ONTARIO ENERGY BOARD

COST OF CAPITAL GENERIC PROCEEDING

EB-2024-0063

OEB STAFF COMPENDIUM

PANEL 2 - M2 Concentric

September 30, 2024

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

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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)).

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.

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

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

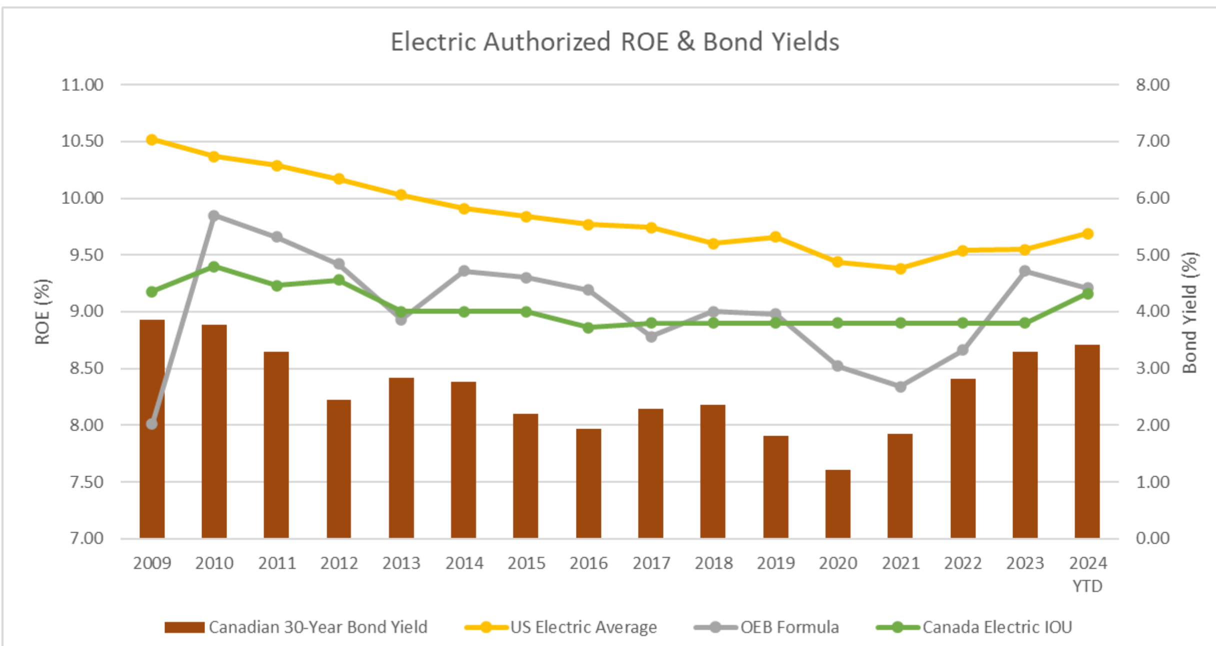
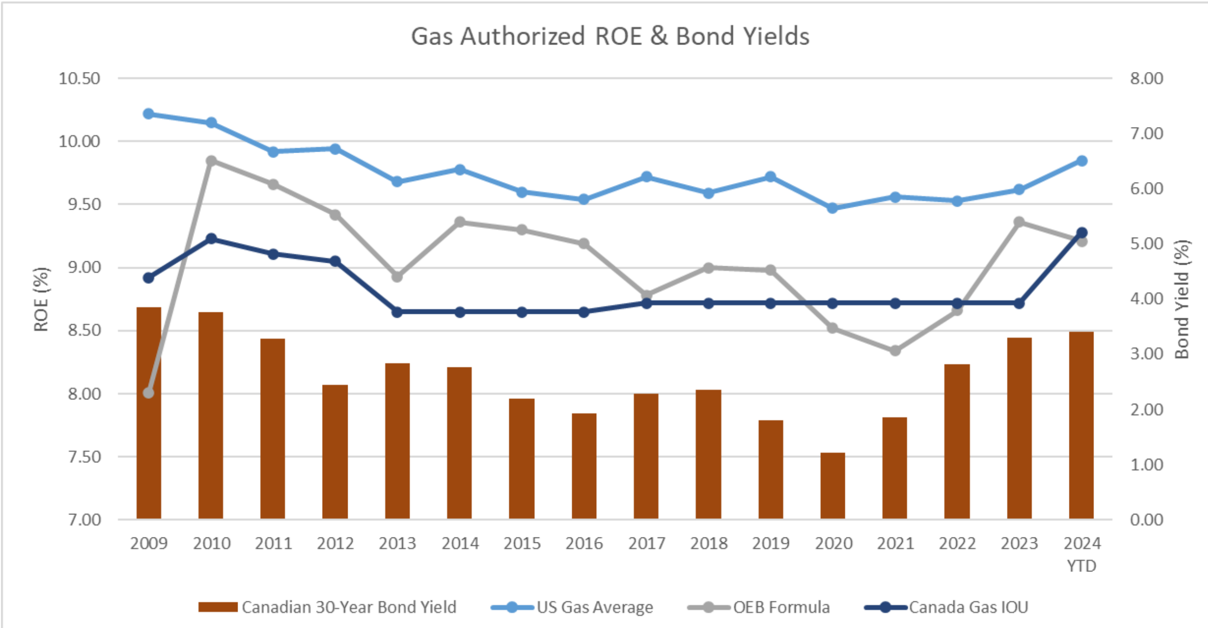


Figure 29: Ontario Formula vs Canadian and U.S. Gas Authorized ROEs



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

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.

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.

London Economics International LLC

Support in the generic proceeding on cost of capital and other matters
(EB-2024-0063)

