently sensitive to changes in interest rates and utility credit spreads.

Using Concentric's recommended base ROE of 10.00 percent, a base LCBF as of May 31, 2024, an LCBF adjustment factor of 0.40, a base utility credit spread as of May 31, 2024, and a utility credit spread adjustment factor of 0.33, the annual OEB ROE formula would be as follows:

$$ROE = 10.00\% + 0.40 * (LCBF - 3.36\%) + 0.33 * (Utility\ Credit\ Spread - 1.371\ \%)$$

Concentric notes that the base LCBF (3.36%) and base utility credit spread (1.371%) noted above use data as of May 31, 2024. Concentric recommends updating these data closer to when a final decision is made in this proceeding.

K. Implied Equity Risk Premium

Figure 31 below provides a summary of the OEB's approach to determining an implied ERP based on the evidence of the experts in the 2009 proceeding. As shown in the table, the OEB derived the ERP based on either direct or derived estimates based on the model results provided by the experts, and

102 Series "USGG30YR Index" from Bloomberg Professional, as of May 31, 2024.
103 Series "MOODUA Index" from Bloomberg Professional, as of May 31, 2024.

it computed an average ERP of 5.5 percent, which is used in the formula. Combined with a forecast long-term GOC bond yield of 4.25 percent, this produced a 9.75 percent "Base ROE" that has been adjusted since by the formula.

Figure 31: OEB Implied ERP in 2009 Report

Table 1: Summary of Participant Recommendations

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

To calculate the equivalent ERP for the proxy companies using current market data, Concentric has relied on the results of the Multi-Stage DCF, CAPM, and Risk Premium models, discussed earlier, less the average projected 30-year Canadian and U.S. bond yields. We have used the North American Electric proxy group in this example. The results are summarized in Figure 32.

Figure 32: ERP for Proxy Group Based on Model Results

Utility Equity Risk Premium Estimate
North American Electric Proxy Group

Model	**ROE Estimate**	**Long Bond**	**Equity Risk Premium**
Multi-Stage DCF	9.83%	3.80%	6.03%
CAPM	10.23%	3.80%	6.43%
Risk Premium	9.90%	3.80%	6.10%
Average	**10.00%**	**3.80%**	**6.19%**

The average of these three approaches produces an ERP estimate of 6.19 percent, or 69 basis points higher than the 5.5 percent ERP estimate that the OEB derived in its 2009 Report.

L. Alternative ROE Formulas

Given the complexity of capital markets, it is reasonable to consider alternative methods for developing a formula that satisfies the Fair Return Standard. There are several methods to consider, including the following:

1) the California ROE formula, which is based solely on the annual change in Moody's utility bond yields;

2) the Pennsylvania approach, which uses a DCF model (tested for reasonableness by the CAPM) to set the authorized return used in Pennsylvania's "Distribution System Improvement Charge" ("DSIC") in years when the utility does not file a rate case; and

3) the recently implemented formula in Alberta, which employs an ERP method with slightly different parameters than those used in the current Ontario formula.

The following summarizes each of these alternative methods

1) **California**:[104] The California Public Utilities Commission adopted a cost of capital mechanism ("CCM") that originally took effect on January 1, 1990. Pursuant to the CCM, cost of capital COC proceedings are on a three-year cycle, with full COC applications due every third year for the following test year and a Formula Adjustment Mechanism operating in the interim years to adjust the authorized COC either upward or downward if interest rates change by a specified amount as compared to the relevant utility bond index. The CCM also preserves the utilities' right to file full COC applications under extenuating circumstances. The CCM was designed to streamline the COC process by eliminating the need for annual COC proceedings and providing greater predictability of the utilities' COC.

   The Formula Adjustment Mechanism is based solely on the change in utility bond yields. Moody's Aa utility bond index is used for utilities with credit ratings of AA or higher, Moody's A utility bond index is used for utilities with A ratings, and Moody's Baa utility bond index is used for utilities rated BBB or lower. In any year where the difference between the 12-month average of the applicable index and the benchmark exceeds a 100 basis point deadband, the Formula Adjustment Mechanism adjusts the utility's ROE either upward or downward by one half the difference between the index average and the benchmark interest rate.

2) **Pennsylvania**:[105] For utilities that are eligible to collect a DSIC, the authorized ROE is determined for regulated electric, gas, and water utilities in Pennsylvania based on a

---

104 California Public Utilities Commission, Application of Pacific Gas and Electric Company for Test Year 2022 Cost of Capital or, in the Alternative, for Suspension of Cost of Capital Mechanism for 2021, Application No. 21-08-015, August 23, 2021, p. 4-5.

105 Pennsylvania Public Utility Commission, Bureau of Technical Utility Services, Report on Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2021, Docket No. M-2021-3030045, Attachments D, F and G.

calculation performed by technical staff of the Pennsylvania Public Utility Commission ("PPUC"). On a quarterly basis, the PPUC staff determines a proxy group (called an industry barometer group) of companies based on screening criteria.

The ROE calculation is based on a DCF analysis, with a CAPM analysis to check the reasonableness of the DCF model results. The PPUC Staff uses specified inputs to the DCF and CAPM models, as described in the Bureau of Technical Utility Services Report on Quarterly Earnings of Jurisdictional Utilities.[106] The PPUC determines the ROE for DSIC purposes based on the range of reasonableness from the DCF barometer group data, CAPM data, recent ROEs adjudicated by the PPUC, and informed judgment. The ROE approved in a utility's most recent fully litigated base rate proceeding is utilized for the DSIC if it is less than two years old. Otherwise, the ROE is established based on the formula.

3) **<u>Alberta</u>**:[107] In October 2023, the AUC implemented a new ROE formula for Alberta's electric and gas utilities after having suspended the previous formula for approximately the last decade. The new Alberta formula is similar to the OEB formula with some minor differences. The AUC formula has a base ROE of 9.0 percent, and the return is adjusted annually based on changes in the 30-year GOC bond yield and the spread between 30-year GOC bonds and A-rated utility bonds as follows:

$$ROE_t = 9.0\% + 0.5 \times (\mathrm{YLD}_t - 3.10\%) + 0.5 \times (\mathrm{SPRD}_t - 1.58\%)$$

Under this formula, the authorized ROE in 2024 is 9.28 percent, or 28 basis points higher than a base of 9.0 percent established in 2023. The Ontario ROE declined by 15 basis points on a

[106] See: Bureau of Technical Utility Services, Report on The Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2021.

[107] Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond, Decision 27084-D02-2023, October 9, 2023.

year-over-year basis in 2024 from 9.36 percent to 9.21 percent under the same market conditions.

M. Recommendations

Based on the analysis set out in this Report, Concentric recommends the following modifications to the OEB's ROE formula:

1) Re-base the authorized ROE to 10.0 percent;
2) Should OPG propose and provide evidence for an ROE risk premium applicable to its pure-play regulated generation operation in its payment amounts application, the OEB consider that proposal at its discretion as part of that proceeding;[108]
3) Adopt the AUC's methodology for setting the LCBF. Specifically, we recommend that the LCBF be computed based on a weighted average of the projected 30-year GOC bond yield for the subsequent year as reported by RBC, TD Bank, and Scotia Bank (assigned 75% weight) and the current average 30-year GOC yield for the 90 days ending September 30 of each year (assigned 25% weight);
4) Update the average credit spread between the 30-year GOC bond yield and the A-rated utility bond yield as of September 30, based on a 90-day average;
5) Update the LCBF adjustment factor from 0.50 to 0.40;
6) Update the utility credit spread adjustment factor from 0.50 to 0.33.

[108] Consistent with the OEB's finding in EB-2009-0084 Report of the Board, p. 13.

LEI's Recommendation and Concentric's Response

LEI concludes that the OEB formula has met the Fair Return Standard since it was last revised by the Board in December 2009. Concentric generally agrees with LEI that the Ontario formula has produced returns that are generally consistent with those authorized for other Canadian electric and gas utilities in most years since 2009, with the exception of the years during COVID when interest rates were at or near historical lows while the equity risk premium increased substantially for all companies including regulated utilities. However, the OEB's formula return is substantially lower than the average authorized ROEs for comparable risk U.S. electric and gas utilities and therefore, in Concentric's view, is not sufficient to meet the Fair Return Standard.

LEI recommends several modifications to the existing OEB formula, including a change in the source of the LCBF (page 119 of LEI report), changes to the adjustment factors that are applied to the LCBF and the utility credit spread to update the formula each year (page 116 of LEI report), and a change to the implied equity risk premium (page 121 of LEI report). Concentric briefly responds to these recommendations below. LEI also recommends a change in the base ROE to 8.95 percent, which Concentric disagrees with and has addressed in Section V of our Report.

With respect to the source of the LCBF, Concentric agrees with LEI that it is preferrable to move to a forecast of the 30-year government bond. LEI has identified six major Canadian banks that provide interest rate forecasts, while Concentric has relied on the average of the three Canadian banks used by the AUC in its recently adopted formula. We agree with LEI that a 30-year government bond forecast is preferable to the current forecast of the 10-year government bond plus the 10/30 spread, although we believe it is also appropriate to also give weight to the current average GOC 30-year bond yield.

LEI recommends a 0.26 LCBF adjustment factor and a 0.13 utility credit spread adjustment factor based on a multivariate regression analysis considering both government and corporate bond yields. Concentric finds the following flaws with LEI's analysis:

- The LEI regression considers BBB-rated corporate bond yields rather than A-rated utility bond yields;
- The LEI regression considers the absolute level of corporate bond yields rather than spreads over government bond yields;
- As such, LEI's multivariate regression suffers from multicollinearity issues, in which the two independent variables are highly correlated, leading to results that are imprecise and subject to large volatility if presented with small variations in input data.

As a point of comparison, the characteristics of Concentric's and LEI's regression analyses are presented below. In part due to lower multicollinearity issues, Concentric's analysis yielded higher t-stats, indicating greater statistical confidence in the recommended coefficients, as well as tighter 95% confidence intervals for the coefficients, and a significantly greater f statistic indicating a more robust specification of the relationships. Due to these factors, Concentric disagrees with the results of LEI's analysis.

While Concentric agrees with LEI that coefficients have come down since 2009, our estimates indicate LEI's recommended adjustment factors are too low. Instead, Concentric recommends the OEB set adjustment factors at 0.40 for the LCBF and 0.33 for the utility credit spread, which recognizes the lower empirical relationship between ROEs and bond yields compared to previous years, while still maintaining the formula's sensitivity to changes in interest rates and utility credit spreads.

Multivariate Regression Results	**LEI Analysis**	**Concentric Analysis**
Number of data points	92 (aggregated quarterly)	1,693 (individual rate cases)
Government Bond Yield Adjustment Factor (Coefficient)	0.26	0.40
Government Bond Yield Coefficient 95% Confidence Interval	0.12 – 0.40	0.38 – 0.42
Government Bond Yield T-Stat	3.7795	43.9063
Utility Credit Spread Adjustment Factor (Coefficient)	0.13	0.33
Utility Credit Spread 95% Confidence Interval	0.01 – 0.25	0.28 – 0.39
Utility Credit Spread T-Stat	2.1573	12.7810
R Squared	0.6142	0.5445
Adjusted R Squared	0.6055	0.5440
F-Stat	70.8	1010.2

In the 2009 Report, the Board indicated that the implied ERP was 5.50 percent. The implied ERP based on LEI's recommendation is 5.76 percent, calculated by subtracting the risk-free rate of 3.19 percent from the average results of its CAPM analysis of 8.95 percent. Concentric's ROE analysis indicates that the implied ERP is higher, at 6.19 percent as shown above in Figure 32 of our Report.

VII. CAPITAL STRUCTURE AND RISK ASSESSMENT

A. Overview

In **Issue #11,** the OEB asked: "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?"

In **Issue #12**, the OEB asked: "How should the capital structure be set for electricity transmitters, electricity distributors, natural gas utilities, and OPG to reflect the FRS?"

Issue #13: the OEB asked: "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?"

In this section, we address those issues. Given the breadth of this proceeding in terms of its coverage of issues and industry segments, our analysis is performed at a higher level than would typically be performed in a utility-specific rate-setting proceeding. In doing so, we address four main questions: (1) Is the OEB's risk ranking of jurisdictional utilities, which has gas distributors at the lower end of the risk spectrum, electric distributors and transmitters in the middle, and OPG at the higher end of the risk spectrum, reflective of current industry business and financial risks? (2) Are Ontario equity thicknesses reasonably consistent with industry peers? (3) Does the OEB's approach to determining capital structures continue to be a reasonable approach for rate-making purposes? and (4) Is a different equity thickness warranted for single versus multiple asset transmitters?

To address those questions, Concentric performed the following steps:

1. Outlined the OEB's current approach to determining equity thickness and provided a brief summary of each industry segment's equity thickness history;

2. Reviewed other jurisdictions' approaches to determining equity thickness;

3. Summarized the risk profile of each utility industry segment, including the impacts of the Energy Transition on each segment, to assess the appropriateness of the current risk ranking

of Ontario utilities. This analysis also includes a review of debt and equity investor perspectives;

4. Compared the equity thicknesses of OEB-jurisdictional utilities to industry peers to assess the reasonableness of Ontario equity thicknesses vis-à-vis the comparability standard of the FRS; and

5. Developed recommendations.

B. Current Approach in Ontario

In the 2009 Report, the OEB described its capital structure policy as follows:

> - *The Board has determined that a split of 60% debt, 40% equity is appropriate for all electricity distributors. Capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy.*
> - *For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.*[109]

In its January 2016 "Review of the Cost of Capital for Ontario's Regulated Utilities," OEB Staff provided a summary of the cost of capital methodology, noting that it reflected the 2009 Report and subsequent letters and decisions, and that "[s]ubsequent letters and decisions have changed the timing for updates and the capital structure for rate-setting purposes for some utilities; the basic methodology determined in the 2009 Cost of Capital Report is unchanged."[110]

In that report, Staff summarized the capital structures authorized for each industry segment at that time:

109 EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 50.

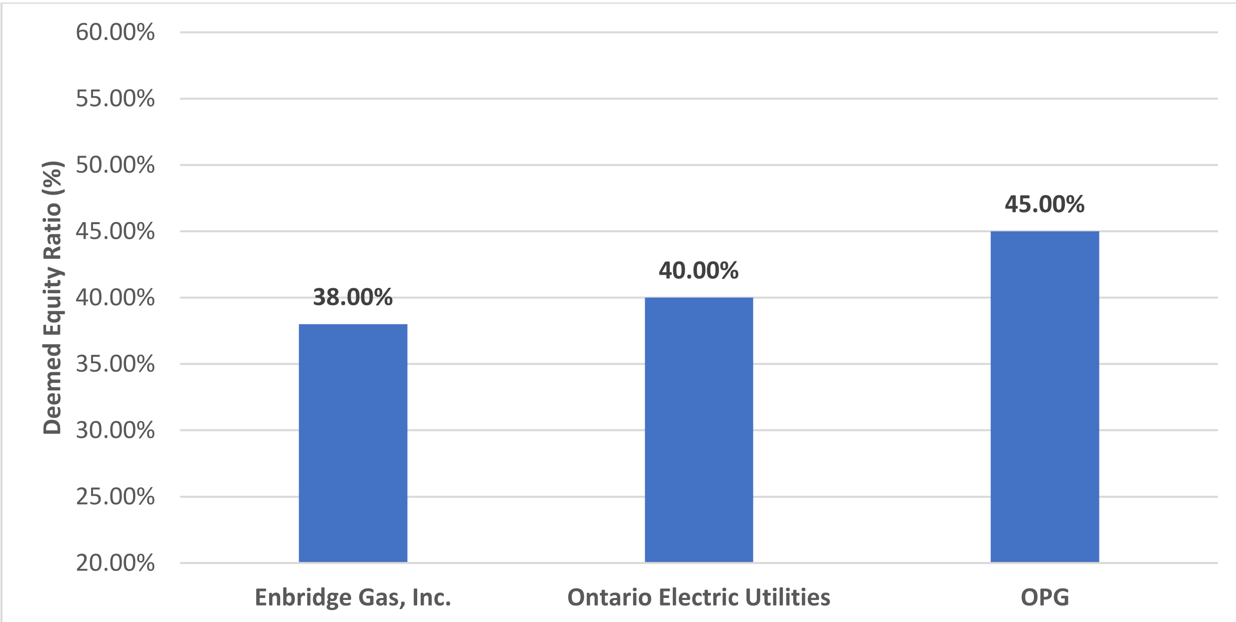
110 OEB Staff Report in EB-2009-0084, "Review of the Cost of Capital for Ontario's Regulated Utilities," January 14, 2016, p. 3.

Figure 33: OEB Staff Deemed Capital Structures (2016)

	Electricity Distributors and Transmitters	**OPG's prescribed generation assets**	**Natural Gas Distributors**		
			Enbridge Gas Distribution Inc.	**Union Gas Limited**	**Natural Resource Gas**
Deemed Capital Structure	40% equity, 56% long-term debt, 4% short term debt	45% equity, 55% debt, on rate base adjusted for the lower of Asset Retirement Obligations or Unfunded Nuclear Liabilities (EB2013-0321)	36% equity, 64% debt (combination of actual long-term, short-term debt and preferred shares)	36% equity, 64% debt (combination of actual long-term, short-term debt and preferred shares)	40% equity, 56% long-term debt, 4% short-term debt

As summarized by Staff, the OEB utilizes a different capital structure for ratemaking purposes for each industry segment: (1) natural gas distribution; (2) electricity distribution and transmission, and (3) OPG. In December 2023, the Board approved a deemed capital structure of 38 percent equity and 62 percent debt for Enbridge Gas. The other gas distributor, Natural Resource Gas, operates with a deemed capital structure of 40 percent equity and 56 percent long-term debt, and 4 percent short-term debt. For electric transmitters and distributors, the capital structure is set at 40 percent equity, 56 percent long-term debt, and 4 percent short-term debt. The capital structure for OPG's nuclear and hydroelectric generation assets is set at 45 percent equity and 55 percent debt (inclusive of short-term debt) on rate base adjusted for the lower of asset retirement costs and unfunded nuclear liabilities. The following figure provides the currently-authorized equity ratios for Ontario-jurisdictional utilities.

Figure 34: Ontario Utility Deemed Equity Ratios for Enbridge Gas, Inc., Electric Utilities, and OPG



The Board's approach to setting capital structure in Ontario has evolved through proceedings for gas and electric utilities. See Appendix A for a brief history of how the OEB has historically determined the deemed capital structure for each industry segment.

C. Other Jurisdictions' Treatment of Capital Structure

In the U.S., regulators most often determine the reasonableness of each utility's capital structure allowed in rates based on that utility's risk profile relative to its proxy group, comparison to peer equity ratios, credit metrics, and specific circumstances. The actual equity ratio maintained by the utility is also considered, and capital structure is considered each time the ROE is established, typically in a utility-specific rate proceeding.

In Alberta, the AUC takes a similar approach to the OEB, accounting for differences in business risk through the deemed equity ratio, while authorizing the same generic ROE for all utilities. The AUC places importance on ensuring that the authorized ROE and deemed capital structure are sufficient to achieve the credit metrics necessary to maintain a credit rating in the "A" range for a typical regulated utility. The BCUC in British Columbia and the Regie de l'Energie in Quebec take a somewhat different approach to business risk and capital structure. The BCUC historically set the authorized return for a benchmark utility (i.e., FortisBC Energy Inc.) and then adjusted the authorized ROE and deemed equity ratio of other electric and gas utilities in the province by comparison to the benchmark. The Regie sets a generic ROE for Hydro Quebec Distribution and Hydro Quebec Transmission (which are crown corporations) and accounts for differences in business risk through the deemed equity ratio. For gas distributors such as Energir and Gazifere, the Regie establishes a separate authorized ROE and deemed equity ratio for each company based on market data and an assessment of business risk.