Presentation Day

AJ Goulding
Amit Pinjani
Shashwat Nayak
September 5, 2024

LE LONDON ECONOMICS

Blume Adjustment arbitrarily inflates the beta

Blume Adjustment is not required, particularly for the regulated utility sector

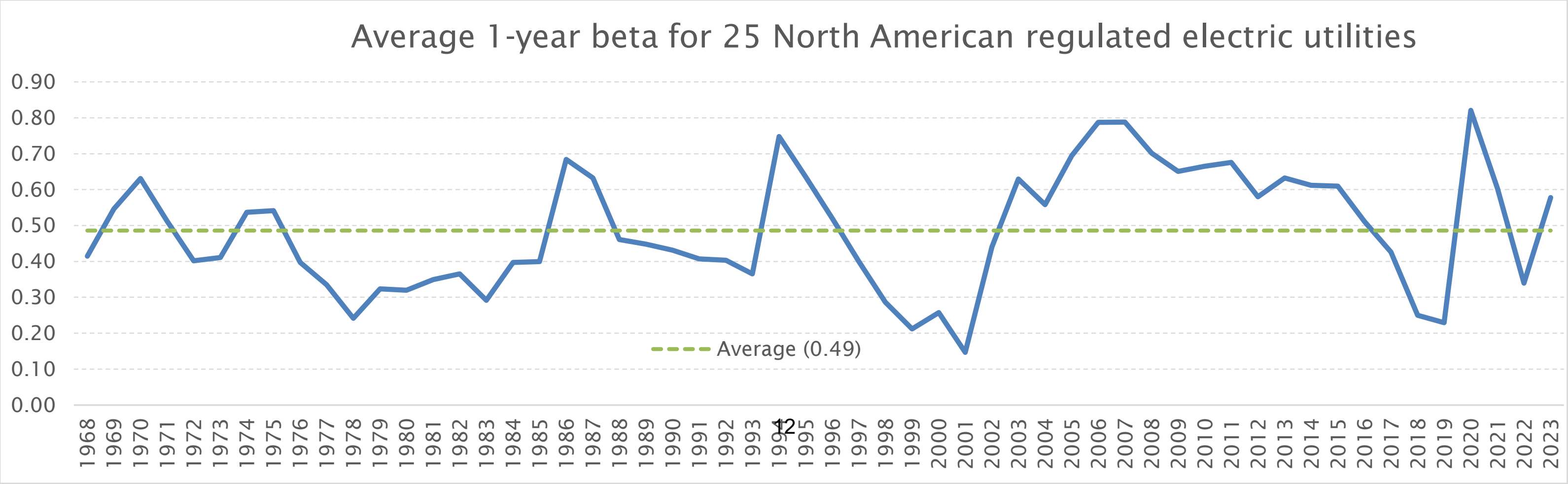
- **No empirical evidence is presented by any party to justify the argument that the beta for regulated utilities moves towards one over the long term**
- **Weights applied for Blume Adjustment (2/3rd towards the raw beta and 1/3rd towards 1) are typically justified by citing a study from June 1975**
- **One of the reasons provided as justification for the Blume Adjustment in the original 1975 citation is that "*companies of extreme risk-either high or low-tend to have less extreme risk characteristics over time*"**
  - In LEI's view, **regulated utility sector cannot be classified as "extreme risk" (low or high)**

LEI utilized a three-step process to estimate the beta

First: LEI populated the raw beta for peer companies

Second: The raw betas were unlevered using the operating leverage of each of the peer companies

Third: The average unlevered beta of the peer group was re-levered using the OEB-allowed deemed capital structure



2024 REVIEW OF COST OF CAPITAL PARAMETERS AND DEEMED CAPITAL STRUCTURE

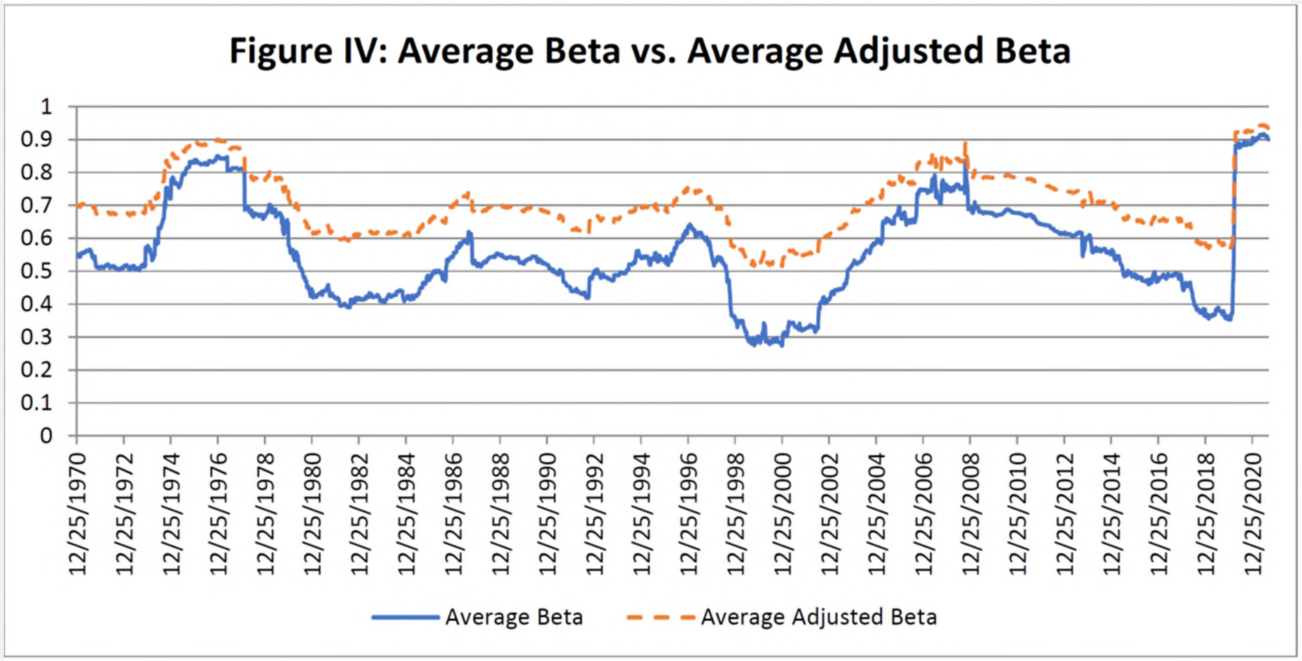
EB-2024-0063

September 5, 2024

Dr. Sean Cleary, CFA
Professor of Finance

Smith School of Business
Queen's University

Beta Estimates



Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

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

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

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

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

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

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

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

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

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

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

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

The Role of the Comparable Investment Standard

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

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

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

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

Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of

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British Columbia Utilities Commission

Generic Cost of Capital Proceeding

(Stage 1)

Decision
and Order G-236-23

September 5, 2023

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

Size of an ROE adder for Flotation Cost

Regarding the appropriate size of flotation costs, Mr. Coyne makes adjustments to the DCF and CAPM results by 50 bps for flotation costs and financing flexibility.[648] However, while Mr. Coyne does not provide a breakdown of the 50-bps adjustment separating flotation costs from financing flexibility, Mr. Coyne notes that for an electric proxy group in the US, flotation costs are typically in the range of 10 to 15 bps and the remainder would be for financing flexibility (i.e. 35 to 40 bps).[649]

Dr. Lesser provides his view on issuance costs as a percentage of equity issued and notes that flotation costs typically have ranged between two percent and five percent of issuance costs[650] to which Mr. Coyne assesses, "doesn't sound unreasonable."[651] Using an assumed flotation cost equal to five percent of total issuance cost and Dr. Lesser's methodology to calculate flotation cost, Mr. Coyne converts Dr. Lesser's data into basis points of ROE, indicating that issuance costs of that magnitude represent approximately 21 to 25 bps of ROE for the gas proxy groups and 19 to 25 bps for the electric proxy groups.[652] Mr. Coyne notes that his estimate of 10 to 15 bps and Dr. Lesser's estimates of 25 bps are "within the range of what we would expect to see for issuance costs."[653]

Table 34: Flotation Cost Adder: Dr. Lesser's Methodology

Flotation Cost Adder: Dr. Lesser's Methodology (basis points)

Proxy Group	FEI	FBC
Canadian Regulated	25	25
US Gas	21	
North American Gas	24	
US Electric		19
North American Electric		20

6.2.2 Financial Flexibility

Financial flexibility refers to a margin, or cushion, for unanticipated capital market conditions,[654] or also as spare borrowing capacity[655] and ability to continue to raise equity in challenging capital market conditions.[656]
Dr. Lesser and Mr. Coyne disagree on inclusion of costs for financial flexibility to compensate for raising capital. Also, if financial flexibility is accounted for, there are varying opinions as to whether the financial flexibility adder should form part of the allowed ROE or deemed equity component of the capital structure.

Dr. Lesser

648 Exhibit B1-8-1, Appendix C, p. 72.

649 Exhibit B1-9, BCUC IR 43.2; 50-bps adjustment less flotation costs range of 10-15 bps equals to 35–40 bps for financial flexibility costs as the residual.

650 Exhibit A2-3, p. 82.

651 Transcript Volume 4, p. 624, ll. 5-17 and p. 625, ll. 6-23.

652 Exhibit B1-25, BCUC IR1 6.1.

653 Transcript Volume 3, p. 354.

654 Exhibit A2-20, BCUC IR 6.6; 2013 Decision, p. 79.

655 Exhibit A2-20, BCUC IR 6.6.

656 Exhibit B1-8-1, Appendix C, p. 69.

The Panel accepts Dr. Lesser's statement that financial flexibility appears to be defined as having spare borrowing capacity and additional cash-on-hand, and thus, appears to be more related to the optimal capital structure and less one of the allowed ROE.[690]

However, Dr. Lesser concludes from this position that flexibility is best incorporated into the capital structure the BCUC sets for FEI and FBC by adjusting each utility's deemed equity ratios. He therefore does not consider an adder for financial flexibility to be just and reasonable.

Mr. Coyne does not appear to disagree. He submits that "if a Canadian regulator was looking to establish financial parity with US peers, then establishing comparable equity ratios (in the 50 percent to 52 percent range) and comparable allowed ROEs (9.5 percent to -10.0 percent range) would accomplish that objective[691] – and in doing so, would obviate the need for a 'financial flexibility' adder to the ROE, as the Canadian utility would now have financial comparability to its U.S. peers which do not have an equivalent adder".
Having found Dr. Lesser's approach to dealing with financial flexibility to be reasonable, the Panel will consider the issue of financial flexibility when it determines the approved capital structure for the two FortisBC public utilities.

Flotation Costs

The Panel accepts that any reasonable and prudently incurred flotation costs incurred by a public utility are recoverable from ratepayers, over and above the approved costs of capital. However, there is no evidence before the Panel that FEI or FBC incurs any flotation costs and therefore there are no costs to recover. Instead, FEI and FBC argue that because their parent incurs flotation costs on their behalf, FEI and FBC should be entitled to a Flotation Cost "adder".

The Panel disagrees. Generally speaking, costs incurred by an unregulated parent are not recoverable from a regulated subsidiary, unless those costs are directly allocated and billed to the subsidiary for services legitimately performed by the parent. This can include approved allocations of costs forecast or incurred by the parent on behalf of its regulated subsidiaries. However, there is no direct link evident to the Panel between the proposed flotation cost adder and actual costs incurred or expected to be incurred by the parent. For example, the adder will be the same if there is an annual equity injection by the parent or if such equity injection only occurs every five years or never occurs.

The Panel finds that the proposed flotation cost adder is too vague to be a just and reasonable expense recoverable from ratepayers. It is a very rough estimate of the actual flotation costs of shares issued by the parent when it issues its own shares to obtain the funds used to purchase the shares of its subsidiaries. Therefore, we reject the proposal to use the flotation cost adder.

FEI and FBC can request recovery of actual costs incurred by the parent by providing applicable invoices or other supporting documentation from the parent when FEI and FBC issue additional equity. That supporting documentation should provide enough detail to enable the BCUC to review it to determine that is a just and

[690] Exhibit A2-20, BCUC IR 6.6.
[691] Exhibit B1-51, BCUC IR 1.1.

reasonable expenditure. Those expenditures, if and as incurred, can be recovered from the ratepayers of FEI, or FBC as the case may be, following review and approval as part of each utility's Revenue Requirement process in the normal course.

6.3 Overall Capital Structure and ROE

Since experts, and the interveners' respective submissions on capital structure, financial model ROE results, adders and other adjustments, have already been reviewed in previous sections, this section will narrowly focus on jointly presenting the interveners' recommended capital structure and overall ROE figures, inclusive of all adders for flotation costs, financial flexibility and other considerations.

FortisBC submits that the BCUC should approve, in accordance with the Fair Return Standard, FEI's proposed common equity ratio of 45 percent with an ROE of 10.1 percent, and FBC's proposed common equity ratio of 40 percent with an ROE of 10.0 percent.[692] These figures are based on the US proxy groups and December 2021 data and consist of a simple average of Mr. Coyne's CAPM and Multi-Stage DCF model results. They are also inclusive of a 50-bps adder for flotation costs and financial flexibility.[693]

Mr. Coyne's recommended increase of FEI's equity ratio from 38.5 percent to 45.0 percent is due primarily to higher business risks as compared to 2016, which include accounting for "elevated Energy Transition risk in BC".[694] Further, Mr. Coyne submits that his recommended 45.0 percent equity ratio for FEI is the "approximate midpoint between average deemed equity ratio for Canadian investor-owned gas distribution companies and the authorized equity ratio for U.S. gas distribution companies since January 2020."[695]

Mr. Coyne explains that capital structure and the cost of common equity are closely linked in determining the fair return for regulated utilities. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate for the additional financial risks in the form of financial leverage to which their shareholders are exposed. Accordingly, regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met.[696]

In its 2013 Decision, the BCUC stated:

> The Commission Panel confirms that the approval of rates to meet the FRS [Fair Return Standard] is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility.[697]

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692 FortisBC Final Argument, p. 3.
693 Exhibit B1-8-1, Figure 1 and Footnote 1, p. 4, Figure 2 and Footnote 2, p. 5.
694 Exhibit B1-20, BCUC IR 76.1.1.1.
695 Ibid., BCUC IR 71.8.
696 Exhibit B1-8-1, Appendix C, p. 147.
697 2013 Decision, p. 12.

and FBC by 47 bps to 9.90 percent.[721] And adding a size premium for FBC, which Mr. Coyne calculates at 105 bps based on Duff & Phelps data, would further increase the CAPM ROE for FBC.[722]

Overall Panel Determination on Capital Structure and ROE

<u>Deemed Equity Component</u>

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

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

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

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

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

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

[721] 9.43% + 0.47% = 9.90%.