While the Fair Return Standard requires that the return be sufficient to enable the utility to maintain its financial integrity, it is important to recognize that credit rating agencies represent different interests than equity analysts and institutional investors and that these parties therefore bring different perspectives to the issue of equity returns. In simple terms, credit rating agencies are concerned with the ability of a utility to meet its debt obligations as they come due. Significantly, the financial interests of debtholders rank higher in priority to equity holders, who receive compensation from residual earnings after debt costs and operating expenses are paid. While equity investors must consider the utility's financial and leverage risks since debt ranks higher than equity in the security waterfall, returns to equity investors and the attractiveness of utility equity investments are more directly dependent upon the level of earnings achieved by the utility.

D. Industry Segment Risk Profiles

As discussed previously, the risk for any company, including utilities, has two principal sources: business risk and financial risk.

These risks also have a time dimension. For a utility, short-term risks are those that will reverse or resolve themselves within a year or two, either through regulatory relief or the normal ebb and flow of earnings. Examples include earnings loss due to weather or losses that typically receive deferral account treatment or that would otherwise be included in a subsequent years' cost of service. Long-term risks represent an actual shift in the business risk profile of the company for which there is no foreseeable mitigation. Examples of long-term risks include: a sustained depressed business environment or changes in regulatory or environmental policies that impact the profitability of a company's operations.

Both short-term and long-term risks impact the utility business risk profile and are considered by investors. Investors will demand greater compensation for what they perceive to be higher risk, and seek comparable returns for comparable risks. The remainder of this section provides more details regarding our high-level business risk assessment related to climate risk, the Energy Transition, regulatory risk, financial risk, and the specific risk factors of each industry segment. Our conclusion is that risks for Ontario utilities have increased over time. That conclusion, coupled with our assessment that Ontario's equity ratios are low relative to industry peers, results in a recommendation that the OEB set a minimum deemed equity ratio for Ontario utilities of 45 percent, as discussed in more detail below.

1. Climate Risk

The intensifying risk of climate change has been a growing business and policy risk across the regulated utility industry. The utility industry faces the highest combined physical risk from climate hazards, which are increasing in their intensity and frequency because of rising temperatures.[111] Increased risk from wildfires, severe weather events, flooding, and rising water temperatures create new and likely ongoing financial and operational challenges for utilities to ensure timely recovery from these events while seeking to proactively safeguard their assets from future climate impacts. U.S. power companies, for example, were recently noted to be facing a USD 500 billion investment gap to properly prepare their assets for future events.[112] In Canada, the national adaptation strategy targets 80 percent of highly exposed businesses to include adaptation to climate change in plans and strategies by 2027 in order to strengthen their competitiveness. Energy is one of the highest risk sectors included in this target.[113] Further, the Ontario government has recently recognized this increased risk for utilities, for instance in its Vulnerability Assessment for Ontario's Electricity Distribution Sector, where Ministry of Energy found that "[i]n addition to direct physical risks to their systems, evidence suggests that utilities face secondary financial, legal and reputational risks as a result of climate change, particularly if they fail to take action to adapt."[114] Further, the OEB has initiated the Vulnerability Assessment and System Hardening ("VASH") project to "address the ask

---

[111] S&P Global, "Utilities Face Greatest Threat as Climate Risks Intensify," September 20, 2021, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utilities-face-greatest-threat-as-cl-risks-intensify-66613890

[112] Ibid.

[113] Government of Canada, "Canada's National Adaptation Strategy: Building Resilient Communities and a Strong Economy", 2023 p. 29.

[114] Governance, Strategy and Analytics Branch, Ministry of Energy, "Vulnerability Assessment for Ontario's Electricity Distribution Sector," p. 10.

from the Minister of Energy (now Energy and Electrification) to develop and implement policies to improve distribution sector resiliency in response to the challenges posed by climate change."[115]

Climate risk is not solely an internal issue that utilities must manage, but one that is increasingly assessed by investors and rating agencies. For example, in an S&P Global March 2024 report, the agency noted that ESG-related rating activity in the utilities and energy sectors, excluding any rating actions related to COVID-19, has become more pronounced relative to other sectors. Moreover, utility and energy companies have been under more strain given the increase in climate-change related events.[116] Climate risk and the vulnerability of utilities' assets have increased since the OEB's last generic cost of capital proceeding, as demonstrated by the number of negative rating actions: S&P Global downgraded only two investor-owned utilities from 2005 to 2017, and downgraded nineteen utilities from 2018 to 2023.[117] The intensification and higher frequency of climate-related events will continue to put additional financial and operational pressure on Ontario's utilities, emphasizing the necessity to maintain strong balance sheets and the ability to attract capital.

Investors, central banks, and financial regulators have increasingly recognized over the last five years the risk of climate change to the economy, the stability of the financial system, and specific industries and investments. Examples include:

In May 2019, the Bank of Canada indicated that it views climate change as an emerging risk for the Canadian economy and financial system. Specifically, the Bank of Canada has observed that:

> *Climate change continues to pose risks to both the economy and the financial system. These include physical risks from disruptive weather and events and transition risks from adapting to a lower carbon global economy.*[118]

The Bank of Canada indicates that it is incorporating climate change risk into its analysis of the Canadian economy and financial system, that climate change creates important physical risks in

115 OEB VASH webpage (https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/vulnerability-assessment-and-system), accessed on July 17, 2024.

116 S&P Global, "ESG in Credit Rating Deep Dive: ESG Factors Drove 13% of Corporate and Infrastructure Rating Actions Since 2020," March 13, 2024, p. 8.

117 S&P Global, "A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality," November 9, 2023, https://www.spglobal.com/ratings/en/research/articles/231109-a-storm-is-brewing-extreme-weather-events-pressure-north-american-utilities-credit-quality-12892106

118 Bank of Canada Financial System Review-2019, May 2019, p. 28.

Canada and globally, and that the move to a low carbon economy involves complex structural adjustments, creating new opportunities as well as transition risk.[119]

In its 2022 "Disclosure of Climate-Related Risks," the Bank of Canada further found that:

> *Climate-driven economic volatility could complicate the Bank's roles in conducting monetary policy and promoting financial stability and could also plausibly affect the value and creditworthiness of the assets it holds as investments or collateral.*
>
> ***
>
> *The transition to net-zero emissions will affect almost every sector of our economy and countless Canadians. For Canada's oil and gas sector, the change will be profound as global demand for fossil fuels diminishes. And for many other sectors—from agriculture to manufacturing, transportation and electricity—the implications are likely to be far-reaching.*[120]

In September 2020, the Commodity Futures Trading Commission, the financial regulator that oversees the trading of futures and options in the U.S., published a report concluding that climate change is a risk to the U.S. financial system.[121]

Rating agencies have incorporated ESG criteria into their credit rating analyses, while other investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change. For example, in January 2020, investment manager BlackRock sent a letter to its clients announcing a number of initiatives to place sustainability at the center of its investment approach, including: making sustainability integral to portfolio management; exiting investments that present a high sustainability-related risk; and strengthening its commitment to sustainability and transparency in investment stewardship activities. [122]

In summary, increased climate risk and the energy transition require utilities to be financially prepared and flexible to withstand financial pressures associated with response to these risks, whether in the form of after-the-fact action or proactively increased resilience. Utilities must be in a

---

119 *Ibid*., p. 28-29.
120 Bank of Canada Disclosure of Climate-Related Risks 2022 (accessed at www.bankofcanada.ca, July 17, 2024).
121 U.S. Commodity Futures Trading Commission, "Managing Climate Risk in the U.S. Financial System," September 9, 2020.
122 BlackRock Letter to CEOs, "A Fundamental Reshaping of Finance," January 20, 2020.

financial and regulatory position to accommodate increased expenditures, reduced operational flexibility and/or reduced outputs. Furthermore, utilities' capital structures must be sufficiently balanced to ensure access to capital and the ability to earn comparable risk-adjusted returns.

2. Energy Transition

Utilities are evolving their corporate strategies to meet jurisdictional climate policies and goals. At an accelerating pace over the last decade, the global energy sector has embarked on a broad-scale transformation, referred to generally as the "Energy Transition," from a primary reliance on fossil fuels to an increased emphasis on more renewable fuel sources.[123] As a result, the risk profile of utilities in North America has fundamentally changed, with utilities facing significant risks and costs going forward.

In its December 2023 report, the Electrification and Energy Transition Panel ("EETP") noted that in the medium term (i.e., 2030-2050) the Energy Transition will enter an intense transformation affecting every part, sector, and community in Ontario, leading to the establishment of a clean energy economy.[124] Globally, investment in clean energy is already underway with an expected USD 2 trillion going to clean energy technologies and infrastructure in 2024,[125] and an estimated requirement of USD 4 trillion in clean energy investment to support global decarbonization by 2030.[126] As utilities plan and execute infrastructure projects to meet policy mandates and reduce climate risk, the increased demand for labor, supplies, and capital, as well the development of new technologies, will create constraints, increase costs and consequently increase the risks (and commensurate return requirements) associated with investment in their securities.

Furthermore, the Energy Transition and associated deeper reliance on electricity will decrease the tolerance for electrical power interruptions, further necessitating the investment in safety and reliability of utility assets. In March 2024, Ontario's Ministry of Energy published its Vulnerability

---

123 S&P Global, "What is Energy Transition," February 24, 2020. https://www.spglobal.com/en/researchinsights/market-insights/what-is-energy-transition.

124 Electrification and Energy Transition Panel, "Ontario's Clean Energy Opportunity," January 2024.

125 International Energy Agency, "World Energy Investment 2024," https://www.iea.org/reports/world-energy-investment-2024/overview-and-key-findings

126 Electrification and Energy Transition Panel, "Ontario's Clean Energy Opportunity," January 2024.

Assessment for Ontario's Electricity Distribution Sector, which evaluated the impacts of climate change on the industry. The vulnerability report notes:

> *There is a need for proactive investment into climate resilience and adaptation, particularly since reliance on electricity in the province is anticipated to increase. Current actions and policies will have significant impacts on Ontario's distribution system, particularly in the context of demand management. Examples of this include Canada's Net-Zero 2050 legislation and other policies that promote the adoption of electric vehicles and fuel-switching for space and water heating.*[127]

Decarbonization and the resulting electrification of the energy system will uniquely impact the electric and gas utilities, and OPG, as described below.

Electric Distributors and Transmitters

Electric distributors and transmitters will need to secure sufficient electricity supplies and grid reliability as significant demand growth occurs for electric power. Electric distributors and transmitters will need to invest in assets as interconnectivity from energy sources to the customer becomes fundamental in supplying increased loads to meet demand. Given the expected higher reliance on electricity as it further displaces natural gas, electric distributors and transmitters will increasingly prioritize reliability and safeguarding their assets amid increased environmental risks, necessitating increased levels of investment in the electric system. Uncertainty about the pace of the Energy Transition will also increase planning risk in the near-term for electric distributors and transmitters.

Natural Gas Distributors

Natural gas distributors face the risk of a decline in demand and potential asset decommissioning as customers switch to alternative sources of energy. Moreover, initiatives aimed at reducing emissions raise concerns about the future viability and competitiveness of the gas distribution business model.

For example, Moody's observed:

> *Emissions reduction initiatives call into question the long-term ability of LDCs to maintain their position as natural gas monopoly service providers. Efforts in some*

[127] Governance, Strategy and Analytics Branch, Ministry of Energy, "Vulnerability Assessment for Ontario's Electricity Distribution Sector," p. 90.

> *jurisdictions to reduce greenhouse gas emissions as they transition to a low-carbon future may threaten the ability of LDCs to remain competitive. Government incentive programs are likely to accelerate the adoption of electric alternatives to natural gas usage, while clean energy innovations will expose the sector to technology risk. While there are still significant barriers to replacing LDCs, continued policy and regulatory support will be necessary to facilitate the sector's energy transition and maintain credit quality over the long term.*
>
> *Government emissions reduction targets can weaken the competitive position of LDCs. Policies requiring significantly lower emissions could either eventually reduce the size of LDCs over time, drive up their costs or both.*[128]

Despite these risks, gas utilities will need to continue to invest in their assets to ensure safety and reliability for the remaining customers on the gas distribution system. As more customers shift from natural gas to electricity, natural gas distributors will face a higher risk for cost recovery as costs are spread over a fewer number of customers.

> *Although natural gas transportation and distribution companies continue to provide generally safe, reliable service while reducing emissions, there are ESG reputational risks associated with any hydrocarbon-based business, including financial governance policy risks around a higher cost of capital and lower asset returns over a multi-decade time horizon. Events like the August 2020 Baltimore explosion exact heavy social costs related to customer relations and public health and safety. Financial risks also stem from the likelihood of construction delays and greenfield project budget overruns, potential cancellations, regulatory fines and penalties for accidents, increasing debt obligations associated with gas infrastructure expansion and potential write-offs of stranded assets as the carbon transition progresses.*[129]

Gas distribution utilities may also seek to adopt alternative fuels in their existing systems to support the transition and net-zero greenhouse gas ("GHG") emissions. There are two commonly identified fuel alternatives for gas distribution utilities to comply with net-zero targets: hydrogen and renewable natural gas ("RNG"). However, pursuing those pathways carries risk from an investor's perspective, as well as incurs a substantial cost for the customer, reducing the natural gas competitive price differential with electricity. Introduction of alternative fuels into the existing gas distribution

[128] Moody's Investors Service, "Sector In-Depth: Emissions Reduction, Electrification Threaten Long-Term Competitiveness," November 14, 2022, p. 2.

[129] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, p. 2.

system allows for continued utilization of existing gas pipeline infrastructure, but creates risks and costs for LDCs in adapting new technologies and methods for delivering energy to customers.

Investors are acutely aware of the Energy Transition risk that natural gas utilities currently bear and seek returns commensurate with the increased risk of uncertainty resulting from environmental policy and increased focus on ESG. S&P Global noted this in its June 28, 2024 report on Enbridge Gas where it stated that S&P Global's negative outlook on Enbridge Gas "reflects the uncertainty around upcoming regulatory outcomes related to EGI's gas utility operations and the potential for increased business risk from the energy transition."[130] S&P Global further found:

> *The negative outlook on EGI over the next 12 months reflects the uncertainty around upcoming regulatory outcomes related to EGI's gas utility operations and the potential for increased business risk from the energy transition. OEB believes this is underway, creating a risk of stranded assets for EGI, which could impede EGI's long-term capital spending initiatives, indicating higher business risk.*[131]

Ontario Power Generation

OPG's risks related to the Energy Transition are subsumed in many of its company-specific risks that have increased as OPG invests in its facilities and builds new power plants to meet increasing electricity demand. To that point, OPG's role as a regulated electricity generator puts the company in a unique position to meet growing demand as electrification and clean energy goals advance as part of the Energy Transition, but this will require large upfront investment and carries a wide range of risks associated with construction.

As Moody's noted in its June 2024 report on OPG, OPG's already large capital program is expected to grow rapidly over the coming years.[132] In addition to involving new technologies that carry additional or first-of-a-kind risks, OPG's projects face risks such as increased competition for labour expertise, vendor capacity and materials availability in the face of a growing number of infrastructure projects in Canada and globally.[133] There are also inherent environmental, technical regulatory, licensing and other approval risks for new generation facilities. For example, OPG's Darlington New Nuclear Project

130 S&P Global, "Enbridge Gas Inc. 'A-' Rating Affirmed; Outlook Remains Negative," June 28, 2024, p. 1.
131 Id., p. 2.
132 Moody's Ratings, "Credit Opinion: Ontario Power Generation Inc.," June 24, 2024, p. 5.
133 Ontario Power Generation Inc. Management's Discussion and Analysis for the period ended December 31, 2023, pp. 67-72.

is implementing SMRs that will produce approximately 1,200 megawatts ("MW") of electricity to meet increasing demand from electrification and Ontario's net-zero goals.[134] As further discussed below, while the project is supported by the Ontario government, heightened capital spending and significant execution risk associated with this first-of-a-kind technology are additional risk factors that are considered by investors as they assess the appropriate level of return.

In terms of environmental-related risks for OPG, Moody's stated:

> *OPG's E-3 score reflects exposure to physical climate risks mostly due to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets also have exposure to waste management and pollution risks. While the company has not had any issues with its nuclear fleet or nuclear waste, it remains an inherent risk for nuclear operators. The company has limited exposure to carbon transition risks owing to its portfolio of primarily nuclear and renewable assets.*[135]

For OPG, the heightened risks extend beyond its nuclear programs. For example, for OPG's hydroelectric business, the Energy Transition introduces procurement risks given a limited number of turbine and generator suppliers meeting increased global demand.

Financial Implications

Utility executives have discussed a potential tripling of electricity demand by 2050.[136] This increase will drive unprecedented capital needs in the electric industry as utilities seek to meet demand while continuing to provide safe and reliable service. In its 2024 industry outlook, consultancy Deloitte summarized the near-term capital needs of the industry as follows:

> *As power and utilities sector capital expenditures reach new heights and continue to rise well into 2024, companies are exploring a variety of funding sources to help foot the bill. S&P's sample group of large energy utilities is expected to spend nearly US$171 billion in 2023, up more than 18% YoY, and projected to rise further in 2024 to 2025. Costs are mounting to upgrade and modernize the grid, harden it against severe weather, prepare for rising demand, and source more renewable energy. Rising interest rates and inflation could continue to boost costs in 2024.*[137]

---

134 https://news.ontario.ca/en/release/1003248/ontario-building-more-small-modular-reactors-to-power-provinces-growth.

135 Moody's Ratings, "Credit Opinion: Ontario Power Generation Inc.," June 24, 2024, p. 7.

136 S&P Global, "Utility execs prepare for 'tripling' of electricity demand by 2050," April 19, 2023.

137 Deloitte, "2024 Power and Utilities Industry Outlook," December 4, 2023.

This spending will pressure credit profiles, enhancing the need for regulation that supports timely recovery of costs and access to capital. As found by S&P Global:

> *The industry's capital spending remains at record levels, supporting initiatives for safety, reliability, energy transition, and growth. We consider these trends long term and expect that capital spending will only continue to increase over this decade. Accordingly, cash flow deficits have increased, pressuring the industry's*
>
> *credit quality. For 2024, our base case assumes that the industry will fund its approximate $85 billion of cash flow deficits with about $40 billion in asset sales and equity issuance.*[138]

For natural gas utilities, the financial implications of the Energy Transition are different but even more acute, particularly over the longer term. Specifically, a risk to LDC operations is that a significant portion of gas plant investments could become stranded. Generally, the term "stranded asset" refers to an investment that becomes no longer used or useful in the provision of service to customers before the end of its depreciable life. At that point in time, the undepreciated value of the asset (i.e., its net book value) is "stranded" with costs to be borne by either investors or customers. Gas distribution utilities such as Enbridge Gas, Inc. generally depreciate capital invested in their systems over the expected useful life of the underlying physical property, which is often many decades. Therefore, the Energy Transition creates stranded asset risk for the Company by introducing the possibility that significant portions of the Company's property will cease being used or useful before it is fully depreciated. As noted above, S&P Global has identified stranded asset risk as increasing for Enbridge Gas S&P Global further observes more broadly for the industry:

> *While new pipelines have faced fierce opposition from environmental activists and local communities since the initial shale gas development boom and the pace of new projects has declined in recent years, the specter of stranded assets did not really emerge for existing gas pipelines and the gas LDCs until recently when the zero-carbon movement picked up steam.*[139]

---

138 S&P Global, "Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens," February 14, 2024.

139 S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, p. 10.

3. Cyber Security Risk

As owners and operators of critical infrastructure, utilities face a heightened risk from cyber security breaches, in addition to the typical risks borne by all other sectors (e.g., personal information and data breaches, ransomware attacks, etc.). The urgency to upgrade legacy systems (both essential business platforms, and those technologies specific to the energy sector) is felt more severely by utilities, as reflected in the OEB's evolving cyber security requirements.[140] Utilities are also increasingly expected to invest in technological upgrades to better manage their assets and operations, but these advancements may complicate or increase the cost of cyber security readiness. Cyber security issues are a critical issue for utilities and regulators. For example, Colonial Pipeline experienced a ransomware attack in May 2021.