[722] FortisBC Reply Argument, p. 51.

increase in FEI's equity component is warranted to compensate for the increased risks faced by FEI's shareholder and investors.

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

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

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

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

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

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

[723] FortisBC Reply Argument, p. 43.

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

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

Notwithstanding these findings, the Panel now needs to consider financial leverage and financial flexibility for FBC to determine whether any upward adjustment to its 40.0 percent equity thickness is warranted. FortisBC and Mr. Coyne are not recommending any capital structure changes for FBC and have not explicitly recommended a size premium in the CAPM analysis for FBC.

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

Return on Equity

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

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

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

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	Pankaj Sardana	**Commissioner**

idea that I talked about earlier, that the TSX has more concentration in particular industry structures. So, if you were to extract from the US the industry composition that would be consistent with the TSX, I suspect you would find not necessarily something that's equal, but you might find lower overall results.

And some of this is skewed by the boom/bust of the resource sector, for example, or, you know, the fact that Canada tends to have a small set of technology champions that do very well for a while, then they fade out or they move to the US. So I think that the industry composition does play a large role in the difference between the outcomes.

MS. ANDERSON: Okay, thank you. And, by the way, just for the reference for the transcript, that was Figure 41. We didn't get it called up, but I will move on.

So my last question is, and I don't know whether it's one for Staff or for you, but your evidence does talk about a formula and that the data would be updated and many times you're referring to September 30th data. Is it part of the engagement for you to update your calculations based on that September 30th or whatever data -- and I will probably ask the same for the other experts -- whatever data was being proposed?

Is that something that's do -- I have no idea how much effort is involved in that.

And, Mr. Richler, I don't know if that's for you. Can it be done without an arduous amount of work?

MR. RICHLER: Well, I think that that last question about what it would take and how arduous it would be, I think LEI should answer that.

MR. GOULDING: I think -- so, first of all, our goal is to be helpful, so -- and I think it's not that arduous to update for a particular date, you know, as -- I think the one problem is the "as of" date does not mean that the data is available September 30th.

MS. ANDERSON: Oh, of course, yes.

MR. GOULDING: But -- and I think I will stop there. We will work to be useful to our client and leave commercial considerations to another conversation.

MS. ANDERSON: Okay. I think for probably each of the evidence, to the extent that the experts have proposed certain data be used in that calculation, I think it would typically be helpful for us to see what it is now. I think, for many cases, that it was like May data that was used, so that might be interesting to see. So we can hold that off to the other parties when they are up, but -- if it's doable as an undertaking, I think that would be helpful, and, if you want to come back to us, that's --

MR. RICHLER: Well, look, we also are trying to be helpful, so, if this is something that the commissioners would like to see, yes, we will ask LEI to do the work. So we will give that undertaking and note it as J2.2.

UNDERTAKING J2.2: TO PROVIDED AN UPDATED ROE ANALYSIS USING MORE CURRENT DATA.

MS. ANDERSON: I am just checking with my fellow Panel members, that they think it's helpful. Yes, thank you. Those are my questions.

MR. JANIGAN: Thank you, Commissioner Anderson. I have two areas of questions. The first one deals with the fact that we are now reviewing a decision that took place in 2009, coming out of the recovery from the crash of 2008, and we set the parameters for the methodology that would be used to provide the cost of capital for utilities up until the time of this review.

I was wondering what changes in the market, the capital markets, have occurred since 2009 and how are those changes reflected in your analysis of where we should go from the 2009 capital decision?

MR. GOULDING: That's an interesting question, and I think I would want to distinguish between the methodology, right, which I think, you know, still captures -- there's nothing esoteric or that was specific to financial conditions in 2009 that is embedded in the formula or the approach. So, you know, from that perspective, I think the concern in 2009 was: Look, we are trying to set up a formulaic approach; we want to make sure that we are updating this on a predictable, regular basis, using various adjustment factors.

And that approach is similar today and I think appropriately so, and so, you know, all of the models that are being discussed by all of the experts are the same models that are discussed, debated, in other jurisdictions. And the concept of a generic cost of capital is less used providing investors comparable risk-adjusted returns."

Do you see that?

MR. COYNE: I do.

MR. RUBENSTEIN: I just want to go back to the question. Are you aware of any real world examples of Ontario utilities being unable to compete for investment capital on comparable basis with its North American peers?

MR. COYNE: I would say that every Ontario utility is not competing at, by and large, on a comparable basis with its North American peers.

MR. RUBENSTEIN: Are you aware of any Canadian utility that is unable to raise equity or debt on reasonable terms?

MR. COYNE: No, I am not and that's not the -- if you look at the, if you look at how we finish the answer to the statement, our view isn't that Ontario's utilities cannot raise the capital that they need. The competitiveness of their ability to continue to raise that capital and the ability to satisfy the fair return standard is the crux of the matter. And the crux of the matter is today's allowed equity ratios do not satisfy the fair return standard, and today's equity ratios do not allow Ontario's utilities to compete against their North American peers on a comparable basis. Now, does that mean they will go out tomorrow and not be able to raise debt capital? Probably not. But does that mean that as they go to capital markets to raise the debt and equity that they need versus and an Exelon, or a Duke, or the other companies we described, if they look at the strength of those balance sheets and the credit metrics that they provide and the strength of Ontario's utilities on a risk-adjusted basis, I think they are going to say I prefer the company with the stronger balance sheet, that's just basic finance.

MR. RUBENSTEIN: But that hasn't happened yet?

MR. COYNE: I am not aware that it's prevented Ontario's utilities from raising the capital that they need, but recall it's a three-prong stool, the fair return standard. And you're referring to one prong of that fair return standard by suggesting that if they can raise the capital they need that that may be sufficient, or at least I am hearing that in your question. But that's not sufficient to satisfying the fair return standard. It also needs to be comparable, and 40 is not comparable to 52.

MR. RUBENSTEIN: They are different, I think I do accept that, I was just asking a question --

MR. COYNE: I am just answering it.

MR. RUBENSTEIN: -- about your experience. Can I ask you to go to page 4 of the compendium, this is an attachment to SEC 54. Can we go to page 5. And am I correct that you have done work, cost of capital work, in Alberta; correct?

MR. COYNE: Yes.

MR. RUBENSTEIN: So, you're familiar with the Alberta landscape?

MR. COYNE: Very much.

MR. RUBENSTEIN: And as I am looking at this table

Ontario

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	Pankaj Sardana	**Commissioner**

or not you issued it at its book value or face value or not.

It's also associated with the fees that you have mentioned, bankers fees, legal fees, everything from printing and book running and even insurance fees and consultants that get hired by both the lender -- by the lender and the bank that is associated with the offering. All those fees go into the cost of obtaining that equity. Those are the costs that were designed to recover through a flotation cost adjustment.

And, as we discuss in our testimony, the Figure 20 on page 73 in our report shows the long-standing practice in Canada to reflect those costs in this 50-basis-point adjustment that goes back in time as long as we have been practicing in Canada. And I think the 50-basis-point precedent goes back at least as far as 2006 in British Columbia. And, over time, Canadian regulators have adopted it as an estimate of not just flotation costs but also the financial flexibility adjustment.

MR. RUBENSTEIN: So, just to be clear, and BC you just mentioned, BC has gone back -- they just got rid of it; fair?

MR. COYNE: No, they didn't get rid of it. They have now, according -- in the most recent BC decision, they have decided to reflect flotation cost and flexibility in the equity ratio for FEI and FPC.

MR. RUBENSTEIN: Can I ask you to flip to page 314 of the compendium. Just to help you understand what this is, I was only scheduled for 30 minutes, and I marked down that I started at about 10:40, so I think I only have about six minutes left on the clock.

MR. JANIGAN: Okay. We are not quite running a stopwatch here, but we will take your word for it, and I will allow you to finish.

MR. POLLOCK: Thank you very much, sir.

MR. TROGONOSKI: Okay. I found the data request. It is CCC-4, Attachment 2. We provide there the spreadsheet that I am referring to, that supports the narrative that's on page 126 of our report.

MR. POLLOCK: Thank you very much, Mr. Trogonoski. Maybe I might switch gears just for a moment. So if I could bring us to page 9 of the report, which is PDF page 15. So, if we scroll to the bottom -- so, as I understand it, we have the bottom paragraph here that says:

> "Based on the results", which you have listed above, "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."

Do you see that?

MR. COYNE: Yes.

MR. POLLOCK: Now, when I read this, the use of the word "diverged" made me understand that your position -- and you can correct me if I am wrong -- is that, at some point since its inception in 2009, the formula produced returns on an absolute basis that did meet the fair return standard but has since changed such that it no longer does; is that an accurate understanding of your position?

MR. COYNE: No, that's not our statement because to do so would have required us looking at the cost of equity for every year since 2009 for Ontario's utilities, which we haven't done. So the assumption -- the use of "divergence" means, as we sit here today, we do not see alignment between the fair return and what the formula is producing.

So we have not examined each year of -- as I understand your question, have we determined when they diverged, and we have not, only that we are diverged as we sit here today.

MR. POLLOCK: And I think you talked with Mr. Rubenstein yesterday about, I think, trying to disaggregate your position with respect to the other two components or legs of the fair return standard. And, as I understood your answer, it is not your position that there have been any instances where is Ontario utilities have either failed to attract capital on reasonable terms or have had their financial integrity threatened; is that fair?

MR. COYNE: That's correct.

MR. POLLOCK: And I want to just ask you, since I only have a couple minutes left, is this state of affairs -- and I will give you the premises of the question. The state of affairs that I am referring to is, number one, that

MR. MONDROW: And does that mean that under CAPM, the CAPM methodology, your proposed ROE would be higher, just under that, the results of that methodology?

MR. TROGONOSKI: No, it doesn't. They are separate methodologies.

MR. MONDROW: You were talking about the equity risk premium methodology, not the CAPM methodology?

MR. TROGONOSKI: Correct.

MR. MONDROW: Got you. You are not changing your proposal for ROE based on that answer to Ms. Stothart's question, I assume?

MR. TROGONOSKI: As I recall her questioning, she began by asking about the CAPM model and the effect there, of re-levering. And we answered that question in the affirmative. And then she went on to the equity risk premium model, and we had the same answer to that question.

MR. MONDROW: You are not changing your ROE recommendation based on that exchange, "you" being Concentric?

MR. TROGONOSKI: We are not. We are just pointing out the fact that if the Board were to maintain the equity ratios where they are now in Ontario, then our 10 percent ROE would need to be adjusted upward for that higher financial risk.

MR. MONDROW: Right. And under the current equity ratio, your ROE recommendation would actually be, if I recall correctly, 11.1-something; isn't that right? Something like that?

be fair, and this has actually been shown in the compendium that we just saw from Mr. Mondrow, is later on in that same decision based on --

MR. COYNE: Could we just turn to that page in Mr. Mondrow's compendium?

MR. GARNER: Certainly, unfortunately Mr. Mondrow's compendium doesn't have the part I just quoted, but at page 32 of his compendium it does have the second part which I think is what you were referring to in your answer. And if that can be brought up but while it's being brought up it's pretty simple, it says:

> "In light of our decision to consider financial leverage, financial flexibility in the capital structure we find a modest adjustment in the equity thickness of 1 percent for FBC is warranted to conform with the fair return standard, therefore the panel deems that the deemed equity component for FBS is 41.0."

Now, why I bring that up is not just to be clear, but there is a distinction being made here; right? There is a distinction being made between the idea of flotation costs and flexibility, financial flexibility, and financial leverage; right? And so, I wanted to be clear about that. Now, in your evidence, do you -- remind me, do you draw a basis point difference between those two things in the sense of how you adjust that? And something tells me it's like 25 basis points for flotation, 25-basis points for flexibility; is that correct?

MR. COYNE: No, we don't break them down that way. And in response to an interrogatory we did provide further definition around how we estimate what the flotation cost piece of it would be. And in my discussion with Mr. Rubenstein this morning --

MR. GARNER: But you don't actually do it in your evidence. In your evidence it's just a singular concept; is that right?

MR. COYNE: Right. We adopt the Canadian standard of 50 basis points for both.

MR. GARNER: But I guess, and I wasn't there and you were, and I don't really want to get into the BC commission, but they clearly themselves drew a distinction between those two concepts because in one sense they make an adjustment, in one sense they are very clearly denying a concept; correct? I mean, it's a plain reading of it, you know, of the thing.

MR. COYNE: Maybe you could just restate your question?

MR. GARNER: Well, let me instead put the question this way: In your mind is there any difference between these two concepts of flotation costs and financial flexibility?

MR. COYNE: Yes.

MR. GARNER: Okay. Now, you also mentioned this morning something that struck me, which was that flotation costs and financial flexibility, and you are putting them together, they're uniquely a Canadian concept, i.e. it's

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it's for distribution only in that case.

MS. ANDERSON: Distribution, thank you. So my last question gets into my trying to get my head around the recommendation on WACC applying to DVAs and CWIP. So, let's talk the DVAs in particular.