In a November 2021 report, S&P Global noted the following about cyber-attacks:

> *Cyber attacks on utilities have increased substantially year-over-year and while most U.S. attacks have been domestic in origin, globally, utilities have been the target of nation states or rogue actors seeking to disrupt operations. In particular, there were several reported breaches of informational (IT) and operational technology (OT) assets, in 2020 and 2021, resulting in data and financial loss and compromised assets, through phishing and other techniques.*
>
> *The risks are not just financial. Cyber attacks can cause reputational, regulatory, and financial risks if information breaches occur. These events may also influence a utility's relationship with the customer base, weakening management's rate-setting flexibility. In addition to our evaluation of IT exposures and general cyber hygiene, utilities have a number of potential OT vulnerabilities related to supervisory control and data acquisition (SCADA) systems among other physical asset considerations.*[141]

In its 2023 Form 10-K, Enbridge, Inc. (parent of Enbridge Gas) included cyber-security risk as one of the risks it discloses to investors related to operational disruptions and catastrophic events. In discussing cyber-security risk, Enbridge, Inc. states:

> *Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication of cyber attacks and financially motivated cybercrime, as well as due to international and domestic political factors including*

140 See, the Ontario Cyber Security Framework webpage on the OEB's website, accessed on July 18, 2024.
141 Standard and Poor's Global Ratings, "Cyber Risk in a New Era: US Utilities are Cyber Targets and Need to Plan Accordingly," November 3, 2021, p. 2.

> *geopolitical tensions, armed hostilities, war, civil unrest, sabotage, terrorism and state-sponsored or other cyber espionage. Because of the critical nature of our infrastructure and our use of information systems and other digital technologies to control our assets, we face a heightened risk of cyber attacks, such as ransomware, theft, misplaced or lost data, programming errors, phishing attacks, denial of service attacks, acts of vandalism, computer viruses, malware, hacking, malicious attacks, software vulnerabilities, employee errors and/or malfeasance, or other attacks, security or data breaches or other cybersecurity incidents. Cyber threat actors have attacked and threatened to attack energy infrastructure, and various government agencies have increasingly stressed that these attacks are targeting critical infrastructure, including pipelines, public utilities, and power generation, and are increasing in sophistication, magnitude, and frequency.*[142]

The International Energy Agency ("IEA") reports that there is increasing evidence that cyberattacks on utilities have been growing since 2018, with critical infrastructure such as gas, water and power utilities as the "favoured targets" for malicious cyber activity.[143] In Ontario, the potential for heightened cyber security risk was a focus in the OEB's March 2024 Notice of Amendments to Codes to Enhance Cyber Security Readiness.[144] In its discussion, the OEB noted that there is potential for heightened cyber security risk as the Energy Transition proceeds and new technologies are integrated into the electricity system.[145]

4. Regulatory Risk in Ontario

Investor Perspectives

Concentric's view is that the perspectives of debt and equity investors in the utility sector are one of the most relevant considerations in setting the cost of capital parameters and capital structure. From a practical perspective, the views of capital market participants provide important feedback on the reasonableness of the authorized cost of capital and whether the financial integrity, capital attraction and comparable return standards are being met. Relevant sources of information include credit reports on the utility industry, debt and equity investor rankings of Ontario's regulatory environment, and credit and equity analyst reports for individual utilities. We believe the OEB should consider this type of information when it conducts periodic reviews to determine whether the

---

142 Enbridge Inc. 2023 U.S. Securities and Exchange Commission Form 10-K, p. 49.
143 International Energy Agency, "Cybersecurity – is the power system lagging behind?" August 1, 2023
144 Ontario Energy Board, "Notice of Amendments to Codes to Enhance Cyber Security Readiness," March 27, 2024 in EB-2023-0173.
145 Ibid.

authorized ROEs and deemed capital structures of Ontario's regulated utilities are sufficient to ensure ongoing access to capital on reasonable terms. Further, we believe the credit ratings of Ontario's utilities should be viewed by the Board as a minimum threshold, not as a maximum (or as the basis for lowering the authorized ROE or the deemed equity ratio), because, as noted, it is the availability of equity capital that is more directly dependent upon the level of a utility's earnings.

In response to the questions raised in Issue #11, Concentric considered the views of equity investors and credit rating agencies as it relates to the regulatory environment in Ontario as compared to other Canadian and U.S. jurisdictions. S&P Global assesses Ontario regulation as "most credit supportive" noting that:

> *S&P Global Ratings considers the province of Ontario to have predictable and stable regulatory frameworks for electricity and gas transmission system operators (TSOs) and distribution system operators (DSOs). This results in our assessment of Ontario regulation--which is administered largely by the Ontario Energy Board (OEB), the key source of our information--as strong (the most credit supportive assessment). We evaluate jurisdictions by the qualitative and quantitative factors that affect the regulatory advantage for the utilities we rate. We view the regulatory framework as the single most important factor in assessing a regulated utility's competitive position.*[146]

In March 2024, S&P completed a review of Ontario, leaving its assessment unchanged.[147] In spite of this generally favorable view of Ontario's regulatory framework, S&P Global has previously cautioned investors about the ROE formula as follows: "In addition, the formulaic approach for calculating the approved ROE may result in lower approved ROEs in the currently prevailing low-interest-rate environment and pressure the financial metrics."[148]

UBS, an investment bank, ranks regulatory jurisdictions in the U.S. and Canada for purposes of determining whether to apply valuation discounts or premiums to the utility stocks it covers. Specifically, UBS places regulatory jurisdictions into five tiers based on the following equally weighted criteria: (1) whether commissioners are elected or appointed, (2) allowed returns relative to 10-year Treasury notes, (3) mechanisms that reduce regulatory lag, (4) rate and customer bill

[146] S&P Global, "Why We See Ontario's Electricity and Gas Regulatory Framework as Strong," January 13, 2021, p. 1.

[147] S&P Global, "North American Utility Regulatory Jurisdictions Update: Ontario Remains Unchanged, Notable Developments Elsewhere," March 11, 2024.

[148] S&P Global, "Why We See Ontario's Electricity and Gas Regulatory Framework as Strong," January 13, 2021, p. 1.

levels, (5) the tendency to settle or litigate rate cases, and (6) a subjective "investor friendliness" factor.[149] UBS ranked Ontario's regulatory environment in tier three out of five (with one being the best) in a December 2023 report.[150] UBS placed British Columbia in tier one, Ontario, Newfoundland and Labrador, Nova Scotia, and Prince Edward Island in tier three, and Alberta in tier five.

Debt and equity investors' perspectives inform the reasonableness of the cost of capital, risk and attractiveness of a utility investment relative to the market. For example, in their most recent updates to their credit reports, Moody's[151] and S&P Global[152] both noted the high levels of execution risk in OPG's ongoing refurbishment of the Darlington Nuclear Generating Station and planned refurbishment of four reactors at the Pickering Nuclear Generating Station that could pressure the company's credit quality over time. While Moody's also noted that the risk associated with the Darlington refurbishment has diminished as the project has been proceeding, Moody's notably highlighted that the Darlington SMR project carries "very high levels of execution risk"[153] with "uncertainty around regulatory support during construction."[154] Additionally, Moody's increased, from 12% to 15%, the quantitative threshold for the CFO pre-WC/debt ratio that OPG is measured against for the current credit rating. Both S&P Global and Moody's note that they rate OPG three notches below their respective OPG corporate credit ratings on a stand-alone basis (that is, before considering support by the Province of Ontario), namely as "BB+" and "baa3", respectively.

Investors' perspective of ratemaking outcomes is another important consideration in the evaluation of the cost of capital. For example, Moody's primarily attributes Hydro One's weak financial metrics to the utility's low deemed equity ratio:

> *We expect cash flow from operations to be predictable but financial metrics to decline modestly as the benefits of a favorable tax decision from the OEB expires. We forecast CFO Pre W/C to debt of 11-13% in the next few years. These relatively weak financial metrics are primarily the result of its low authorized equity layer in the capital structure*

149 UBS Global Research, "North America Power & Utilities: Mind the Gap(s): 2021 Utility Outlook," December 14, 2020, p. 5.
150 UBS Global Research, "US Utilities 2024 Outlook: A Year for Resolutions and Resolve," December 12, 2023, p. 12.
151 Moody's Ratings, "Credit Opinion: Ontario Power Generation Inc.," June 24, 2024.
152 S&P Global, "Ontario Power Generation Inc.," August 8, 2023.
153 Moody's Ratings, "Credit Opinion: Ontario Power Generation Inc.," June 24, 2024, p. 1.
154 Id., p. 6.

> *(currently 40%) that is established by the OEB, as well as low depreciation rates that are a function of long-life T&D assets.*[155]

As another example, in a recent report on Enbridge Gas, S&P Global comments favorably on the OEB's regulatory framework, but also describes the "uncertainty around upcoming regulatory outcomes related to EGI's gas utility operations and the potential for increased business risk from the energy transition."[156]

Investors' perception of higher financial, project execution, and regulatory risk signals that an investment in the utility's equity should constitute a higher return commensurate with that risk. During times of high capital spending (such as during the Energy Transition) or evolving financial conditions, the ability to attract capital at a reasonable cost is of paramount importance. Periodic regulatory reviews of established ROEs and capital structures taking into account these factors can assist in enabling a utility's ability to access the capital markets.

E. Regulatory Risk of Ontario's Utilities Compared to the Proxy Groups

The companies in the North American Electric, North American Gas and North American Combined proxy groups were selected as being the most risk comparable to Ontario's regulated electric and gas utilities. To evaluate the comparability of the North American proxy groups, we examined the regulatory and financial risks of the North American proxy group companies relative to those of typical Ontario electric and gas utilities to determine whether any adjustments should be made to account for differences in regulatory and financial risk between the North American proxy groups and Ontario's utilities.

We started by comparing the regulatory risk of Ontario's electric and gas utilities against the operating companies held by the North American proxy groups. In general, we found that the operating utilities held by the North American proxy groups have cost recovery mechanisms and adjustment clauses that mitigate certain business and financial risks of a regulated utility. We also observed that as a pure-play generation utility, OPG's business risk is not entirely reflected in the North American proxy groups. With that in mind, we then examined the comparability of the groups across the following:

155 Moody's Ratings, "Hydro One Inc.: Update to credit analysis," May 30, 2023.
156 S&P Global, "Enbridge Gas Inc. 'A-' Rating Affirmed; Outlook Remains Negative," June 28, 2024, p. 2.

Credit Rating: The average S&P Global credit rating for the operating utilities held by the North American proxy group is A-. Credit ratings take into account both business and financial risk from the perspective of debt investors, who are concerned with the timely repayment of debt obligations. By comparison, S&P Global credit ratings for Ontario's electric and gas utilities range from BBB+ to A.

Test Year Convention: Approximately 43 percent of the operating utilities held by the proxy group companies provide service in a jurisdiction that uses a forecast or partially forecast test year, which reduces regulatory lag and enables timely cost recovery, while 57 percent operate in jurisdictions that use a historical test year adjusted for known and measurable changes. Ontario's electric and gas utilities use forecast costs in setting rates in their most recent PBR plans. On this factor, the Ontario electric and gas utilities have somewhat lower business risk than almost half of the operating utilities held by the North American proxy groups, although this risk offset diminishes as the link between costs and rates is deliberately severed under Ontario's PBR model.

Fuel Price Risk: Like the Ontario utilities, the North American proxy group companies have little to no exposure to commodity price risk or supply risk due either to the elimination of the utility supply function in competitive electric and gas markets or through the prevalence of fuel pass-through mechanisms – 100 percent of the proxy companies are protected from normal commodity price risk. On this factor, the Ontario electric and gas utilities (other than OPG who bears risk for nuclear fuel costs) have comparable business risk to the companies in the North American proxy groups.

Volumetric Risk: Approximately 62 percent of the operating utilities held by the North American proxy groups are protected from market (or demand) risk by full or partial revenue decoupling mechanisms. The majority of Ontario's electric distribution utilities also have a regulatory mechanism to mitigate volumetric risk, at least for residential customers, but not for commercial, institutional, and industrial loads. Enbridge Gas currently has regulatory mechanisms that provide partial volumetric risk mitigation, in regards to average use changes, but Enbridge Gas is still subject to weather volumetric risk. In Enbridge Gas's 2024 rebasing application, Enbridge Gas applied for Straight Fixed Variable ("SFV") rate design that would mitigate both average use and weather volumetric risk, if approved. The SFV proposal will be heard as part of a subsequent phase of the proceeding expected to commence later this year or in early 2025. Following approval, SFV would be implemented after required billing system changes are made. On this factor, Ontario electric distribution utilities have roughly similar business risk as approximately three-fifths of the North American operating companies in the comparator groups, and Enbridge Gas's SFV rate design, if approved, would also mitigate volumetric risk for Enbridge Gas. Further, OPG continues to be at risk for variability in the generation output, a factor that distinguishes OPG from other North American regulated generators. This risk pervades and compounds OPG's other nuclear risks, discussed below.

Capital Cost Recovery: Approximately 87 percent of the operating companies held by the North American proxy groups have capital cost recovery mechanisms that allow them to recover capital costs between rate cases. These include capital costs for conservation programs, renewable and other forms of generation, environmental compliance, delivery infrastructure, and transmission. In particular, regulatory lag is mitigated by the use of generic infrastructure riders, capital trackers, and deferral accounts which are employed by the vast majority of the companies in the North American proxy groups. Under the most recent PBR plans, Ontario's electric and gas distribution utilities also have the ability to recover capital costs as new plant investments are placed in service. On this basis, Ontario's utilities have similar business risk as the operating companies held by the North American proxy groups.

In summary, we find the aggregate business risk profiles of the North American proxy groups reflect similar risk as the Ontario electric and gas utilities, other than OPG. These Ontario utilities are closely aligned with the North American proxy groups in terms of commodity price risk and the use of infrastructure recovery mechanisms such as riders and capital trackers. We also find a comparable level of regulatory protection for mitigating regulatory lag through the use of deferral accounts. In addition, several of the Ontario utilities are exposed to fluctuations in throughput due to changes in load or loss of customers, while more than 60 percent of the North American proxy group utilities are protected from volumetric risk through decoupling mechanisms.

F. Financial Risk of Ontario's Utilities Compared to the Proxy Groups

Financial risk exists to the extent a company incurs fixed obligations that are senior to common equity in financing its operations. These fixed obligations increase the level of income that must be generated to cover interest payments before common stockholders receive any return, directly impacting equity investors.

Fixed financial obligations also reduce a company's financial flexibility and its ability to respond to adverse economic circumstances and capital market conditions, such as those during the credit crisis and financial market disruptions of 2008/2009 and more recently during the early days of the COVID-19 pandemic in the spring of 2020. The equity in the capital structure, besides providing a return that compensates equity owners for their investment, serves to buffer unanticipated earnings swings.

If the equity layer becomes too thin, lenders will become concerned that the company may not be able to meet its fixed debt obligations and will require a higher yield to compensate for the additional risk. Additionally, as the authorized equity layer is reduced, earnings are also reduced such that an unexpected earnings disruption has a greater impact due to the thinner equity layer. Shareholders require a higher return to compensate for this increased risk to their investment return. Accordingly, an appropriate equity ratio benefits both shareholders and customers by reducing overall financing costs and sustaining capital through all market cycles.

Financial risk is assessed in terms of capital structure, credit rating, credit metrics, and authorized return (capital structure and authorized return span both major risk areas, i.e., regulatory and financial risk). As discussed in the previous section, Ontario's electric transmission and distribution utilities have similar deemed equity ratios as other electric utilities in Canada but substantially lower equity ratios than their U.S. counterparts. Ontario's gas distributors have somewhat lower deemed equity ratios than other gas distribution companies in Canada and substantially lower equity ratios than their U.S. peers. On that basis and as further discussed below, we find that these Ontario electric and gas utilities have higher financial risk than the North American proxy groups.

Credit metrics provide a snapshot of how a company is financed and to what extent fixed obligations absorb income and cash flows. Credit analysts focus on the potential for default on debt obligations and rate the financial strength of the companies they cover, with A range entities being more resilient and anything less than investment grade (i.e., BB+ or lower (for S&P Global, DBRS and Fitch), or Ba1 and lower (for Moody's)) being more volatile and higher risk.

Importantly, ratings agencies analyze the default risk for *debt holders,* and they consider equity as a cushion for debt, but they do not focus on the residual risk to the *equity shareholders*. Oftentimes, those risks are aligned at a macro level, but there have been notable cases where credit ratings have not been a good measure of shareholder risk. That is the case, for example, where a credit rating is supported at the expense of shareholders (e.g., through dividend restrictions), lowering risk to creditors but increasing risk to shareholders.[157]

Under the Fair Return Standard, the rate of return must be sufficient to enable regulated utilities to maintain financial soundness and to attract capital on reasonable terms. The utility industry is capital intensive, and companies require sufficient financial strength (i.e., sufficient equity) to access capital under a variety of economic and capital market conditions. An increase in the deemed equity ratio for Ontario's utilities is therefore necessary in order to bring the financial risk of Ontario's utilities more in line with their North American peers.

G. Sector Specific Risk Assessments

Utilities operating within each sector (electric distribution and transmission, natural gas distribution, electric generation) in the utility industry experience increasingly idiosyncratic challenges, which are considered by equity and debt investors in their capital allocation decisions. The risk profiles characteristic to each sector should be used in the evaluation of the cost of capital and capital structure to meet the Fair Return Standard across the industry.

1. Electric Distribution Utilities

Ontario electricity distributors' deemed capital structures are currently comprised of 40 percent

157 *See* Maritimes & Northeast Pipeline ("M&NP"), which had its A rating confirmed in April 2009 despite the fact that since November 2007, all cash distributions to equity owners were escrowed for the benefit of lenders. See DBRS, Maritimes & Northeast Pipeline Limited Partnership Report, April 9, 2009, where it states "Consequently, M&NP Canada's equity owners (77% Spectra Energy Corp, 13% Emera Inc. and 10% ExxonMobil Corporation (ExxonMobil)) have not received cash distributions since November 30, 2007. This will continue until cash balances have been built up to an amount sufficient to meet all remaining scheduled principal and interest payments on the M&NP Canada Notes until maturity in November 2019. DBRS notes that the conventional natural gas reserve outlook for the east coast of Canada has deteriorated since the Test was incorporated into the M&NP Canada financing documents in 1999. Consequently, the M&NP Canada noteholders have the benefit of this protection."

equity, 56 percent long-term debt, and 4 percent short-term debt. As further discussed below, the electricity distributors' equity ratios fall below those of their North American peers.

In the evolving environment of the Energy Transition and grid modernization, key risk factors for electric distribution utilities relate to forecasting, technological changes, performance expectations (both reliability and resilience), changing business models, and unanticipated capital expenditure risk. Growth of capital spending to meet increasing demand (such as that anticipated due to the Energy Transition) will put additional pressures on electric distributors' financial results and the perception of risk by both equity investors and credit rating agencies. A fair return on equity and reasonable deemed capital structure will ensure that distributors are able to attract equity and debt investment on reasonable terms amid growing capital needs to meet demand and improve resilience and reliability.

See Appendix B for a more detailed summary of business and financial risks related to this industry segment.

2. Electric Transmission Utilities

Ontario electricity transmitters' deemed capital structures are currently the same as electricity distributors (i.e., comprised of 40 percent equity, 56 percent long-term debt, and 4 percent short-term debt). As further discussed below, the electricity transmitters' equity ratios also fall below those of their North American peers.

Electric transmitter utilities' key risk factors relate to supply chain constraints, project development and permitting, the incurrence of large capital deferrals upon which only a debt return is accrued as a carrying charge under the current regulatory framework, operating across a large province with the potential for harsh weather conditions, and the forecasting of volumes. Increasing demand for electric transmission driven by customers and jurisdictional policy add pressure for transmission utilities not only to attract capital but also to compete for limited supply chain resources for project construction.

Transmission assets involve a lengthy timeline from conception to operation and are vulnerable to unforeseen cost and time overruns that may not be in the utilities' control. Wildfires and other unforeseeable circumstances (e.g., the COVID-19 pandemic) have impacted utilities' abilities to meet target timelines and project budgets. Moreover, we are aware of recent proceedings where intervenors have opposed full recovery of costs incurred by a transmitter required to continue construction of transmission assets during unforeseeable circumstances (e.g., COVID-19) resulting in a settlement reflecting a material reduction in recoverable costs.[158] Such precedents increase the perception of future risk for investors as they evaluate return requirements on future investments.

See Appendix B for a more detailed summary of business and financial risks related to this industry segment.

3. Electric Generation Utilities

OPG is the only regulated electric generation company in Ontario and the only pure-play generation utility in North America. OPG has a deemed equity ratio of 45%.

Given OPG's status, it is not possible to find companies that are exact comparators for OPG in terms of business and financial risk. OPG's regulated business operates a mix of hydro and nuclear generation facilities that provide approximately one-half of the Province of Ontario's generation supply.

In addition to being exposed to significant volumetric revenue risk and plant operating risk, key risk factors facing OPG relate to large capital investments and complex generation plant projects that are being undertaken to meet Energy Transition-related electricity demand and support climate-related government policy objectives over the next several decades. These projects include the completion of the Darlington Refurbishment Project, the planned refurbishment of four reactors at the Pickering Nuclear Generating Station, investments in Darlington SMRs, and several large hydroelectric refurbishment programs. At least in the near term, OPG is expected to undertake these projects while facing increased operating and revenue concentration risk within its nuclear operations, which would consist solely of the Darlington Nuclear Generating Station while the Pickering reactors are shut down and the Darlington SMRs are under construction. OPG's financial risk is also heightened due to the fact that large capital expenditures accrue a debt-only return as a carrying charge during

---

[158] For example, in EB-2023-0298, "intervenors were not in agreement with UCT 2 on the appropriateness of how [the COVID-19 productivity loss] amounts were determined and if there should be full rate recovery." This disagreement resulted in a settlement process that reduced UCT-2's recoverable COVID-19 productivity losses by $30 million.

construction under the current regulatory framework, and from heighted competition and constraints related to specialized supply chain and labour resources.

OPG's unique business model and higher-risk, first-of-a-kind investments increase the utility's overall risk profile relative to its transmission and distribution utility peers and require higher returns to attract sufficient capital. They also place OPG in a class by itself, whereby not only is its equity ratio lower than North American vertically-integrated utilities (which also have transmission and distribution operations), but also the peer groups used to establish the ROE understate returns for riskier generation-only operations. These factors are further amplified by the advent of the Energy Transition, whereby the company is increasingly focused on, and requires significant capital for, new generation development. For those reasons, Concentric is also recommending that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied as part of OPG's authorized ROE, the OEB consider that proposal at its discretion at that point in time.[159] As outlined in Section III, the approach to distinguishing risk by adjusting equity ratio and ROE has been adopted in British Columbia and Quebec to ensure relative risk across peers is properly reflected and this is essentially the approach Concentric recommends for OPG.

See Appendix B for a more detailed summary of business and financial risks related to this industry segment.

4. Gas Distribution Utilities

Enbridge Gas's capital structure is comprised of 38 percent equity and 62 percent debt. Like Ontario's other utility segments, Enbridge Gas's equity ratio falls below those of its North American peers, even with the increase in equity ratio authorized by the Board in 2023.

Natural gas distributors are facing increased operational and business risk, primarily due to the challenges and uncertainties in their business models amid the Energy Transition. Alternative gas suppliers and increased competition from electricity (i.e., the Energy Transition) have combined to increase the natural gas distributors' volumetric risk, while increased complexities of project permitting, execution, and cost recovery create new challenges that depend on supportive regulation by the OEB and active management of changing asset life cycles through depreciation practices. From

159 EB-2009-0084 Report of the Board, p. 13.

a financial perspective, as volume sales decline, natural gas distributors will see a decline in their credit metrics and financial positions. Declining financial positions will further heighten the risk for natural gas distributors and their current and potential investors. For example, S&P Global has already changed its target credit metrics for at least one U.S. gas utility due to increased exposure to Energy Transition risks. In May 2023, S&P Global revised the standalone FFO-to-debt threshold for SoCalGas, below which it would consider downgrading SoCalGas' credit rating, from 18 percent to 20 percent, stating that, "…because of California's ongoing energy transition that we view as a gradually increasing risk over the long-term, we now assess SoCalGas' business risk as more towards the middle of the range for its business risk profile category, compared to peers. We reflect this higher business risk by raising SoCalGas' downgrade threshold".[160]

Higher risks associated with elevated operational and business challenges in the short-term by experimentation with and adoption of alternative fuels to longer-term uncertainty regarding business viability, will require higher returns from investors. Support from regulators in their authorized cost of capital and equity thickness will ameliorate some of the current financial risks faced by natural gas distributors and will provide investors and rating agencies assurance that heightened risk is properly accounted for in equity and debt instruments.

See Appendix B for a more detailed summary of business and financial risks related to this industry segment.

H. Conclusion on Utility Risk Profiles and Risk Ranking

Historically, the Board's risk ranking of Ontario utilities places Enbridge Gas at the low end of the risk spectrum and OPG at the high end, with electricity distributors and transmitters in the middle. Based on industry-segment-specific risks, and, in particular the acute risks to the natural gas distribution segment caused by the Energy Transition, Concentric finds natural gas distribution to be riskier than electric distribution operations. In addition, Concentric views single-asset transmission utilities as bearing distinct risks related to a lack of diversification that warrant a higher equity ratio than multi-asset transmitters. Concentric further finds that OPG, as the only regulated pure-play generation company in North America, with significant planned investments in nuclear projects and significant

160 S&P Global, "Southern California Gas Co. Outlook Revised to Negative from Stable Reflecting Energy Transition Risk; Ratings Affirmed," May 12, 2023.

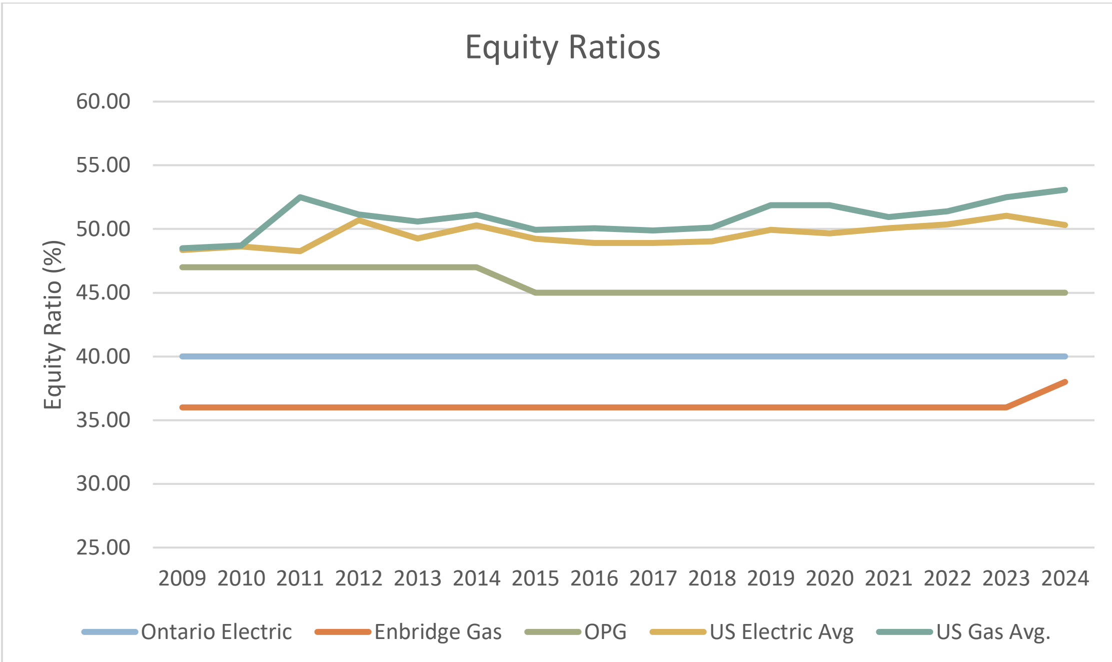
exposure to volumetric revenue risk, has a distinct risk profile that sets OPG apart from other Ontario utilities.

Independent of the risk ranking, however, Concentric is concerned that Ontario equity thicknesses, by being lower across the board than their U.S. peers, do not meet the Fair Return Standard. In the following sections, Concentric further discusses our recommendations regarding establishing equity thickness parameters in conjunction with the ROE in this proceeding that addresses that concern.

I. Analysis of Comparative Equity Ratios

The deemed equity ratios for Ontario's regulated electric distribution and transmission and gas distribution utilities are generally in line with the average equity ratios for their Canadian counterparts but well below the average level for U.S. electric and gas utilities. OPG has no direct peers, but it also falls below the average equity thickness levels for U.S. electric and gas utilities, despite its elevated level of risk. As shown in Figure 35 below, the deemed equity ratio for Ontario's electric distribution and transmission utilities of 40 percent is slightly lower than the Canadian average of 41 percent but substantially lower than the U.S. average of approximately 51 percent. The deemed equity ratio for OPG of 45 percent falls in between. Similarly, the deemed equity ratio for Enbridge Gas of 38 percent is slightly below the Canadian average of 39.9 percent (which includes the BCUC's recent increase to FortisBC Energy Inc.'s deemed equity ratio from 38.5 percent to 45.0 percent due primarily to risks associated with Energy Transition) and significantly lower than the U.S. average of slightly more than 52 percent. This gap in equity ratios with the U.S. means that Ontario's regulated utilities have substantially greater financial risk than their U.S. counterparts.

Figure 35: Deemed Equity Ratio in Ontario Compared to Canadian and US Averages – 2009-2024



Concentric also compared the deemed equity ratios for Ontario's electric and gas utilities to the actual and authorized equity ratio for the operating companies in the Canadian and U.S. proxy groups. The results of that analysis are summarized in Figure 36 below and shown in Exhibits CEA-10.1 through 10.6. This analysis demonstrates that the current deemed equity ratios are well below both the actual and authorized equity ratios for the operating utility companies in the U.S. Electric and U.S. Gas proxy groups. This is not consistent with the Fair Return Standard.

Figure 36: Actual and Deemed Equity Ratios for Proxy Groups

Proxy Group	Actual Equity Ratio	Deemed/Authorized Equity Ratio
U.S. Electric	52.30%	52.12%
U.S. Gas	53.85%	54.55%
Canadian	52.70% (US subs) 43.40% (Canadian subs)	51.69% (US subs) 40.30% (Canadian subs)

In light of these findings, Concentric recommends that the OEB's approach to setting the deemed capital structure should consider each particular utility company within the context of similarly-situated companies, for example, the proxy group companies, rather than being limited to requiring a demonstration of changes in business risk over time. Under the existing, latter approach, the OEB does not avail itself of all the necessary evidence to assess how the deemed capital structure for Ontario's regulated utilities compares to how other utility companies with comparable risk are capitalized, which in our view is necessary to meet the Fair Return Standard.

J. Deemed Equity Ratio Recommendation for the Ontario Utilities

The Fair Return Standard requires the OEB to set a return that (1) is sufficient for the utilities to maintain their financial integrity, (2) allows the utilities to attract equity and debt capital on reasonable terms, and (3) enables the utilities to compete for capital by offering a comparable return as investments of similar risk. Ontario equity thicknesses do not currently adhere to that standard.

Based on our analysis, we find that Ontario's regulated distribution and transmission utilities generally have comparable business risk to the companies in the North American Electric and Gas comparator groups. We also conclude that Ontario's utilities have similar financial risk to other electric and gas utilities in Canada and substantially greater financial risk than their U.S. peers due to the relatively low deemed equity ratios of 38 percent for Enbridge Gas, 40 percent for electric distribution and electric transmission, and 45 percent for OPG.

Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist entirely of generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. OPG's business risk, however, is considered to be higher than the proxy groups presented herein.

Given these findings, Concentric recommends the following with regard to equity thickness:

1. In the context of this generic cost of capital proceeding, and with a finding by the OEB that Ontario's regulated utilities have comparable business risk to the North American Electric and Gas proxy groups, the deemed equity ratios in Ontario are low compared to North American peers and therefore do not meet the Fair Return Standard. Ideally, the Ontario utilities should have a deemed equity ratio at parity with their U.S. counterparts, which is approximately 50-51 percent for electric utilities and 52 percent for gas distributors. In recognition of the regulatory principle of gradualism, however, an immediate move to parity with the U.S. would be abrupt. For that reason, we recommend that the OEB set a minimum

deemed equity ratio for Ontario utilities of 45 percent, which is at a point approximately halfway between the Ontario level and the U.S. average. That equity ratio would reflect progress towards parity for equity thickness among North American peers. Increasing the equity ratios for electric distributors and transmitters and Enbridge Gas would also reflect those industry segments' increased levels of risk. We also recommend increasing OPG's equity ratio in order to meet the Fair Return Standard, with a specific determination to be made by the OEB as part of OPG's next payment amounts proceeding taking into account the company's higher business risk relative to the proxy group.

2. In this proceeding, Concentric is not recommending individual utility changes to equity thickness. As discussed herein, there are factors that differentiate the risk levels among multiple segments of the industry, including OPG, single-asset transmitters, and Enbridge Gas As such, in addition to our recommendation of a minimum 45 percent equity ratio, we also recommend that each utility be authorized at its discretion to retain its current equity ratio and also have the ability to propose differences from the "generic" equity thickness in its rates application.

LEI's Recommendation and Concentric's Response

LEI recommends maintaining the OEB's current approach to determining the cost of capital, including the deemed capital structure, as, in LEI's view, it sufficiently considers investors' perspectives, i.e., the allowed cost is commensurate with the perceived risks associated with the sector, and meets the Fair Return Standard. LEI also recommends modification of interim reporting requirements to facilitate OEB's ongoing review of the utilities' cost of capital.

In Concentric's view, resetting the appropriate cost of capital and deemed equity thickness based on the methodologies described herein (i.e., DCF, CAPM, and Risk Premium models), along with consideration of financial, regulatory, and policy risks and an analysis of peer company equity ratios would ensure that the Fair Return Standard is met. The Fair Return Standard requires consideration of both changes in the utility's risk profile over time, as well as how the utility's business risk and deemed capital structure compares to the proxy group companies. Furthermore, commensurate returns and equity thickness set for the duration of the rate term, and reviewed every five years by the OEB, support relative regulatory predictability and the utility's financial stability.

Concentric does not support LEI's recommendation to modify annual reporting to include results of recent credit and equity issuances as this information would be retrospective for the prior year. Independently, these reports would not provide sufficient indication of future costs of capital or business risks on the horizon. Per the status quo, any utility facing a significant change requiring a re-evaluation by the OEB would provide evidence in its next rates application in which they would present the supporting evidence.

In Concentric's view, the OEB should rebase the authorized return on equity for Ontario's utilities based on current market data and set the deemed equity thickness for Ontario's utilities to better reflect the capital structure and business risk of Ontario utilities relative to the North American proxy group companies.

LEI's recommendation for utilities to include forward cash flow modeling and scenario analysis showing the impact on credit metrics to support significant changes in business and/or financial risks creates a methodology that is too rigid and limiting for supporting changes that may need custom approaches in the future, and also raises confidentiality concerns. Reliance solely on cash flow and its impact on credit metrics fails to incorporate the complexity and manner of risks considered by equity investors, especially in an evolving risk environment. It also does not consider the utility's competitiveness for capital relative to its peers.

K. Single Asset 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 risk analysis provided in the prior sections is based on corporate entities holding multiple assets. In this proceeding, Concentric is not providing specific recommendations regarding differences in equity ratios for each utility, but rather is focused on a "generic" equity thickness that can then be modified in individual utility rates applications, as is currently permitted in Chapter 2.9 of the Filing Requirements For Electricity Transmission Applications.

In such a rates application, we expect that factors related to diversification of operations would be considered, among others. For example, Concentric notes that single-asset companies do not have the same benefits of ongoing cash flows from other operations and the associated diversification of revenues, which can contribute to their risk profile.

In the specific case of electric transmission, development of these projects from concept to commercial service often takes a decade or longer. Development risks, however, are borne by transmitters more generally, regardless of whether they own a single or multiple assets. As a general matter, however, and focusing on those assets under OEB regulation, single-asset owners lack diversification.

A recent example is the East-West Tie built by NextBridge, a partnership among NextEra Energy Transmission Canada, Enbridge, OMERS Infrastructure and Bamkushwada. The project was placed into service in March 2022, from a competitive solicitation initiated by the Ministry of Energy in 2011.

The development process for transmission lines incorporates a series of steps (and risks) encompassing design, engineering, routing, permitting, financing, contracting, construction management, and regulatory approvals. In Ontario, all entities, including single asset developers, incur costs over the course of development without an equity return or cash flow until approved into Ontario's Uniform Transmission Rates ("UTRs").

In the U.S., FERC explicitly recognizes the challenges and risks of electric transmission development and approves certain incentives designed to promote development that ensures reliability or reduces the cost of delivered power. These incentives include:

1. Regulatory Asset Incentive - recovery of prudently incurred pre-commercial costs not capitalized and authorization to accrue carrying charges and amortize the regulatory asset;

2. Abandoned Plant Incentive - recovery of 100 percent of the prudently incurred costs in the event that a project must be abandoned for reasons outside of the developer's control;

3. Hypothetical Capital Structure Incentive - use of a hypothetical capital structure (typically consisting of 50 percent debt and 50 percent equity, but some projects have equity ratios of 60% or higher) until the project achieves commercial operation;

4. RTO Participation Adder - inclusion of a 50 basis point adder to its base ROE for Regional Transmission Organization ("RTO") participation.

Consideration of a similar set of incentives in Ontario exceeds the scope of issues raised by the Board in this proceeding, but the use of a deemed capital structure better reflecting how these projects are financed would be an appropriate step. As a practical matter, independently developed transmission projects require 100 percent equity during the early stages of development and shift to a mix of equity and debt financing as the project matures into construction through commercial operation. The use of such a deemed capital structure is recognized by FERC for the benefit of raising capital during the construction phase and maintaining low debt costs while actual debt-to-equity ratios vary.[161]

DBRS characterizes these risks in its credit rating for the East-West Tie project:

> *Credit Rating Rationale: East-West Tie's credit ratings are supported by its low business risk and the supportive regulatory environment. This is partly offset by its refinancing risk, weaker cash flow-to-debt metric, limited access to equity markets, and reliance on a single transmission line for its revenues and cash flows.*[162]

Concentric recommends that the Board adopt a minimum equity ratio of 45% for all electric transmitters, and we have not made specific recommendations at this time regarding any risk premium that may be warranted for single-asset transmitters. Such a differential could be proposed and supported in the context of utility-specific rates applications.