Yes, I get that it's a deferred cost on the balance sheet. Actually, under IFRS, I guess it does flow through, a flow-through, the statements; I will have to get up on my accounting, there.

But the nature of them, does that not matter, the nature of what those DVAs were? Most of them, and I know there's some that are capital related, but most of them are an operating expense, or the difference between a revenue and an expense of, like, a variance account. And I know you said the recommendation is only for things that last more than a year; I think you said short term should be the status quo. But I am trying to get my head around applying a WACC to something that was an operating initially, if it had been recovered in that year.

So, can you help me understand why you would get a profit on something that was a deferred operating cost?

MR. DANE: Sure. I mean, to your question about the short-term, long-term nature, we answered some interrogatories on that as well, and we recognize that there may be some practicalities there. So, while we still would -- our recommendation would be the WACC to DVAs, we recognize that there could be a differentiation, for example, between group one and group two, group one being more readily reconciled versus group two, et cetera.

But our focus is really on the commitment of capital by the utilities in those cases. And so, in the midst of a rate plan, they could be committing capital that they had to spend on those operating expenses. But then it gets hung up for a number of years, potentially, until it's dealt with in the next rate setting application.

So our focus is really on the fact that that capital is tied up for a longer period of time. And, as we say in our report, and I mentioned a few minutes ago, that's used with a -- that is done with a mix of debt and equity. And so tying those all together forms our recommendation about weighted average cost of capital return for those accounts.

MS. ANDERSON: Okay. And then just the other question was a clarification on, I think it was your slide 18, it mentions CWIP in rate base. And so, not AFUDC. Can you explain?

MR. DANE: In the quote?

MS. ANDERSON: Yes. It says rate base is defined as net plant, property, working capital and the construction, like CWIP, in rate base.

MR. DANE: Right. And I think that's specific to this quote where Bonbright is describing the concept between sources and uses of funds. And so I read this to be for those jurisdictions that allow CWIP in rate base --

MS. ANDERSON: Okay.

MR. DANE: -- whether you wouldn't earn a return, which is not the case here. So I think that's -- we didn't

EB-2024-0063 Interrogatory Responses

Ontario Energy Association (OEA)

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

INTERROGATORY

Reference:

Exhibit M2, p. 3

Question(s):

At page 3, Concentric states “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.”

a) Please confirm whether Concentric’s view is that the fair return standard is not met as a result only of Ontario’s equity ratios being lower than Concentric’s deemed peer group (comparable investment standard) and not as a result of failing the capital attraction standard or the financial integrity standard.

b) To the extent that a) is not confirmed (ROE’s fail multiple components of the FRS) please cite specific instances of Ontario utilities failing to attract capital on reasonable terms or being in danger of losing financial integrity, or any specific examples that Concentrics believe are likely to happen in the future.

Response:

a) Confirmed, to the extent that Ontario utilities historically have been able to attract capital on reasonable terms and financial integrity has not been a significant concern. The cost of capital, however, is a forward-looking concept, and equity ratios that do not meet the comparability standard will threaten the Ontario utilities’ ability to attract capital at reasonable terms going forward. Further, as the OEB stated on page 19 of the 2009 Decision, EB-2009-0084, all three requirements or standards of the fair return standard must be met, and none ranks in priority to the others.

b) Concentric is not aware of Ontario utilities failing to attract capital or being in danger of losing their financial integrity since the 2009 Decision; Concentric is not able to answer the second part of the question because it requires speculation about the future. Given the uncertainty due to the Energy Transition and other risk factors, Concentric cannot know if Ontario utilities will be able to attract capital and maintain financial integrity in the future, but our recommendations will place Ontario's utilities in a stronger position to do so.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, Figure 19, p. 71

Question(s):

Note this interrogatory has been asked by LEI

It is common practice for Canadian regulators to approve an adjustment for flotation costs and financing flexibility, with 50 basis points being the norm.

a) Other than it being common practice, please provide the empirical basis (with examples of actual utility flotation costs) for recommending 50 basis points associated with floatation costs.

Response:

Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock, as well as price discounts and premiums. In his text, New Regulatory Finance, Dr. Roger Morin cited a 1996 study by Lee et. al., which found that the average flotation costs for regulated utilities are equal to approximately 5% of the gross proceeds of the equity issuance, with smaller issues tending to have a higher percentage.[1] This is consistent with recent research by the Enbridge Treasury team, which found that the average flotation costs for a sample of Canadian and U.S. utilities were also equal to slightly more than 5% of the gross proceeds. Based on Concentric's prior analysis of flotation costs, the empirical study cited by Dr. Morin, and the recent Enbridge analysis, our view is that flotation costs for utilities are within a range from 2% to 10%, with an average of around 5%. This can be translated into basis points of ROE by adjusting the dividend yield in the DCF model. Using this method, if f flotation costs are equal to 5% of the gross proceeds of the equity issuance, then the adjustment to ROE would be approximately 25 basis points for companies like those in Concentric's North American combined proxy group. Flotation costs at the higher end of the range (i.e., 10% of the gross proceeds), would equate to

[1] Dr. Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 323.

an approximately 45 basis points adjustment. Concentric notes that the 50 basis point adjustment approved by Canadian regulators also includes financial flexibility.
In addition to an adjustment for flotation costs, Canadian regulators in most jurisdictions including Ontario have also typically included an adjustment for financial flexibility. This adjustment provides a small cushion so that the utility may continue to raise equity in challenging capital market conditions.

According to Dr. Roger Morin, utilities need the ability to attract capital even during "market breaks" because they have an ongoing obligation to serve. For that reason, he recommends providing the utility an additional allowance for financial flexibility during difficult market conditions, as follows:

> *The flotation cost allowance of 5% allows for both the direct flotation costs and market pressure component but does not contain an explicit allowance for market break.*
>
> ***
>
> *Such an allowance is desirable, however. If negative events should occur during the time period from announcement of a public issue to actual pricing, the price could fall below book value unless a sufficient margin is maintained. Compared to non-regulated companies, utilities do not possess the same latitude and discretion in accessing capital markets in view of their obligation to serve. They must access capital markets regardless of capital market conditions. Therefore, they have limited ability to time security issuances in order to avoid an adverse market break.*[2]

[2] Dr. Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 326.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, p. 7

Question(s):

Note this interrogatory has been asked by LEI

Concentric stated the following:

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.

a) Please elaborate on the above statement.

b) Please provide real-world examples of Ontario utilities being unable to compete for investment capital on a comparable basis with their North American peers.