LEI's Recommendation and Concentric's Response

LEI recommends maintaining the OEB's current approach to determining the cost of capital for all electric transmitters, based on its view:

> *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.*

And:

161 See: DCR Transmission, LLC, 153 FERC ¶ 61,295 (2015) p. 45–46.

162 Morningstar/DBRS, Morningstar DBRS Confirms East-West Tie's Ratings at A (low) with Stable Trends, May 1, 2024.

> *Moreover, size is less of an issue for Ontario's electricity transmitters as transmitters have essentially one customer: IESO. Variations in OM&A expenses are likely minor, and efficiencies can be achieved through contracting out. Transmitters (big and small) cannot diversify customer risk or economic risk but are likely insulated from volume risk based on their tariff structure. Many licensed transmitters are also part of larger entities (for example, B2M Limited Partnership and Hydro One Sault Ste. Marie LP are subsidiaries of Hydro One; Canadian Niagara Power Inc. is a subsidiary of Fortis Inc.). Further, similar to electricity distributors, allowing higher equity thickness for smaller transmitters may discourage the consolidation of smaller entities. (LEI Report, p. 143-144)*

LEI's view does not consider the unique risks of transmission development, and the extent to which they are proportionately greater for a single-asset developer lacking the diversity of revenues and cash flows of a diversified transmission (or T&D) owner in Ontario. Reliance on one customer, the IESO, if anything increases risk, as IESO's rules are subject to operational and government policy changes not found in a broader customer mix. A foundational business management principle is the avoidance of a high customer concentration, let alone a single counterparty. As LEI recognizes "Transmitters (big and small) cannot diversify customer risk or economic risk." The fact that transmitters may be part of larger entities does not reduce the risk of the single asset investment in Ontario if that entity is established on a stand-alone basis for purposes of raising capital. This is not a size issue; it is a matter of diversifiable business risk, which a single asset transmitter does not possess.

VIII. MECHANICS OF IMPLEMENTATION

The OEB has asked parties to address several issues pertaining to implementation and monitoring of a formula:

> **In Issue #14, the Board asks:** 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?

As noted, all formulaic approaches run the risk of deviation from a fair return. Fluctuations in financial markets are inevitable, and relationships between bond and utility equity securities cannot be fully anticipated by historical relationships, leading formulaic automatic adjustment mechanism results to deviate from required equity returns. Consequently, periodic rate hearings remain the only reliable method for determination of utility ROEs that remain consistent with the Fair Return Standard. Understanding this limitation, Concentric recommends the Board take several steps to limit the potential impacts of deviations between the formula ROE, deemed capital structures and a fair return. Given that short and long term debt rates are linked to market based data, those rates should be self-regulating. ROE and capital structure should therefore be the primary focus.

Concentric recommends the OEB track and compare the following key utility and broader macroeconomic parameters:

- Authorized ROEs and equity ratios in other Canadian jurisdictions (individually) and the U.S. by industry segment (electric, gas) as reported by RRA
- 10 and 30-year Treasury Bond Yields (Canada and the U.S.)
- A- and BBB-Rated Utility Bond Yields (Canada and the U.S.)
- Betas for the North American Proxy Group as defined in Section V

This comparison should be done on an annual basis.

LEI's Recommendation and Concentric's Response

LEI recommends maintaining the OEB's existing approach: "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." (LEI Report, p. 148)

Concentric does not object to a quarterly report but is of the view that an annual update that consider the above noted macroeconomic parameters is sufficient for these purposes. We do not see any basis for restricting the monitoring to an internal report. Sharing of such information increases transparency and would allow stakeholders the opportunity to monitor the results of the OEB's cost of capital determinations on the same basis as Staff.

> **Issue #15, the Board asks:** 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?

We address the three components to the Board's question: How should the OEB regularly confirm that:

(1) The FRS continues to be met?

Concentric's ROE and capital structure recommendations outlined in Sections VI and VII are based on a full evaluation of capital market information necessary to meet the standards of the FRS. These recommendations should be adopted so that the base ROE and deemed capital structures meet the FRS at the outset. Thereafter, Concentric's monitoring recommendations outlined in response to Issue #14 should be sufficient to detect any material deviations from the FRS over the period between full reviews (e.g., every 5 years).

(2) Rate-regulated entities are financially viable?

Financial viability is a lower threshold than meeting the FRS, and might be interpreted as the ability to raise debt sufficient to fund ongoing operations and meet debt obligations, at least in the near-term. Credit rating agencies focus on these issues and underlying financial metrics, so in addition to the monitoring outlined in Issue #14, Concentric recommends monitoring:

- Credit ratings from each agency covering Ontario's rate-regulated utilities.

(3) Rate-regulated entities have the opportunity to earn a fair, but not excessive, return?

There are two dimensions to this issue. First, the fair return begins with setting the authorized ROE and deemed equity ratios established under the FRS, as recommended by Concentric in previous sections. Second, the opportunity to earn that return is based on a combination of efficiency of management, fluctuations in customer demands and macroeconomic or operational events beyond the utility's control, and the regulatory framework. Excessive (or insufficient) returns can be prevented through a combination of earnings sharing mechanisms and/or offramps tied to the allowed ROE. The OEB's existing policy for electric distributors, in Concentric's view, is reasonable, where "Each rate-setting method will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated."[163]

- Concentric recommends a continuation of this 300 bp trigger mechanism policy for all rate-regulated utilities.

LEI's Recommendation and Concentric's Response

LEI recommends:

> *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 can 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 the FRS continues to be met.* (LEI Report, p. 151)

Concentric agrees with LEI that annual monitoring of the FRS is sufficient (although this does not require quarterly reporting, as recommended by LEI under Issue #14). We are in further

163 Renewed Regulatory Framework for Electricity, Report of the Ontario Energy Board, October 18, 2012, p. 11.

agreement on requiring utilities to file updates to their credit ratings on an annual basis. We do not, however, see the benefit of requiring utilities to file specific details regarding equity and debt issuances during each year. This would be both administratively burdensome, and beyond typical reporting requirements.

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?

Under the provisions adopted in the 2009 Report, the OEB typically updates its cost of capital parameters annually in October or November for rates effective January 1 of the following year. From 2010 through 2013, the Board also updated its parameters in February or March for rates effective May 1, but has since discontinued this practice, although many distributors still have a May 1 rate year.

Figure 37: OEB Cost of Capital Parameter Updates

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

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

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

LEI's Recommendation and Concentric's Response

LEI recommends:

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

Consistent with Concentric's recommended changes to the formula inputs, as outlined under Issue #10, we are in agreement with LEI on the annual updates to the OEB's cost of capital parameters in October, using data as of September 30th, except where forecasts are utilized. Concentric generally recommends trailing 90-day averages where historic data are utilized to avoid the inherent volatility in a single month's data.

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?

As previously noted, all formulaic approaches run the risk of deviation from a fair return. Fluctuations in financial markets are inevitable, and relationships between bond and utility equity securities cannot be fully anticipated by historical relationships, leading formulaic results to deviate from required equity returns. Consequently, periodic rate hearings remain the only reliable method for determination of utility ROEs. Understanding this limitation and adopting the monitoring steps recommended in response to Issues #14 and #15, Concentric recommends periodic cost of capital reviews with refreshed market data on ROE and capital structure every five years.

Taken together, these steps provide a reasonable balance between the regulatory efficiency of a formulaic based approach and the requirements of meeting the Fair Return Standard. An additional safeguard would be to adopt the FERC approach, allowing the Board or an intervenor to challenge the reasonableness of the allowed return (including both the ROE and capital structure), or for a company to request a change in its authorized return, based on updated market evidence.

LEI's Recommendation and Concentric's Response

LEI recommends:

> *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 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.* (LEI Report, p. 158)

Concentric and LEI are in agreement on this issue.

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)?

Changes in the cost of capital parameters (ROE, long-term debt and short-term debt rates) should take effect for all utilities in the rate year following the OEB's decision in this proceeding (subject to any settlement agreements and each utility submitting a compliance filing demonstrating how the change would be implemented within the context of its specific IR plan), and in subsequent periods where the parameters are updated. This is especially important given the passage of time since the Board's last full review in 2009. In Concentric's view, it is not necessary to wait for rebasing, and any delays in implementation would not serve the public interest or meet the Fair Return Standard if the Board determines that updated parameters are justified.

Depending on the magnitude of change in the deemed capital structure, the Board may want to consider changes in capital structure implemented over a period of up to three years. This incremental approach would serve two purposes: 1) to allow the utility treasury functions to manage the transition (e.g., retiring debt and investing new equity as appropriate), and 2) to mitigate the effects of any rate impacts. Unlike ROE and debt rates, changes in the capital structure can require time to implement.

LEI's Recommendation and Concentric's Response

LEI recommends:

> *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.* (LEI Report, p. 160)

Concentric disagrees that changes in the cost of capital should be only implemented on rebasing. Ontario's utilities operate under rate programs with durations extending for up to 5 years or longer. There is no reasonable interpretation of the FRS that would allow such a time lapse in meeting the return standard if the OEB determines that such changes are warranted. Concentric recommends that the ROEs for all utilities be updated and rebased according to our recommendations at the start of the next rate year for each utility. Depending on the magnitude of change in the deemed capital structure, the Board may want to consider changes in capital structure implemented over a period of up to three years.

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?

Yes, as indicated in response to Issue #18, Concentric believes it would be appropriate for changes in the cost of capital parameters and/or capital structure arising from this proceeding to be implemented in the next rate year, including for utilities in an approved rate term, subject to any settlement agreements and each utility submitting a compliance filing demonstrating how the change will be implemented within the context of its specific IR plan (e.g., Custom IR or I-X plan). All other elements and incentives of existing rate plans would remain in effect.

LEI's Recommendation and Concentric's Response

LEI recommends:

> *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).* (LEI Report, p. 163)

LEI recognizes that the cost of capital parameters resulting from this proceeding must meet the FRS. "LEI believes the OEB's current approach of implementing cost of capital parameter and capital structure updates upon rebasing remains appropriate, so long as implementation of these changes in this way continues to meet the FRS and does not directly result in rate shock." On this point we agree, but we see no basis for the limitations recommended in LEI's two-prong test, or a determination of "rate shock". The FRS has no provision for "rate shock", or a 100 basis point differential. The cost of capital is a true cost that should be recognized in customer rates as soon as reasonably possible. Changes in the cost of capital parameters and/or capital structure should be implemented in the next rate year, including for utilities in an approved rate term, unless the Board and utility agree to a gradual implementation in changes in capital structure. (LEI Report, p. 161-162*)*

IX. OTHER ISSUES

The OEB has asked parties to address two other issues in their submissions, as outlined below:

> **Issue #20:** Prescribed Interest Rates - Should the prescribed interest rates applicable to DVAs and the CWIP account for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be calculated using the current approach?[164]
>
> **Issue #21:** If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?
>
> **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?[165]

Concentric addresses these issues, and LEI's recommendations, in the discussion that follows.

A. Prescribed Interest Rates and Carrying Costs on CWIP

The OEB applies a formulaic approach to setting prescribed interest rates for DVAs and CWIP, although DVAs have a different interest rate than CWIP. For DVAs, the OEB applies the 3-month bankers' acceptance rate plus a fixed spread of 25 basis points. For CWIP, the OEB applies the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate yield.

Concentric's view is that the approach to determining the appropriate carrying costs to apply to DVAs and CWIP should be based on regulatory and corporate finance principles. As described below, the application of the WACC to both DVAs and CWIP is most consistent with those principles.

At the most fundamental level, the appropriate carrying cost on DVAs should reflect the cost of capital associated with the delay in recovery. DVAs and other regulatory deferrals are common tools that allow a smoothing out of the rate impacts of extraordinary or unanticipated expenditures. Regulators typically apply long-standing regulatory and corporate finance principles in determining the carrying

---

164 OEB website; EB-2006-0117, OEB Letter, Approval of Accounting Interest Rates Methodology for Regulatory Accounts November 28, 2006; Accounting Procedures Handbook For Electricity Distributors, Issued: December 2011, Effective: January 1, 2012, Article 220, p. 200; Article 410, pp. 27 & 28.

165 Please refer to the OEB's Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs, issued November 2, 2023.

cost. Those principles support the conclusion that the WACC appropriately reflects the appropriate remuneration for regulated utilities that must finance investments and operations.

Utilities must fund day-to-day operations, and they also invest in a mix of long-term assets (such as property, plant, and equipment) and short-term assets (such as net working capital). From a corporate finance perspective, financing sources are commonly matched in duration to the service lives of the underlying assets, so that repayment obligations are matched to the income produced by the assets. In practice, however, it is not feasible to trace one source of financing (e.g., long-term or short-term debt) to individual assets. Rather, the utility's overall capital structure (comprised of various financing sources and durations) supports its overall asset base (comprised of assets of various lives). As noted by Brigham and Houston:

> *In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term assets from short-term sources and long-term assets from long-term sources.*[166]

In addition, while utilities may use short-term debt to finance immediate needs such as capital expenditures or working capital needs, they will also refinance those borrowings with long-term financing as practical and as market circumstances afford.

As discussed previously, the applicable regulatory standard with regard to the carrying cost on regulatory assets is the Fair Return Standard.

The principle of a fair return applies to DVAs because utilities have committed capital to fund their deferred costs, and that commitment of capital warrants the opportunity to earn a reasonable return. For utilities to have the opportunity to earn a reasonable return, they must have the opportunity to recover the WACC. Just as each utility's assets are comprised of a mix of shorter- and longer-term assets, so too do its financing resources reflect a mix of shorter- and longer-term sources. To draw a line that traces one source of financing to one asset for purposes of establishing the return on DVAs would be inconsistent with the application of a WACC return to each utility's overall rate base. For instance, if we assume that one source of financing, such as a specific issuance of debt, is used to fund one element of a company's operations, then, in order for the company to maintain its capital

[166] Brigham, Eugene F. and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, p. 574.

structure, we must assume that a separate element of the company's operations is funded by a different source or issuance. Such an approach is not practicable or, in many cases, even feasible. As noted by Professor James Bonbright, a widely recognized regulatory theorist and economist:

> *Rate base is defined as the: (1) net plant in service; (2) property held for future use; (3) working capital; and (4) construction work in progress (CWIP) – no AFUDC. The capital structure simply represents the funds used to finance the rate base.* ***The sources, not the uses, of funds (debt, equity, deferred taxes, and other capital structure components) are not easily traceable.***[167]

Concentric recognizes that the timeframe over which a regulatory asset is accumulated and recovered is a historical consideration by the Board in assigning an appropriate carrying cost. At the same time, as described above, it is not practicable to trace one source of financing (e.g., long-term or short-term debt) to individual assets. In addition, disregarding the WACC for certain financings but applying it for others would double-count certain debt issuances in the cost of capital and undermine the overall regulatory financing assumptions upon which rates are determined and investors are compensated.

Concentric recommends, for the reasons discussed above, that the Board apply the WACC to DVA balances that are to remain on utilities' balance sheets for more than one year and retain a short-term rate for DVAs that are cleared within one year.[168] As symmetry is an important consideration, Concentric recommends the short-term rate or WACC (depending on the timeframe of the DVA's disposition) be applied to both positive and negative DVAs. Application of the WACC to long-term DVAs would be consistent with the BCUC's approach, as discussed by LEI.

In terms of CWIP, Concentric finds that the current approach that applies the long-term cost of debt to CWIP balances has the potential to significantly understate the cost of capital for utilities during the construction phase of projects. While certain smaller and more routine construction projects can be completed within a year, many are larger, long-term projects, and the period between when construction costs are first incurred and when those assets go into service can span multiple years. Over those periods, the utilities are financing construction on their balance sheets at the WACC,

167 Bonbright, Danielsen, & Kamerschen, Principles of Public Utility Rates, Second Edition, Public Utilities Reports, Inc. p. 237.

168 DVAs that clear within one year would be those that are disposed within 12 months of the deferral of costs.

which includes an equity component. The OEB's current approach to carrying charges on CWIP recognizes the long-term nature of construction projects by applying a long-term cost of debt, but ignores that utilities also employ retained earnings and equity issuances to fund construction. Excluding the cost of equity borne by utilities during construction deprives the utilities of the opportunity to recover their full costs of financing, including the cost of equity over the life of the investment.

Furthermore, a long-term debt-only approach also places the Ontario utilities out of step with their U.S. and Canadian peers, placing them at a relative disadvantage in the ability to attract equity capital, which can be of particular concern during the Energy Transition.

For example, the FERC formula for accruals of carrying charges on CWIP includes an equity component. The formula (referred to by FERC and herein as "Allowance for Funds Used During Construction," or "AFUDC") is provided below:

Figure 38: FERC AFUDC Formula[169]

$A_i = s(S/W) + d(D/D + P + C)(1-S/W)$

$A_e = [1-S/W][p(P/D+P+C)+c(C/D+P+C)]$

> A_i = Gross allowance for borrowed funds used during construction rate.
> A_e = Allowance for other funds used during construction rate.
> S = Average short-term debt.
> s = Short-term debt interest rate.
> D = Long-term debt.
> d = Long-term debt interest rate.
> P = Preferred stock.
> p = Preferred stock cost rate.
> C = Common equity.
> c = Common equity cost rate.
> W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs (See General Instruction 25) related to plant under construction.

As shown above, the FERC approach first assumes that construction is funded with short-term debt. Then, after the balance of short-term debt is applied, FERC assumes the remainder of CWIP is financed on the utility's balance sheet at its WACC. LEI did not provide a jurisdictional survey of the approach to calculating carrying charges on CWIP in other jurisdictions, but, in Concentric's

169 FERC Uniform System of Accounts (18 CFR Part 101), accessed July 10, 2024.

experience, the FERC formula is used both by FERC-jurisdictional utilities as well as widely by regulators at the state level.

Many Canadian regulators also allow the accrual of AFUDC at the WACC as well. For example, British Columbia, Newfoundland and Labrador, Canada Energy Regulator, the AUC and Nova Scotia allow utilities to accrue carrying charges on CWIP at the WACC.[170] In fact, use of a debt-return only makes Ontario an outlier among North American regulatory jurisdictions, as described below. Concentric believes this approach would not be overly burdensome as each utility would be responsible for performing the calculation based on readily-available accounting data, and based further on that fact that it is so widely applied (and, generally, with little controversy), in the U.S. and other jurisdictions.

For the reasons outlined above, Concentric recommends that the OEB apply the WACC to CWIP for purposes of accruing carrying costs on construction balances. Since the OEB already considers short-term debt within the capital structure for many of the utility participants, the FERC specification of the AFUDC rate does not need to be specifically applied. Rather, the application of the WACC for Ontario utilities appropriately reflects the regulated capital structure, including short-term debt.

LEI's Recommendation and Concentric's Response

LEI recommends that, for DVAs, the OEB align the prescribed interest rates with LEI's proposal for the DSDTR, which is the average of 3-month CORRA futures rates for the next 12-month period plus the spread for a R1-low rated utility over CORRA, based on a confidential survey of 6-10 banks. For CWIP, LEI recommends continuing the current approach. In making these recommendations, LEI states that it is seeking to achieve the objectives of: (1) an internally-consistent cost of capital policy framework to align calculation methodologies where possible; and (2) consideration of previous OEB decisions. (LEI Report, p. 168)

Concentric agrees with LEI's recommendation for short-term DVAs (i.e., accounts that will clear within one year), but, as discussed above, recommends the Board apply each utility's WACC to long-term DVAs, consistent with corporate finance principles.

Concentric disagrees with LEI's recommendation regarding CWIP, as discussed above. Concentric rather recommends that the WACC be applied in order to provide for recovery of the utility's full

[170] See, e.g., Nova Scotia Power's "WACC and AFUDC Updates" application, November 30, 2016, p. 3-4; and FortisBC Inc.'s "Annual Review for 2023 Rates," August 5, 2022, p. 77.

financing cost, particularly given the need to attract significant capital in support of the Energy Transition. From an implementation perspective, this approach is not burdensome because the WACC for each utility is readily available.

B. Carrying Charges on the Cloud Computing Deferral Account

The OEB established a deferral account for incremental costs of cloud solution implementation that was effective December 1st, 2023, the disposition of which would be determined in utilities' next rates application proceeding.

The adoption of information technology ("IT") cloud services[171] and associated ratemaking and regulatory issues have risen in prominence in recent years in the regulated utility sector. Numerous industry organizations have highlighted the benefits of cloud computing and recognized current barriers to utility adoption of cloud services given traditional utility ratemaking approaches.[172] Cloud computing can provide many important and meaningful benefits for utilities and their customers. There is also an overall technology industry trend that on-premise versions of major platforms are being phased out. As such, Concentric believes it is important from a regulatory policy perspective that utilities are not disincentivized to pursue cloud computing solutions, and further that ensure that utility decisions consider the best operational outcomes (and therefore lowest long-term customer cost). Concentric finds that cloud solutions should be treated on par with in-house capitalized IT systems, appropriately removing the aforementioned disincentive. This is further warranted by the fact that DVAs more typically account for pass-through items or items that are beyond the control of the utility, while the Cloud Computing Deferral Account is differentiated

171 Terminology regarding "the cloud" varies somewhat in utility industry publications and documents. For example, a 2016 National Association of Regulatory Utility Commissioners ("NARUC") Resolution on capitalizing the cloud describes: "state-of-the-art commercial cloud computing services, which is increasingly delivered via a "cloud-based" or "software-as-a-service" ("SAAS") model." NARUC, "Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements," 2016 ("NARUC Resolution"), p. 1. A recent report developed for the Canadian Electricity Association ("CEA") and Canadian Gas Association ("CGA") notes, "'cloud' refers to cloud-based computing arrangements: the on-demand availability of computer system resources — especially data storage and computing power — without direct active management or ownership by the user." CEA, CGA, "Capitalizing the Cloud - An Analysis of Challenges and Opportunities for the Canadian Utilities Sector," KPMG, March 2020 ("CEA/CGA Report"), p. 2.

172 *See*, e.g., NARUC, "Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements," 2016 ("NARUC Resolution"), at 1; Electricity Canada, "Cloud Service in the Electricity Industry," May 22, 2024, p. 4.

because it involves utility choices, and thus the incentives behind those choices should be considered in setting the carrying cost rate.

LEI's Recommendation and Concentric's Response

LEI states that "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." (LEI Report, p. 175)

As discussed above, Concentric agrees with this recommendation.

X. CONCLUSIONS AND RECOMMENDATIONS

In response to the Issues raised by the Board, Concentric provides the following recommendations, as supported by the analysis and research provided in this Report.

Issue or Parameter	**Concentric Recommendation**
Base ROE	10.0% for all utilities; OPG may bring forward a proposal and present specific evidence as part of its payment amounts application regarding an additional risk premium applicable to its authorized ROE, for the OEB's consideration, at its discretion, as part of that separate proceeding
Equity Thickness	Minimum 45.0% for all utilities; OPG, Enbridge and Single-Asset Transmitters may present specific evidence in separate proceedings
Long Canada Bond Forecast Adjustment Factor	0.40
Utility Credit Spread Adjustment Factor	0.33
Issue #1: Should the approach to setting cost of capital parameters and capital structure differ depending on the source of capital (i.e., whether a utility finances its business through the capital markets or through government lending such as Infrastructure Ontario, municipal debt, etc.) or on different types of ownership (e.g., municipal, private, public, co-operative, not for profit, Indigenous / utility partnership?	In Concentric's view, it is consistent with both financial theory and regulatory practice to determine the cost of capital based on the *use* of funds and not the *source* of funds when determining just and reasonable rates. In addition, Concentric does not recommend that the approach to determining the authorized ROE or capital structure be differentiated by ownership type.
Issue #2: What risk factors (including, but not limited to, the energy transition) should be considered, and how should these risk factors under the current and forecasted economic and market conditions be considered in determining the cost of capital parameters and capital structure?	Risk factors that should be considered include business risk, including the Energy Transition, regulatory risks (encompassing regulatory lag, timely recovery of OpEx, fuel costs, and capital costs, volumetric risk, and others), and other business risks (including severe weather events, technology risks, and others), as well as financial risk (encompassing a utility's solvency, liquidity, and ability to attract capital and raise debt). Whenever possible, risk factors should be considered quantitatively with both current and projected values. Concentric recommends that utility-specific factors be focused on in determining whether a utility's equity thickness, in combination with the generic ROE, meets the Fair Return Standard. In addition, Concentric recommends that the OEB modify its approach to assessing utility risk to incorporate comparative risk and comparable return

	assessments, regardless of whether a significant change in risk has been demonstrated.
Issue #3: What regulatory and rate-setting mechanisms have impacted risk factors, and how should they be considered in determining the cost of capital parameters and capital structure?	A variety of mechanisms, including DVAs, should be included in the review of risk factors. Concentric recommends that the assessment of regulatory and rate-setting mechanisms should be based not only on the consideration of such mechanisms on an absolute basis, but also based on a comparison of Ontario's regulated utilities to the proxy group of companies used to determine the cost of equity. This is an important distinction that is necessary to meet the Fair Return Standard, as while the implementation of a new regulatory mechanism may reduce a utility's absolute risk, it does not necessarily reduce the cost of capital if peer utilities have similar risk-mitigating mechanisms available to them.
Issues #4 - #5: Should the Board continue to follow the same process for determining the cost of short-term debt as discussed in the 2009 Report? If no, how should it be set?	Concentric recommends the BA rate be transitioned to CORRA rates, and that the methodology be kept the same otherwise. Concentric disagrees with LEI's recommendation to apply a cap, as actual costs of borrowing can deviate from the deemed debt rate for reasons that are outside the control of the utility.
Issues #6 - #7: Should the Board continue to follow the same process for determining the cost long-term debt as discussed in the 2009 Report? If no, how should it be set?	Concentric finds that the general use of embedded debt costs of each individual utility company is reasonable and appropriate for previously-incurred debt, and further that utilities should be allowed to forecast debt rates for debt that will be incurred during the rate plan, subject to review and approval by the OEB. Concentric recommends transitioning from use of the C29530Y Index on Bloomberg to the BVCAUA30 BVLI Index for considering the spread over LCBF for an A-rated utility. We further recommend adopting the same approach we recommend to the ROE formula with reliance on bank forecasts for the 30-year bond yield versus the current approach that relies on the Consensus 10-year forecast plus a 10-30 spread. In either case, we recommend using 90-day averages for spreads versus the current month of September only. Concentric disagrees with LEI's recommendation to apply the deemed long-term debt rate as an automatic cap.

Issue #8: Should the Board allow Ontario's utilities to recover transaction costs associated with the issuance of long-term debt, consistent with the current approach that was adopted in the 2009 Report?	Debt issuance costs are a legitimate cost of funding the operations of the utilities and should be recovered in rates through the embedded cost of long-term debt, as is the OEB's current practice.
Issue #9: What are the implications of variances from the deemed capital structure (i.e., notional debt and equity) and how should those variances be considered in setting the cost of long-term debt?	Concentric recommends maintaining the status quo; i.e., for rate-setting purposes, the deemed capital structure should determine the debt and equity costs that are recovered in rates, and that Ontario's regulated utilities continue to be given the discretion to manage their actual capital structure.
Issue #10: What methodology should the OEB use to produce a return on equity that satisfies the Fair Return Standard?	Based on present-day market analysis, Concentric finds that the OEB's ROE formula currently is not producing an authorized ROE that meets the Fair Return Standard. Concentric recommends that the Board re-set the authorized ROE to 10.0 percent based on the results of the DCF, CAPM and Risk Premium models. Further, that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied as part of its authorized ROE, the OEB consider that proposal at its discretion as part of that proceeding. In addition, the Board should adopt a process whereby the ROE formula is reviewed against the results of generally-accepted financial models at least every five years to ensure that the return satisfies the legal requirements of the Fair Return Standard. Concentric also recommends that the LCBF be computed based on a weighted average of the projected 30-year GOC bond yield for the subsequent year as reported by RBC, TD Bank, and Scotia Bank (assigned 75% weight) and the current average 30-year GOC yield for the 90 days ending September 30 of each year (assigned 25% weight). Further, we recommend that the Board update the average credit spread between the 30-year GOC bond yield and the A-rated utility bond yield as of September 30, based on a 90-day average. Finally, the Board should update the LCBF adjustment factor from 0.50 to 0.40, and the utility credit spread adjustment factor from 0.50 to 0.33, based on empirical results produced by a multivariate regression between historical authorized ROEs, government bond yields and utility credit spreads.
Issue #11: Are the perspectives of debt and equity investors in the utility sector	Concentric identifies several key factors identified by debt and equity investors and credit ratings agencies

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? Issue #12: How should the capital structure be set for electricity transmitters, electricity distributors, natural gas utilities, and OPG to reflect the FRS?	relevant to the determination of the cost of capital. Among these are: • Industry segment risk profiles • Climate risk • Energy transition • Cyber security risk • Regulatory risk Concentric recommends that the OEB consider Ontario's utilities within the context of similarly-situated companies; for example, the proxy group companies. Based on our analysis, we find that Ontario's regulated distribution and transmission utilities generally have comparable business risk to the companies in the North American Electric and Gas comparator groups. As such, we recommend that the OEB set a minimum deemed equity ratio for Ontario utilities of 45 percent, which is at a point approximately halfway between the Ontario level and the U.S. average, in the interest of gradualism in rates.
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?	Concentric does not make specific recommendations at this time regarding a risk premium that may be warranted for single-asset transmitters. Such a differential should be supported in the context of utility-specific rates applications.
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?	Concentric recommends the OEB track and compare the following key utility and broader macroeconomic parameters on an annual basis: • Authorized ROEs and equity ratios in other Canadian jurisdictions (individually) and the U.S. by industry segment (electric, gas) as reported by RRA • 10 and 30-year Treasury Bond Yields (Canada and the U.S.) • A- and BBB-Rated Utility Bond Yields (Canada and the U.S.) • Betas for the North American Proxy Group as defined in Section V.
Issue #15: How should the OEB regularly confirm that the FRS continues to be met and that rate-regulated	Concentric's monitoring recommendations outlined in response to Issue #14 should be sufficient to detect any material deviations from the FRS over the period

entities are financially viable and have the opportunity to earn a fair, but not excessive, return?	between full reviews (e.g., every 5 years), given that the ROE is appropriately re-based in this proceeding. Concentric further recommends that the Board monitors credit ratings from each agency covering Ontario's rate-regulated utilities and that the 300 bp trigger mechanism policy for all rate-regulated utilities be continued.
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?	The current timing for updates, in Concentric's view, represents a reasonable balance between the currency of the market data and sufficient advance notice to the regulated utilities and customers of the pending change to the rate of return. Concentric further recommends trailing 90-day averages where historical data are utilized to avoid the inherent volatility in a single month's data.
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?	Concentric recommends periodic cost of capital reviews with refreshed market data on ROE and capital structure every five years. All formulaic approaches run the risk of deviation from a fair return. Fluctuations in financial markets are inevitable, and relationships between bond and utility equity securities cannot be fully anticipated by historical relationships. Consequently, periodic rate hearings remain the only reliable method for determination of utility ROEs.
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)?	Concentric recommends that the ROEs for all utilities be updated and rebased according to our recommendations at the start of the next rate year for each utility. Depending on the magnitude of change in the deemed capital structure, the Board may want to consider changes in capital structure implemented over a period of up to three years.
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?	Changes in the cost of capital parameters and/or capital structure should be implemented in the next rate year, including for utilities in an approved rate term. The only exception would be an incremental approach to implementing changes in capital structure if deemed in the public interest, or specific limitations based on existing settlement agreements.
Issue #20: Prescribed Interest Rates - Should the prescribed interest rates applicable to DVAs and the construction	The application of the weighted average cost of capital to both DVAs and CWIP is most consistent with corporate finance principles. Concentric recommends that the

work in progress (CWIP) account for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be calculated using the current approach? Issue #21: If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?	WACC be applied to both positive and negative DVA accounts in the interest of symmetry. Additionally, understanding the Board's historical preference to apply a short-term interest rate to DVAs, as a practical matter, Concentric recommends that for DVAs that are to be cleared within one year, the short-term prescribed interest rate continue to apply.
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?	Concentric recommends that the WACC apply to Cloud Computing deferral account carrying costs, in order to incentivize utilities to invest in beneficial cloud computing technologies.

APPENDIX A: INDUSTRY SEGMENT EQUITY THICKNESS HISTORY

Natural Gas Distributors

In 1997, the Board published guidelines for its cost of capital methodology for gas distribution utilities. The Board's guidelines assumed that the base capital structure for gas distribution utilities will remain constant over time, but a full reassessment of a company's capital structure will be undertaken if there are significant adjustments to the company's business or financial risk.[173]

In 2006, Enbridge Gas Distribution Inc. ("EGDI") requested to increase its allowed equity thickness from 35 percent, which was set in 1993, to 38 percent to restore financial integrity and enable reasonable access to capital. During the proceeding, the Board noted the Canadian regulatory trend of allowing increases to the equity thickness for utilities.

The OEB allowed EDGI an equity percentage increase of one percentage point equal to 36 percent. The decision for EDGI was bound by a negotiated settlement for Union Gas, in which the Board allowed Union Gas an equity thickness of 36 percent. Union Gas was perceived to have greater business risk than EGDI, but the Board determined it was reasonable to allow the same equity thickness for Union Gas and EDGI.

In 2011, the Board found that EDGI's and Union Gas's deemed equity ratio of 36 percent continued to be appropriate. In its Decision and Order, the Board upheld its policy that for natural gas utilities, deemed capital structure is determined on a case-by-case basis, and that the evaluation of a gas utility's capital structure will only occur in the case of undeniable changes in the utility's business or financial risk.[174]

In 2017, Enbridge Gas Distribution's corporate parent, Enbridge Inc., merged with Union Gas's corporate parent, Spectra Energy Corp. The Board approved Enbridge Gas's application in 2017 to maintain the equity ratio of the amalgamated entity at 36 percent.

EPCOR Natural Gas has an approved 40% equity ratio.[175]

---

173 OEB, Draft Guidelines on a Formula-Based Return on Common Equity For Regulated Utilities (March 1997) p. 30.
174 EB-2011-0210, Decision and Order, p. 48.
175 OEB Staff Report, January 14, 2016, Table 1.

APPENDIX A: INDUSTRY SEGMENT EQUITY THICKNESS HISTORY

In 2023, Enbridge Gas requested an increase in its deemed equity thickness to 42 percent, claiming that the energy transition had increased the company's business risk. The Board ultimately approved an increase of two percentage points equal to 38 percent, finding that the energy transition increased Enbridge Gas's business risk, but the amalgamation offset a portion of the risk.[176]

Electric Distribution

The OEB did not have responsibility for regulating municipal electric utilities ("MEU") before the passage of the Energy Competition Act. After the Energy Competition Act was passed in 1998, the OEB was required to regulate more than 270 municipal electric utilities that existed at the time. The Board commissioned a research paper to analyze the appropriate equity thickness and cost of capital for Ontario's regulated utilities. The Board created a formulaic risk premium approach to the ROE and established a hypothetical "deemed" capital structure that varied based on the size of each utility.

The research paper evaluated six potential factors for categorizing risk for regulated electric utilities: i) size of operations, assets, and rate base; ii) the nature and stability of the municipal electric utility's customer mix; iii) the degree of competition from other fuels; iv) the age and condition of the physical distribution system; v) local climate peculiarities; vi) the geographic size and isolation of the service area; and vii) the availability of back up self-generation capacity.[177] The size of rate base alone was ultimately determined to be the most appropriate metric to categorize relevant risk for MEUs.[178]

Figure 39: OEB Research Paper – Municipal Electric Utility Risk Category[179]

Risk Category	Rate Base
Low	≥ $1 billion
Medium/Low	$300 million - $1 billion
Medium	$100 million - $300 million
Medium/High	$40 million - $100 million
High	≤ $40 million

176 Decision and Order. EB-2022-0200. December 21, 2023.

177 Dr. William T. Cannon, A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities in Ontario, Prepared for the Ontario Energy Board (December 1998) p. 16.

178 Ibid, p. 27.

179 Ibid, p. 19.

APPENDIX A: INDUSTRY SEGMENT EQUITY THICKNESS HISTORY

The Board's research paper concluded that electric utilities had greater overall risk because the electric utilities were smaller than the gas utilities in Ontario, even though gas utilities had greater business risk than electric utilities.[180]

The Board adopted the proposed risk/equity ratio matrix provided in Figure 40.

Figure 40: Deemed Capital Structure by Risk Class[181]

Risk Category	Rate Base	Common Equity Ratio
Low	≥ $1 billion	35%
Medium/Low	$250 million - $1 billion	40%
Medium/High	$100 million - $250 million	45%
High	≤ $100 million	50%

In 2006, the OEB issued a report on the Cost of Capital which simplified its approach to capital structure for electric utilities by utilizing a common debt-to-equity ratio of 60:40. The Board ultimately determined that size is not the fundamental determinant of risk.[182] The OEB believed that differing capital structures of distributors could serve as barriers to consolidation and noted that small distributors could have greater leverage in their actual capital structures than their deemed equity thicknesses, which would not prevent those small distributors from obtaining financing.

The Board outlined a schedule to transition all of Ontario's electric distribution utilities to the single deemed capital structure of 60 percent debt (56 percent long-term debt and 4 percent short-term debt) and 40 percent equity by the end of 2010. The electric distribution utilities made the transition to the common capital structure during the rate application process.

Electric Transmission

The capital structure for electric transmission companies is determined on a case-by-case basis. The OEB Staff Reports in 2009 and 2016 and its 2023 Cost of Capital Parameter Updates set the deemed

180 Ibid, p. 13.
181 OEB, Electricity Distribution Rate Handbook (March 9, 2000), Table 3-1, p. 3-7.
182 Ontario Energy Board, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors (December 20, 2006) p. 7.

APPENDIX A: INDUSTRY SEGMENT EQUITY THICKNESS HISTORY

capital structure for electric transmission companies at 40% equity, 56% long-term debt, and 4% short-term debt.

In the proceeding in EB-2020-0150 to set electricity transmission rates for UCT, the OEB stated that "[t]he OEB finds it appropriate to set NextBridge's capital structure for rate-making purposes using a 60% debt and 40% common equity structure. This structure is consistent with the OEB's 2009 Report. The 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt."[183]

Ontario Power Generation

OPG submitted its first cost of service application to the OEB in 2007. The OEB's order, issued on November 3, 2008, stated, "the approach to setting capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities."[184] The OEB applied the stand-alone principle in establishing OPG's capital structure, noting that Provincial ownership was not a key factor considered by the Board in establishing capital structure.[185] The OEB determined that OPG possessed greater risk than any other energy utility in Ontario but lower risk than merchant generators, and allowed a 47 percent deemed equity ratio for OPG. The capital structure was applied to OPG's hydroelectric and nuclear businesses, but the Board concluded it would examine separate capital structures for the two business segments during the next proceeding.

In 2009, the OEB concluded that OPG's current capital structure was appropriate, upholding the policy that capital structure should be reviewed only when there is a material change in a utility's financial or business operations.

In its March 11, 2011, decision, the OEB found that "there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate."[186]

---

183 EB-2020-0150, Decision and Order, June 17, 2021, p. 32.
184 EB-2007-0905, Decision with Reasons, November 3, 2008, p. 136.
185 Id., p. 140.
186 EB-2010-0008, Decision with Reasons, March 10, 2011, p. 116.

APPENDIX A: Industry Segment Equity Thickness History

In 2013, the OEB determined that OPG's business risks had changed from the addition of 48 hydroelectric assets and the Niagara Tunnel Project. The OEB found that the addition of hydroelectric assets and the Niagara Tunnel Project "increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now [*i.e.*, as of EB-2013-0321]."[187] The Board lowered OPG's deemed equity ratio from 47 percent to 45 percent.