Response:

a) As stated in Concentric's report, Exhibit M2, at 136, "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." Concentric's recommended minimum equity ratio of 45% is approximately halfway between current equity ratios for Ontario distributors and transmitters and their U.S. comparators, and thus falls short of parity.

b) Concentric's view is not that Ontario utilities have been unable to compete for investment capital with North American peers, but rather that the level of equity thicknesses in Ontario does not currently meet the comparable return standard of the Fair Return Standard and is thus not providing investors a comparable risk-adjusted return. With the strengthening of the Energy Transition and the significant level of capital that will be deployed, lower risk-adjusted returns will prevent

Ontario’s utilities from competing for investment capital on a comparable basis with North American peers with stronger balance sheets.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Association of Major Power Consumers in Ontario (AMPCO) / Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

On page 128, Concentric states (bold added for emphasis):

> *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.*

On page 129, Concentric states (bold added for emphasis):

> *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 term****s. 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.***

Question(s):

a) Given the importance of credit metric analysis noted in the second passage cited above, did Concentric attempt to provide any such analysis? If so, please file it. If not, please explain why not.

b) The second quote above from page 129 implies that Ontario deemed ERs need to be increased "to maintain financial soundness and to attract capital on reasonable terms." Please provide evidence to support the assertions that Ontario utilities are not financially sound, and/or are not able to attract capital on reasonable terms.

Response:

a) No. The question misses the point that Concentric is emphasizing the limitation of credit metrics in determining the rate of return on equity. In the report, p. 129, Concentric continues:

> 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.

b) Concentric's analysis and recommendations are focused on impacts to utility financial integrity and capital attraction on a forward-looking basis. Our analysis demonstrates that the authorized ROEs and deemed equity ratios for Ontario utilities do not currently meet the comparable return principle of the Fair Return Standard. Failure to provide a return on invested capital that is commensurate with returns on investments of similar risk will impair Ontario utilities' ability to attract capital on reasonable returns, which will also inhibit their ability to maintain financial soundness.

Ontario Energy Association (OEA)

Answer to Interrogatory from
Ontario Energy Board Staff (OEB Staff)

INTERROGATORY

Reference:

Concentric Report, pp. 152 & 155 & 156

Question(s):

Concentric agreed with LEI's recommendation for short-term DVAs (i.e., accounts that will clear within one year), but Concentric recommended that the OEB apply each utility's WACC to long-term DVAs.

Concentric suggested that long-term DVAs are balances that are to remain on utilities' balance sheets for more than one year. LEI did not differentiate between short-term and long-term DVAs.

Concentric recommended that the OEB apply the WACC to CWIP, for purposes of accruing carrying costs on construction balances. Concentric noted that from an implementation perspective, this approach is not burdensome because the WACC for each utility is readily available.

Concentric stated that 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. Concentric stated that 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.

Concentric further stated that 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.

a) Please provide Concentric's views on how it would define short-term DVAs from long-term DVAs.

b) Would Concentric view all Group 1 DVAs as short-term and all Group 2 DVAs as long-term?

c) In Concentric's view, when the Group 1 DVAs are not disposed and carry more than one year's balance, do these DVAs become long-term DVAs?

d) Please provide Concentric's views on the potential increased regulatory burden on the OEB and stakeholders upon the separation of short-term DVAs from longterm DVAs.

e) Regarding Concentric's recommendations that the OEB apply each utility's WACC to long-term DVAs and CWIP, which WACC does Concentric propose to be used? For example:

   i. Regarding the balances approved for disposition in IRM proceedings, is Concentric suggesting that the WACC from the utilities' last rebasing proceeding be used?
   ii. Regarding the balances approved for disposition in cost-based proceedings, is Concentric suggesting that the WACC from the utilities' current cost-based proceeding be used?
   iii. Regarding the balances accumulated in the CWIP account and carried forward to rate base in a cost-based proceeding, is Concentric suggesting that the WACC from the utilities' last rebasing proceeding be used?

f) Please explain further why using a debt-only approach for CWIP places Ontario utilities "at a relative disadvantage in the ability to attract equity capital."

<u>Response:</u>

a) The short-term/long-term distinction relies on the length of time between when costs/customer refunds are incurred/deferred and when they are recovered from customers. Concentric considers short-term DVAs to be those for which costs are deferred and cleared within one year, with long-term DVAs being those for which the period between deferral and clearance is longer than one year. On page 153, Concentric referred to short-term DVAs as those that "cleared within one year," and clarified in footnote 168 that "DVAs that clear within one year would be those that are disposed within 12 months of the deferral of costs." From a practical perspective, Concentric believes that, where available, it would also be reasonable to use the accounting definition of short-term versus long-term, whereby short-term DVAs reported on a utility's balance sheet generally represent amounts to be cleared within 12 months of the balance sheet date and long-term DVAs generally represent amounts to be disposed of beyond one year.

b) Concentric's recommendation is based on regulatory and corporate finance principles, and the application of the WACC to DVAs is most consistent with those principles, regardless of the type or timing of the deferral. Concentric recognizes, however, 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, and, as such, Concentric recommended that short-term DVAs be applied the prescribed interest rate. As such, Concentric's definition of short-term vs. long-term is not reliant on whether a DVA is a Group 1 or a Group 2 DVA.

Concentric recognizes, however, that for practical purposes few, if any, DVAs are accrued and recovered within one year. As such, under Concentric's recommendation, most, if not all DVAs would accrue carrying charges at the WACC, which would be most consistent with corporate finance and regulatory principles, as discussed in Concentric's report.

If the OEB, however, were to determine that it is appropriate to distinguish between DVAs that accrue carrying charges at the WACC versus at the prescribed interest rate, applying the prescribed interest rate to Group 1 DVAs and the WACC to Group 2 DVAs would provide a reasonable approximation of the short-term versus long-term distinction that Concentric has drawn in its report, and thus represent a reasonable alternative to Concentric's proposal. That approach, while not wholly consistent with the principles Concentric discussed in our report, would reflect better alignment with those principles as compared to the status quo.

c) See the response to part b).

d) Concentric does not believe there will be increased regulatory burden because under the status quo, utilities regularly update DVA carrying charge accruals based on changes in prescribed interest rates, changes in deferral balances, regulatory approvals or modifications, etc. Applying a different carrying charge rate to one set of DVAs versus another would only impact the inputting of the appropriate rate when determining the carrying charge amounts on that account. Both the prescribed interest rate and utility-specific WACC rates are readily available and auditable.

e) Concentric proposes that the most recently-approved WACC be used for calculating carrying charges on long-term DVAs and CWIP, and, when the WACC changes (whether through rebasing or in cost-based proceedings), that updated WACC be applied on a going-forward basis for future accruals, similar to the approach used for changes in prescribed interest rates.

f) Using a debt-only approach for CWIP places Ontario utilities at a relative disadvantage in the ability to attract equity capital because a debt-only approach puts Ontario utilities out of step with their U.S. and Canadian peers, with whom Ontario utilities compete for capital. Since a debt-only approach results in Ontario utilities not recovering their full costs of financing construction, jurisdictions that allow the accrual of financing costs at the WACC provide the opportunity to earn their actual cost of capital for financing these functions.