The Board has maintained the deemed equity ratio for OPG at 45 percent since the 2013 Order. In 2016, the OEB concluded that nuclear generation presents more business risks than hydroelectric generation and that OPG's nuclear rate base would "increase substantially over the five-year term of [of the period over which rates were being set],"[188] but the Board noted that nuclear-generated MWh will not increase relative to hydroelectric MWh.

In EB-2020-0290, OPG requested an equity ratio of no lower than 50%, citing its increased risk profile over the upcoming rate setting period (i.e., 2022-2026) due to the Darlington Refurbishment Program ("DRP") and other nuclear-specific risks, as well as a disparity between OPG's then-authorized equity thickness and the equity ratios for less risky North American utilities. OPG entered into a settlement in that proceeding that left its equity thickness unchanged at 45%.

187 EB-2013-0321, Decision with Reasons, November 20, 2014, p. 113.
188 EB-2016-0152, Decision and Order, December 28, 2017, p. 102.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
Enbridge Gas Inc.	A-/A/n.a.	Enbridge Gas Inc. operates as a rate-regulated natural gas distribution, storage, and transmission utility provider to residential, commercial, and industrial customers in Ontario. The company's distribution system carries natural gas from the point of local supply to customers and consists of main and service pipelines, as well as high-pressure transmission pipelines and five mainline compressor stations. It also provides natural gas storage and transportation services. The company was founded in 1848 and is based in North York, Canada. Enbridge Gas Inc. operates as a subsidiary of Enbridge Inc.	Excellent	Significant	DBRS: • Low-risk regulated operations • Strong franchise area with a very large customer base • Sizable storage assets provide additional rate base and cash flow	DBRS: • Volume risk • Managing operating costs under the price-cap IR plan • Potential regulatory lag • "Uncertainty around upcoming regulatory outcomes related to EGI's gas utility operations and the potential for increased business risk from the energy transition. OEB believes this is underway, creating a risk of stranded assets for EGI, which could impede EGI's long-term capital spending initiatives, indicating higher business risk."[189]	• In EB-2022-0200, the OEB found: "Considering both a decrease in business risk due to amalgamation, and an increase in business risk due to the energy transition, which is partially mitigated by this Decision and Order, the OEB concludes that there is a net increase in business risk that justifies a modest increase in the deemed equity thickness."[190]	
Ontario Power Generation	BBB+/ A(low)/ A3	Ontario Power Generation Inc. engages in the generation and sale of electricity. It also provides ancillary services, such as voltage control and reactive support, black start facilities, and regulation and other services; nuclear waste management services; and	Strong	Significant	S&P: • Lower-risk, rate-regulated utility operations. • Diverse portfolio of power-generating assets. • High likelihood of extraordinary	S&P: • Limited geographic and regulatory diversity. • Refurbishment of legacy nuclear generation plant	OPG's risks related to the Energy Transition are subsumed in many of its company-specific risks that have increased as OPG invests in its facilities and builds new power plants to	• S&P: "Our ratings on OPG incorporate a high likelihood that its provincial owner, the Government of Ontario, will provide extraordinary

[189] S&P Global, "Enbridge Gas Inc. 'A-' Rating Affirmed; Outlook Remains Negative," June 28, 2024, p. 2.
[190] OEB Decision and Order in EB-2022-0200, December 21, 2023, p. 68.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
		heavy water sales and detritiation services, as well as sells medical isotopes. As of December 31, 2023, the company owned and operated two nuclear generating stations, 66 hydroelectric generating stations, two thermal generating stations, one solar facility, and four combined-cycle gas turbine plants in Ontario, Canada. Ontario Power Generation Inc was founded in 1999 and is based in Toronto, Canada.			government support. Moody's: • Primarily regulated generation facilities support stable cash flow generation • Non-regulated generation segment dominated by long term contracts • Expectation of support from the Province of Ontario given its 100% ownership • Diversification benefits by generating station and unit, and fuel source DBRS: • Reasonable regulatory framework that provides stable cash flow • Support of shareholder (the Province) • Limited nuclear waste management liabilities	exposes it to execution risk. • Robust capital spending leads to negative discretionary cash flow, indicating a need for external funding. Moody's • CAD12.8 billion nuclear refurbishment and planned construction of an SMR have significant execution risk • Merchant cash flow entails more risk • Availability risk across the fleet, including low levels of hydrology risk DBRS: • Nuclear generation risks • Political intervention • Exposure to nonregulated operations • Significant capex program • High cost base	meet increasing electricity demand. To that point, OPG's role as a regulated electricity generator puts the company in a unique position to meet growing demand as electrification and clean energy goals advance as part of the Energy Transition, but this will require large upfront investment and carries a wide range of risks associated with construction. Moody's: • "OPG's E-3 score reflects exposure to physical climate risks mostly due to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets also have exposure to waste management and pollution risks. While the company has not had any issues with its nuclear fleet or nuclear	support to the utility during periods of financial distress." (SACP is bb+)[192] • Moody's: "Ontario Power Generation's (OPG) A3 rating reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 positive)."[193] • Moody's: "The company is pursuing a CAD12.8 billion nuclear refurbishment project across 4 units at its Darlington nuclear generation station that carries a high level of execution risk. The company is also moving forward with a small modular reactor (SMR) at

[192] S&P Global, "Ontario Power Generation Inc.," August 8, 2023, p. 8.
[193] Moody's Ratings, "Credit Opinion: Ontario Power Generation Inc.," June 12, 2024, p. 1.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
							waste, it remains an inherent risk for nuclear operators. The company has limited exposure to carbon transition risks owing to its portfolio of primarily nuclear and renewable assets. "[191]	Darlington which carries significant execution risk. OPG expects to complete construction of the SMR in 2028."[194] • Other risk factors: ○ Cyber security (heightened with nuclear) ○ Supply chain (unique assets) ○ Labor (specialized work force) ○ Project execution risk is inherently elevated due to complexity of capital work: ▪ DRP ▪ Pickering refurbishment[195] ▪ Hydroelectric (Saunders, Niagara) ○ Climate change/ extreme weather
Alectra Utilities Corporation	A-/ A/ n.a.	Alectra Utilities Corporation is wholly owned by Alectra Inc. Alectra Inc was formed	Excellent	Significant	S&P: • Majority of cash flows from low-	S&P: • Deferral of COVID-19 costs recovery	• "The electricity distribution infrastructure is	Risks: • Forecasting risk • Technological risk

191 Moody's Ratings, "Credit Opinion: Ontario Power Generation Inc.," June 12, 2024, p. 7.
194 Ibid.
195 There are certain elements of the Pickering Refurbishment Project that will make it more complex and risky than the Darlington Refurbishment Project, including: (1) replacement of the steam generators; (2) Pickering is an older plant, increasing the risk of discovering new issues; and (3) Pickering is installing a deep water intake.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
		on January 31, 2017 as a result of the merger of PowerStream Holdings Inc, Enersource Holdings Inc and Horizon Holdings In. The Credit ratings apply on the holding company level, i.e., Alectra Inc.			risk regulated electricity distribution operations. • Credit-supportive regulatory environment. • Mostly residential customers with minimal concentration risk. DBRS: • Stability from regulated business • Strong franchise area with good growth • Reasonable financial profile	could weaken financial measures modestly. • Limited geographic and regulatory diversity. • Negative discretionary cash flow indicating external funding needs. DBRS: • Operational challenges and performance pressure under IR • Exposure to higher-risk nonregulated business • Limited access to equity capital market	particularly vulnerable to climate change. This is because it has the most linear infrastructure above-ground that is directly exposed to climate hazards. As well, for cost-effectiveness reasons, the distribution system is built to lower engineering thresholds than the core transmission system."[196] • "While the future impacts of climate change on Ontario's distribution system are anticipated to be significant, at present, these potential impacts are not well-understood at a local or regional scale."[197] • "In addition to direct physical risks to their	• Performance expectations (reliability and resilience) • Changing business model (two-way power flows; now mandated to assess non-wires alternatives; expected to look at 3rd party solutions) • Unanticipated capital expenditure risk • S&P: "We believe there is a low likelihood that the utility's municipal owners would provide timely and sufficient extraordinary support in the unlikely event of financial distress."[199] • S&P: "However, beginning in 2024, the OEB allowed the LDCs to implement new preliminary transmission

[196] Ontario Ministry of Energy, Governance, Strategy and Analytics Branch, "Vulnerability Assessment for Ontario's Electricity Distribution Sector: Report on Anticipated Climate Change Impacts and Considerations for Adaptation and Resilience," May 2024, p. 1.
[197] Id., p. 2.
[199] S&P Global, "Alectra Inc.," April 30, 2020, p. 5.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
							systems, evidence suggests that utilities face secondary financial, legal and reputational risks as a result of climate change, particularly if they fail to take action to adapt. Municipalities in Ontario have faced lawsuits for failing to protect residents from increased flooding due to climate change. In California, Pacific Gas and Electric (PG&E) underwent bankruptcy proceedings and was placed on criminal probation after the utility's equipment started several wildfires during extremely dry and windy conditions."[198]	rates at about the same time that the OEB authorizes such rates for the transmission companies, substantially reducing the regulatory lag. Overall, we view the OEB's proactiveness to quickly address this regulatory lag as constructive and consistent with our view of Ontario's regulatory construct as a most credit supportive regulatory jurisdiction."[200]
Elexicon Energy Inc.	n.a./A/n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	*See Alectra discussion*	*See Alectra discussion*

[198] Ontario Ministry of Energy, Governance, Strategy and Analytics Branch, "Vulnerability Assessment for Ontario's Electricity Distribution Sector: Report on Anticipated Climate Change Impacts and Considerations for Adaptation and Resilience," May 2024, p. 10.

[200] S&P Global, "Research Update: Alectra Inc. Outlook Revised To Stable From Negative Due To Expectation Of Reduced Regulatory Lag; Ratings Affirmed," March 20, 2024, p. 2.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
Hydro One Networks Inc.	A/ A(high)/ n.a. (ratings reflect Hydro One Inc., not Hydro One Networks Inc.)	Hydro One Inc., together with its subsidiaries, transmits and distributes electricity to local areas and industrial customers and homes in Ontario. Hydro One Inc. was formerly known as Ontario Hydro Services Company Inc. and changed its name to Hydro One Inc. on May 1, 2000. The company was incorporated in 1998 and is based in Toronto, Canada. Hydro One Inc. operates as a subsidiary of Hydro One Limited.	Excellent	Significant	S&P • A relatively strong regulatory structure that supports stable cash flows. • Low-risk electricity transmission and distribution business. • Only operates in Ontario but has a large footprint across the province. DBRS: • Reasonable regulatory environment ("HOI's deemed capital structure (debt-to-equity of 60%:40%);" "DBRS Morningstar views the utility regulatory framework in Ontario as transparent and supportive for regulated transmission and distribution operators.) • Extensive franchise area • Reasonable financial profile	S&P: • Elevated capital spending to replace aging infrastructure over the next several years could lead to weaker financial measures. • Low likelihood of extraordinary government support. DBRS: • High level of planned capex • High dividend payouts • Earnings sensitive to volume and costs	*See Alectra discussion*	Risks: • Supply constraints • Billing unit differences (no ability in Custom IR to update for new additions) • Large capital deferrals ($5 million in new transmission lines directed by the government and/or IESO); only accruing carrying costs at the cost of debt • Competition (introduced in 2012)

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
Hydro Ottawa Limited	n.a./A(low)/n.a.	Hydro Ottawa Limited is a regulated electricity local distribution company operating in the City of Ottawa and the Village of Casselman. As the third largest municipally-owned electrical utility in Ontario, Hydro Ottawa Limited serves approximately 364,000 residential and commercial customers across 1,116 square kilometres.	n.a.	n.a.	DBRS:[201] • Stability from regulated business: Hydro Ottawa benefits from stable earnings and cash flow generated by its regulated electricity distribution business. Hydro Ottawa operates under a five-year Custom IR allowing it to generate relatively stable earnings and cash flows with reasonable inflation, productivity, and stretch factors. • Strong franchise: Hydro Ottawa is one of the largest municipally owned local distribution companies in Ontario, serving the densely populated areas within the City and the Village of Casselman. The majority of Hydro Ottawa's electricity sales are to residential customers; the federal government; and the	DBRS[166]:: • Large capex program: Hydro Ottawa is in the middle of major capex programs to enhance the reliability of the system and meet growing demographic demands. The OEB-approved Hydro Ottawa's Custom Incentive Rate-setting (IR) application from 2021 to 2025 includes capex spend averaging more than $115 million per year. DBRS Morningstar expects this will result in Hydro Ottawa continuing to generate modest deficits in free cash flow over the medium term. • No access to equity markets: Hydro Ottawa's ownership structure (100% owned by the City) limits its ability to directly access	*See Alectra discussion*	*See Alectra discussion* S&P: "Our view of the relationship between HOHI and the City of Ottawa, its municipal owner, remains the same. We believe there is a low likelihood that Ottawa will provide extraordinary and timely support to HOHI during periods of financial distress."[202]

201 DBRS Morningstar; Rating Report for Hydro Ottawa Holding Inc., October 18, 2023
202 S&P Global, "Hydro Ottawa Holding Inc.," September 25, 2019, p. 8.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
					municipalities, universities, schools, and hospitals (MUSH) sector. DBRS. •	equity markets. As a result, Hydro Ottawa finances any cash flow deficits largely through its revolving credit facilities and debt issuances. •		
Toronto Hydro-Electric System Limited	A/A/n.a.	Toronto Hydro-Electric System Limited owns and operates electricity distribution utilities. The company was founded in 1911 and is based in Toronto, Canada. Toronto Hydro-Electric System Limited operates as a subsidiary of Toronto Hydro Corporation.	Excellent	Significant	S&P: • "Our assessment reflects the company's low-risk, regulated distribution utility operations that provide an essential service to the city of Toronto. THC also serves a diverse customer base of about 793,000 customers with limited concentration risk. Our assessment of the company's business risk profile is also supported by the generally constructive regulatory framework in Ontario."[203]	DBRS: • Balance sheet pressure as a result of high CapEx • Limited access to equity market • Earnings sensitive to volume ("While volume risk has been largely eliminated for residential customers through a fixed charge, distribution rates for commercial and industrial customers (71% of revenue in 2022) continue to be based on fixed and volumetric components."[204])	*See Alectra*	*See Alectra discussion* Note, DBRS considers Toronto Hydro's deemed equity to be "satisfactory" (the third level on a scale from "poor" to excellent") S&P: "The city of Toronto (the City) recently agreed to contribute C$300 million of equity to Toronto Hydro Corp. (THC) over the next 10 years and reduce its dividend targets for the period from 2025-2034. As such, we revised our outlook on THC to positive from stable reflecting the positive outlook on the City and our expectations

[203] S&P Global, "Toronto Hydro Corp. Outlook Revised To Positive On Announced Equity Injections, Ratings Affirmed," July 16, 2024, p. 2.
[204] Morningstar DBRS, "Toronto Hydro Corporation," May 1, 2023, p. 3.

APPENDIX B: ONTARIO UTILITY CREDIT AND RISK FACTORS

Company	Credit Ratings (S&P/ DBRS/ Moody's)	S&P Capital IQ Description	S&P Business Risk	S&P Financial Risk	Credit Positives (per ratings agencies)	Credit Negatives (per ratings agencies)	Energy Transition and Climate Change Risks	Other Notes
					DBRS: • Reasonable regulatory environment • Strong and growing franchise area • Reasonable financial profile			that THC's stand-alone financial measures will modestly improve."[205]
Upper Canada Transmission Inc.	n.a. /A (low)/ n.a.	Upper Canada Transmission, Inc. develops electricity transmission lines. The company was incorporated in 2011 and is based in Canada. Upper Canada Transmission, Inc. operates as a subsidiary of NextEra Energy Canada, LP	n.a.	n.a.	DBRS: • Low business risk and the supportive regulatory environment • "East-West Tie is regulated under a Custom Incentive Rate-setting (IR) regime where it can recover all prudent costs and earn a reasonable return on equity (8.34% for 2022 to 2027)."[206]	DBRS: • Refinancing risk • Limited access to equity markets • Reliance on a single transmission line for its revenues and cash flows	*See Alectra discussion*	Risks: • Single asset lacks diversification • Lack incentives available to U.S. transmission projects (e.g., clarity on abandoned plant; accrue AFUDC at WACC; recovery of development costs)

205 S&P Global, "Toronto Hydro Corp. Outlook Revised To Positive On Announced Equity Injections, Ratings Affirmed," July 16, 2024, p. 1.
206 Morningstar DBRS, "Morningstar DBRS Confirms East-West Tie's Ratings at A (low) with Stable Trends," May 1, 2024, p. 1.

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

JAMES M. COYNE
SENIOR VICE PRESIDENT

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before federal, state and provincial jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University and an M.S. in Resource Economics from the University of New Hampshire.

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

University of New Hampshire
M.S., Resource Economics, *with honors*, 1981

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

- Community Rowing Inc., Board of Directors, 2015 - 2019
- Georgetown University, Alumni Admissions Interviewer, 1988 – current

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

- NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
- American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
- National Petroleum Council, Regulatory and Policy Task Forces, 1992
- President, International Association for Energy Economics, Dallas Chapter, 1995
- Gas Research Institute, Economics Advisory Committee, 1990-1993
- NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

ARTICLES AND PUBLICATIONS

- "Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.
- "Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.
- "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.
- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- "Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPEAKING ENGAGEMENTS

- "The Market Risk Premium: An In-Depth Review", Society of Utility and Regulatory Financial Analysts 53rd Financial Forum, Richmond, VA, April 28,2022
- "Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.
- "Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.
- "Rate of Return: Where the Regulatory Rubber Meets the Road," CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.
- "Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015
- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

APPENDIX C: Author Resumes and Testimony Listings

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
Enmax Power Corporation	2023	Enmax	27084	2024 and Beyond Cost of Capital Parameters
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	G-129-16	Cost of Capital (Gas and Electric Distribution)
FortisBC	2022	FortisBC Utilities	G-217-22	Cost of Capital (Gas and Electric Distribution)
California Public Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Electric & Gas Distribution)
San Diego Gas & Electric Company	2021	San Diego Gas & Electric Company	A-21-08-014	Cost of Capital (Electric & Gas Distribution)
Southern California Gas Company	2022	Southern California Gas Company	A-22-04-011	Cost of Capital (Gas Distribution)
San Diego Gas & Electric Company	2022	San Diego Gas & Electric Company	A-22-04-012	Cost of Capital (Electric & Gas Distribution)
Canada Energy Regulator				
Enbridge Pipelines Inc.	2021	Enbridge Pipelines Inc.	RH-001-2020	Cost of Capital (Oil Pipeline)

APPENDIX C: Author Resumes and Testimony Listings

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startrans IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
South First Energy Operating Companies	2020	South First Energy Operating Companies	ER21-253-000	Cost of Capital (Electric Transmission)
DCR Transmission, L.L.C.	2023	DCR Transmission, L.L.C.	ER23-___-000	Cost of Capital (Electric Transmission)
Florida Public Service Commission				
Florida Power & Light Company	2021	Florida Power & Light Company	Docket No. 20210015-EI	Cost of Capital (Electric)
Georgia Public Service Commission				
Georgia Power Company	2022	Georgia Power Company	44280	Cost of Capital (Electric)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition
Versant Power	2021	Versant Power	MPUC Docket No. 2020-00316	Cost of Capital (Electric)
Versant Power	2022	Versant Power	2022-00255	Cost of Capital (Electric)
Versant Power	2024	Versant Power	2023-00336	Cost of Capital (Electric)
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Energy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Gas)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)
Newfoundland Power	2021	Newfoundland Power	2021 GRA	Cost of Capital (Electric)
Newfoundland Power	2023	Newfoundland Power		Cost of Capital (Electric)

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
North Carolina Utilities Commission				
Duke Energy Carolinas, LLC	2023	Duke Energy Carolinas, LLC	E-7, Sub 1276	Return on Equity (Electric)
Piedmont Natural Gas	2024	Piedmont Natural Gas	G-9, Sub 837	Return on Equity (Gas Distribution)
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Nova Scotia Power Inc.	2022	Nova Scotia Power Inc.	2022 GRA	Return on Equity/Business Risk (Electric)
Eastward Energy Inc.	2023	Eastward Energy Inc.	M10960	Return on Equity/Business Risk (Gas)
Public Utility Commission of Ohio				
Duke Ohio, Inc.	2022	Duke Ohio, Inc.	22-507-GA-AIR	Return on Equity (Gas)
Public Utility Commission of Oregon				
Northwest Natural Gas	2023	Northwest Natural Gas	UG-490	Return on Equity (Gas)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Ontario Power Generation	2020	Ontario Power Generation	EB-2020-0290	Capital Structure (Electric Generation)

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Enbridge Gas Distribution	2022	Enbridge Gas Distribution	EB-2022-0200	Capital Structure and Business Risk
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Maritime Electric Company	2022	Maritime Electric Company	UE20946	Return on Capital (Electric)
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	2022	Duke Energy Ohio, Inc.	2022-00372	Cost of Capital (Gas Distribution)
Duke Energy Ohio, Inc.	2023	Duke Energy Ohio, Inc.	22-507-GA-AIR	Cost of Capital (Gas)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Carolina Public Service Commission				
Piedmont Natural Gas Company	2022	Piedmont Natural Gas Company	2022-89-G	Return on Equity (Gas Distribution)
Duke Energy Progress	2022	Duke Energy Progress	Docket No. 2022-254-E	Return on Equity (Electric)
Duke Energy Carolinas	2024	Duke Energy Carolinas	2023-388-E	Return on Equity (Electric)
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2023	Vermont Gas Systems, Inc.	23-0561	Return on Equity (Gas Distribution) Rebuttal
State Corporation of Virginia				
Dominion Energy Virginia	2021	Virginia Electric and Power Company	PUR-2021-00058	Cost of Capital (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Northern States Power Company	2021	Northern States Power Company	4220-UR-125	Cost of Capital (Electric, Affidavit)

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern States Power Company	2023	Northern States Power Company	4220-UR-126	Cost of Capital (Electric & Gas)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

DANIEL S. DANE, CPA
PRESIDENT

Daniel S. Dane has more than 20 years of experience in the energy, utility, and financial services industries advising electric, gas, and water utilities, power generators, and natural gas pipelines in the areas of regulation and ratemaking, litigation, mergers and acquisitions, valuation, and regulatory accounting matters. Mr. Dane also provides expert testimony on regulated ratemaking matters and merger approval applications for investor- and provincially-owned utilities, including on multi-year rate plans and earnings sharing mechanisms, corporate finance matters such as the cost of capital and capitalization, merger impacts, revenue requirements, lead-lag studies/cash working capital, and regulatory policy. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is also a certified public accountant.

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation Assignments

Expert Testimony

- Submitted expert testimony on behalf of utilities and other stakeholders in state and provincial administrative rate setting and merger approval proceedings regarding multi-year rate plans and earnings sharing mechanisms, corporate finance matters such as the cost of capital and capitalization, merger impacts, revenue requirements, lead-lag studies/cash working capital, and regulatory policy.

Regulatory Advisory

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: performance-based ratemaking; cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; securitization and ratemaking policy.
- Consulting assignments have included utility clients across the U.S. and Canada.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

- Sell-side support for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

- Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation, natural gas pipeline facilities, and water/wastewater utilities.
- Regulatory policy, ring-fencing, and merger impacts advisory services including expert testimony, provided to U.S. and Canadian investor-owned utilities.

Valuation Services

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

Litigation Advisory Assignments

Prepared economic and valuation analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

Management and Operations Consulting Assignments

Performed prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear-generating capacity uprates and new nuclear facilities.

Performed operations and financial performance benchmarking and studies of productivity programs.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
President and Vice Chair

CE Capital Advisors, Inc. (2004 – 2023)
A FINRA-Member broker-dealer subsidiary of Concentric Energy Advisors, Inc.

Ernst & Young (2000 – 2001, 2003 – 2004)
Staff Auditor and Database Management Associate

ZIA Information Analysis Group (1997 – 2000)

EDUCATION

Boston College
M.B.A., 2003

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

Colgate University
B.A., Economics, 1996

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004
Massachusetts Society of Certified Public Accountants, 2004
American Institute of Certified Public Accountants, 2011

PRESENTATIONS

"Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs." Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).
"Financial Management and Capital Markets." University of Idaho Utility Executive Course, 2018.
"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, 2015, 2016 and 2017.
"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Regulatory Commission of Alaska				
Golden Heart Utilities, Inc. and College Utilities Corporation	08/21	Golden Heart Utilities, Inc. and College Utilities Corporation	U-21-070 U-21-071	Lead-lag Study Cash Working Capital
Arkansas Public Service Commission				
Liberty Utilities	02/23	The Empire District Electric Company	Docket 22-085-U	Return on Equity Capital Structure
Connecticut Public Utilities Regulatory Authority				
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Lead-Lag Study/Cash Working Capital
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Lead-Lag Study/Cash Working Capital
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Lead-Lag Study/Cash Working Capital
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts Cost of Debt and Credit Quality
SJW Group and Connecticut Water Service, Inc.	04/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts Cost of Debt and Credit Quality
The United Illuminating Company	09/22	The United Illuminating Company	Docket No. 22-08-08	Multi-Year Rate Plan Revenue Requirements
The Southern Connecticut Gas Company and Connecticut Natural Gas Company	11/23	The Southern Connecticut Gas Company and Connecticut Natural Gas Company	Docket No. 23-11-02	Multi-Year Rate Plan Revenue Requirements
Illinois Commerce Commission				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket Nos. 09-0306 thru 09-0311 (cons.)	Rate Base Adjustments Earnings Attrition

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Maine Public Utilities Commission				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
Massachusetts Department of Public Utilities				
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Multi-year Rate Plan Revenue Requirement Lead-Lag Study/Cash Working Capital
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017 Administrative and General Expense Allocations
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Multi-year Rate Plan Revenue Requirement Lead-Lag Study/Cash Working Capital
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement Step Adjustments
Liberty Utilities (Granite State Electric) Corp.	05/23	Liberty Utilities (Granite State Electric) Corp.	Docket No. DG 23-039	Temporary Rates
Liberty Utilities (Granite State Electric) Corp.	05/23	Liberty Utilities (Granite State Electric) Corp.	Docket No. DG 23-039	Multi-Year Rate Plan Revenue Requirement
New Mexico Public Regulation Commission				
El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT	Lead-lag Study/Cash Working Capital
Oklahoma Corporate Commission				
Liberty Utilities Co.	02/22	Liberty-Empire	Cause No. PUD 202100163	Return on Equity Capital Structure
Liberty Utilities Co.	06/22	Liberty-Empire	Cause No. PUD 202100050	Winter Storm Funding and Cost Recovery

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Rhode Island Division of Public Utilities and Carriers				
PPL Corporation	11/21	PPL Corporation and PPL Rhode Island Holdings, LLC	D-21-09	Merger Impacts
South Dakota Public Utilities Commission				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity Capital Structure
Public Utility Commission of Texas				
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-Lag Study/Cash Working Capital
El Paso Electric Company	06/21	El Paso Electric Company	Docket No. 52195	Lead-Lag Study/Cash Working Capital
Railroad Commission of Texas				
Atmos Pipeline – Texas (APT), a division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas (APT), a division of Atmos Energy Corporation	Case No. 00013758	Lead-Lag Study/Cash Working Capital
Vermont Public Utility Commission				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer Financial Capability and Credit Quality

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Nova Scotia Utility Board				
Nova Scotia Power, Inc.	01/22	Nova Scotia Power, Inc.	M10431	Earnings Sharing Mechanism, Storm Rider, and Demand Side Management Rider
Ontario Energy Board				
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Cost of Capital: Equity Thickness
Ontario Power Generation	12/20	Ontario Power Generation	EB 2020-0290	Cost of Capital: Equity Thickness
Hydro One Networks Inc.	08/21	Hydro One Networks Inc.	EB 2021-0110	Productivity Framework Review
Enbridge Gas Inc. (Operating as Enbridge Gas Distribution Inc.)	10/22	Enbridge Gas Inc. (Operating as Enbridge Gas Distribution Inc.)	EB-2022-0200	Cost of Capital: Equity Thickness

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

JOHN P. TROGONOSKI

ASSISTANT VICE PRESIDENT

Mr. Trogonoski has over 30 years of experience in financial and economic analysis, utility regulation, due diligence, business valuation, property taxation, and program administration. Mr. Trogonoski has assisted clients with a variety of regulatory matters, including providing expert testimony and reports on cost of capital, merger approval, and business and financial risk analysis in both the U.S. and Canada. Prior to joining Concentric, Mr. Trogonoski was a member of the Staff of the Colorado Public Utilities Commission where he supervised the financial analysts in the energy and telecommunications sections and filed expert testimony on matters such as rate of return, cost allocation, rate design, incentive regulation, and public policy. He has an M.S. in Business Administration and a B.S. in Marketing from the University of Colorado at Denver.

REPRESENTATIVE PROJECT EXPERIENCE

Utility Consulting

- Testifying expert on cost of capital matters and the assessment of business and financial risk for regulated electric, gas and water utilities in both Canada and the U.S.
- Prepare expert testimony and exhibits for return on equity analysis for numerous North American gas and electric utility clients. This includes preparing direct testimony, responding to data requests, drafting rebuttal testimony in response to intervening witnesses, assisting with hearing preparation, and drafting post-hearing statements of position.
- Prepare expert testimony and exhibits for multiple clients seeking regulatory approval of mergers and acquisitions. This includes summarizing credit rating agency reactions to the proposed mergers, researching merger approval standards, analyzing the benefits of increased financial scale in the utility industry, and developing financial and ring-fencing commitments in order to mitigate any risk that might result from the merger.
- Performed regulatory due diligence for clients considering the potential acquisition of a natural gas distribution company and an electric transmission company. Due diligence included a review of the regulatory framework in the jurisdiction of the target company, potential cost disallowances, an assessment of the projected ROE and capital structure, an evaluation of the reasonableness of projected capital spending based on forecasted economic growth in the service territory, and the implications of these factors on the value of the target company.
- Assisted in the development of a conservation program for New Jersey American Water, which was filed with the Board of Public Utilities in conjunction with the company's rate case. The program included rebates for various indoor and outdoor plumbing fixtures, as well as estimated penetration of the proposed rebate programs, and a cost/benefit analysis in support of the various rebates.
- Analyzed the internal policies and tariff of New Mexico Gas in response to service outages and determined if the time to restore service to customers was consistent with other major gas

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

distribution outages that have occurred across the United States. Offered recommendations to improve the Company's communication with regulators and customers.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2008 – Present)
Assistant Vice President (2020)
Senior Project Manager (2013)
Project Manager (2010)
Senior Consultant

Colorado Public Utilities Commission (1999 – 2008)
Supervisory Financial Analyst, Telecommunications and Energy (2004)
Financial Analyst, Telecommunications, Energy and Water

State of Colorado, Division of Property Taxation (1994 – 1999)
Property Tax Specialist

Nobel Sysco, Inc. (1992 – 1994)
Marketing Associate

State of Colorado, Division of Property Taxation (1989 – 1991)
Tax Appraiser Consultant

EDUCATION

University of Colorado at Denver
M.S. in Business Administration, 1987
B.S. in Marketing (cum laude), 1986

EXPERT REPORTS

- Drafted a report for the Ontario Energy Board that reviewed low-income energy assistance programs that have been implemented in other jurisdictions, including Canada, the United States, the United Kingdom, the European Union countries, Australia, and New Zealand. Attended hearing and responded to questions related to research report on behalf of OEB staff.
- Drafted a report for the Ontario Energy Board that proposed revisions to the Board's existing rules for Demand Side Management for gas distribution companies in Ontario. Participated in workshop and responded to questions from stakeholders regarding the proposed changes to the Board's rules.

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

REGULATORY COMMISSION EXPERIENCE

- Supervised financial analysts and accountants in the energy and telecommunications units of the Colorado Public Utilities Commission from 2004 to 2008. In this capacity, he was responsible for the financial analysis, accounting, and auditing work of between five and nine financial analysts. This included preparation of expert testimony and recommendations concerning rate cases, applications for alternative forms of regulatory treatment, performance of managerial and financial audits, compliance with relevant statutes and Commission rules, and review of applications for certificates of public convenience and necessity, transfers of authority, franchise agreements, and discontinuance of service.
- Provided expert testimony on rate of return issues, capital structure, cost of debt, financial integrity, and credit quality in numerous rate case proceedings involving energy, telecommunications and water companies.
- Performed managerial and financial audits of regulated energy and telecommunications companies using the regulatory and accounting guidelines in the Uniform System of Accounts relied upon by the Federal Energy Regulatory Commission, the Federal Communications Commission, the Financial Accounting Standards Board, and the Commission's rules and regulations.
- Led Staff's review of an application for relaxed regulatory treatment by Qwest Corporation. Provided expert testimony regarding Qwest's market share in Colorado relative to cable providers, wireless providers, and Competitive Local Exchange Carriers. Assisted professional market research firm in designing questionnaire to examine customer preferences for purchasing telecommunications services, expectations concerning price and quality of those services, and desire for regulation over those services.
- Led Staff's investigation into a Competitive Local Exchange Carrier that was providing regulated telephone service to over 14,000 customers without the requisite Commission authority and without an effective tariff. This investigation resulted in a Commission order to cease and desist provision of regulated services, an order to transfer customers to an alternative provider, and sanctions against the principals.
- Administered the Colorado High Cost Support Mechanism, which provided universal telecommunications service to customers in rural, high costs areas through an assessment on all Colorado customers. Also, later supervised the position that administered this program.

PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with James Coyne), Public Utilities Fortnightly, May 2010

OTHER ACTIVITIES

- Member of 401(k) investment committee at Concentric Energy Advisors, Inc. since 2011.

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Utilities Commission				
ENMAX Power Corp.	2022	ENMAX Power Corp.	Application No. 27084	Cost of Capital
Beverage Container Management Board (Alberta)				
Beverage Container Management Board	2019	Beverage Container Management Board	N/A	Return margin for Alberta bottle depots
Colorado Public Utilities Commission				
Colorado PUC Staff	2000	Qwest Corporation	99A-577T	Cost of Capital Composite Income Tax Rate Ad Valorem Tax factor
Colorado PUC Staff	2001	Peetz Cooperative Telephone	01S-321T	Cost of Capital Revenue Requirement Adjustments to Rate Base Adjustment to Operating Expenses Capital Credit Rotation
Colorado PUC Staff	2002	Mile High Telecom	02C-082T	Order to show cause Operating without CPCN or tariff Violation of stipulation – alleged fraud
Colorado PUC Staff	2002	Public Service Company of Colorado – Electric/Gas	02S-315EG	Cost of Capital Dissolution of PS Credit Corporation Financial Integrity and credit ratings Impact of NRG on regulated entity Dividend payments and capital spending
Colorado PUC Staff	2003	Aquila Networks, Inc.	02S-594E	Cost of Capital
Colorado PUC Staff	2003	Lake Durango Water Company	03S-052W	Allowable expenses – depreciation and taxes Value of purchased water Operating Ratio method Rate design for retail/bulk customers Customer impact of proposed rates Enhancement of accounting & financial reporting
Colorado PUC Staff	2003	Roggen Telephone	03S-246T	Cost of Capital
Colorado PUC Staff	2003	South Park Telephone	03A-277T	Request for HCSM support Adjustments to Rate Base Disallowance of Expenses Depreciation rates and USF impact Cost of Capital

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Colorado PUC Staff	2003	Pine Drive Telephone	03S-314T	Cost of Capital
Colorado PUC Staff	2003	Phillips County Telephone	03S-315T	Cost of Capital
Colorado PUC Staff	2004	Aquila Networks, Inc.	04S-035E	Cost of Capital
Colorado PUC Staff	2004	SC TxLink, LLC	04A-508	CPCN for CLEC authority Financial Assurance - bonding
Colorado PUC Staff	2005	Qwest Corporation	04A-411T	History of CLEC competition Wireless competition in Colorado Is Wireless substitute for wireline? Financial barriers to entry Introduce customer survey Analyze and interpret survey results Regulation of retail service in 14 states
Colorado PUC Staff	2005	Public Service Company of Colorado – Gas	05S-264G	Cost of Capital – investor owned Rate design issues in Phase 2 – S&F Charge Impact on rate of return – minimum system
Colorado PUC Staff	2005	Public Service Company of Colorado - Steam	05S-369ST	Cost of Capital
Colorado PUC Staff	2006	Public Service Company of Colorado - Electric	06S-234EG	Cost of Capital Credit quality and cash flow Financial integrity and credit ratings Purchased power and imputed debt Performance based regulatory plan
Colorado PUC Staff	2007	Public Service Company of Colorado - Gas	06S-656G	Cost of Capital Financial integrity and credit ratings
Colorado PUC Staff	2007	Nunn Telephone	07A-124T	Overview of HCSM statutes and rules Use of separation program – revenue requirement Challenges faced with new petition process
Island Regulatory and Appeals Commission (Prince Edward Island)				
Maritime Electric Company	2018	Maritime Electric Company, Ltd.	UE20944	Cost of Capital
Maritime Electric Company	2022	Maritime Electric Company, Ltd.	UE20946	Cost of Capital
Maine Public Utilities Commission				

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Versant Power	2024	Versant Power	2023-00336	Cost of Capital
Montana Public Service Commission				
ABACO Energy Services, LLC	2020	ABACO Energy Services, LLC	D2020.07.08 2	Revenue Requirement, Rate Design, and Cost of Capital.
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	Matter No. 491	Cost of Capital (Rebuttal)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2023	Newfoundland Power	Pending	Cost of Capital
New York Public Service Commission				
New York State Gas and Electric Company and Rochester Gas and Electric	2015	New York State Gas and Electric Company and Rochester Gas and Electric	15G-0284	Cost of Capital (Rebuttal)
Niagara Mohawk Power Corporation d/b/a National Grid	2017	Niagara Mohawk Power Corporation d/b/a National Grid	17-E-0238 17-G-0239	Cost of Capital (Rebuttal)
Pennsylvania Public Utility Commission				
Utilities, Inc.	2019	Community Utilities of Pennsylvania, Inc.	R-2019-3008947	Cost of Capital
Régie de l'Energie du Quebec				
Hydro Quebec Distribution and Hydro Quebec TransÉnergie	2013	Hydro Quebec Distribution and Hydro Quebec TransÉnergie	R-3842-2013	Risk analysis in support of ROE testimony
Vermont Public Utility Commission				
Vermont Gas Systems, Inc.	2019	Vermont Gas Systems	19-0513-TF	Cost of Equity
Yukon Utilities Board				
ATCO Electric Yukon	2023	ATCO Electric Yukon	Pending	Risk Premium above benchmark return on equity

APPENDIX C: AUTHOR RESUMES AND TESTIMONY LISTINGS

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Subpoenas to Provide Expert Testimony				
U.S. Bankruptcy Court – Denver, CO	2005	ON Systems, Inc.	N/A	Testify in U.S. bankruptcy court - value of CPCN for local exchange telecom service
U.S. District Court, Southern District of Florida	2008	USA vs. Wetherald, et al	06-80199-CR-MARRA	Testify on behalf of U.S. government Wire fraud, mail fraud, money laundering