EB-2024-0063
OEB Webpages and Filing Requirements

Ontario Energy Board

Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications

Chapter 2

Cost of Service

December 15, 2022

2.2.2 Fixed Asset Continuity Schedule

The information outlined in Appendix 2-BA must be provided for each year, in Excel format.

Continuity statements and year-over-year variance analyses must be provided. Continuity statements must provide year-end balances and include any capitalized interest during construction and any capitalized overhead costs. Written explanations must be provided where there is a year-over-year variance greater than the applicable materiality threshold.

If continuity statements have been restated for the purposes of the application (e.g., changes in accounting standards or policies, or to reflect corrections in historical audited values), the distributor must provide an explanation for the restatement and also provide a reconciliation to the original statements.

The following comparisons must be provided:[11]

- Historical OEB-approved vs. historical actual (for the most recent historical OEB-approved year)
- Historical actual vs. preceding historical actual (for the relevant number of years)
- Historical actual vs. bridge
- Bridge vs. test year

The opening and closing balances of gross fixed assets and accumulated depreciation that are used to calculate the fixed asset component of rate base must correspond to the respective balances in the fixed asset continuity statements. In the event that the balances do not correspond, the distributor must provide an explanation and reconciliation. This reconciliation must be between the the opening and closing test year net book value balances reported on the Fixed Asset Continuity Schedule (Appendix 2-BA) and the balances included in the rate base calculation. Examples of adjustments that would be made to the fixed asset continuity schedule balances for rate base calculation purposes are the deduction of the amounts for Construction Work in Progress (CWIP), capital contributions, and Asset Retirement Obligations (AROs).

A distributor may include in-service balances previously recorded in deferral or variance accounts, such as renewable generation/smart grid related accounts, in its opening test year Property, Plant, and Equipment (PP&E) balances, if these costs have not been previously reviewed and approved for disposition, and if disposition is being requested in this application. This may result in opening balances not reconciling to the closing bridge year PP&E balances. In this situation, the distributor must clearly show in its

[11] ACM/ICM assets to be included in the in-service year

not be expected to be recorded in the account, unless otherwise directed by the OEB. However, further accounting guidance was issued for certain distributors who rebased and closed the variance account. The OEB confirmed that these distributors will be allowed to re-open the account.[55]

2.9.1.8 Disposition of Distributor-Specific Accounts

For any material, distributor-specific accounts requested for disposition (e.g., Account 1508 sub-accounts), the distributor must provide supporting evidence showing how the annual balance is derived and provide the relevant accounting order. For distributor-specific accounts requested for disposition that are not material, the distributor must provide a brief explanation for the account balance and the relevant accounting order.

2.9.2 Establishment of New Deferral and Variance Accounts

In the event a distributor seeks an accounting order to establish a new DVA, the distributor must file evidence demonstrating how the following eligibility criteria have been met:

- Causation: the forecast amount to be recorded in the proposed account must be clearly outside of the base upon which rates were derived.
- Materiality: the annual forecast amounts[56] to be recorded in the proposed account must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed or capitalized in the normal course and addressed through organizational productivity improvements.
- Prudence: the nature of the amounts and forecast quantum to be recorded in the proposed account must be based on a plan that sets out how the amounts will be reasonably incurred, although the final determination of prudence will be made at the time of disposition. For any costs incurred, in terms of the quantum, this means that the distributor must provide evidence demonstrating that the option selected represented a cost-effective option (not necessarily least initial cost) for ratepayers.

[55] As noted in the OEB's December 16, 2021 Order and associated Accounting Guidance for Wireline Pole Attachment Charges, many distributors have rebased their rates since the issuance of the Pole Attachment Report, and reflected an updated pole attachment charge in their underlying rate structure. The OEB confirmed that these distributors who closed the variance account will be allowed to re-open the account effective January 1, 2021 to record any revenue shortfall resulting from the pole attachment charge for 2021 and 2022 as set by the Order and from the pole attachment charge set under the Regulation for subsequent years, until their next rebasing.
[56] Capital related amounts would reflect the revenue requirement impact.

Prescribed interest rates | Ontario Energy Board (oeb.ca)

Prescribed interest rates

Applicable to the approved regulatory accounts of natural gas utilities, electricity distributors and other rate-regulated entities

On November 28, 2006, the Ontario Energy Board (OEB) approved a methodology to prescribe interest rates for the approved regulatory accounts under the Uniform System of Accounts for natural gas utilities and electricity distributors (EB-2006-0117). The prescribed interest rates also apply to the regulatory accounts of other rate or payment amounts regulated entities when authorized by the OEB to use these rates.

Up until Q3 2024, the prescribed interest rate for the OEB-approved deferral and variance accounts (DVAs) was equal to the Bankers' Acceptances three-month rate, plus a spread of 25 basis points. Since Q4 2024, the prescribed interest rate for DVAs has been based on the three-month T-bill rate, plus a 25 basis points spread, in accordance with the OEB letter, July 26, 2024 (EB-2024-0063).

The prescribed interest rate for the construction work in progress (CWIP) account is equal to the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate yield. The OEB, under contract, obtains this yield rate from PC Bond Analytics, a business unit of FTSE.

These prescribed rates are reviewed and updated each quarter. However, no change is made to the prescribed interest rate where the difference between the calculated rate and the previous quarter's OEB-prescribed interest rate is less than 25 basis points. That is, the previous quarter's OEB-prescribed interest rate is continued for the current quarter.

For each quarter commencing Q2 2006, the prescribed interest rates are shown in the table below.

Quarter by Year [1]	Approved Deferral and Variance Accounts Prescribed Interest Rate (3-month T-bill plus 25 basis points spread; prior to Q4 2024 Bankers' Acceptances 3-month rate plus 25 basis points spread was used)	CWIP Account - Prescribed Interest Rate (per the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate Yield [2]
Q4 2024	4.40 [4]	4.55

Cost of Capital Parameter Updates | Ontario Energy Board (oeb.ca)

Cost of Capital Parameter Updates

The OEB determines the values for the Return on Equity (ROE) and the deemed Long-Term (LT) and Short-Term (ST) debt rates for use in cost of service and custom incentive rate-setting (custom IR) applications. The ROE and the LT and ST debt rates are collectively referred to as the cost of capital parameters.

March 6, 2024 - The OEB has commenced a **generic proceeding** regarding cost of capital and other matters (EB-2024-0063)

Sector: Electricity
Natural Gas
Category: Applications/Filing
Last revised: October 31, 2023

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%	**Letter (Oct 31, 2023)**

EB-2024-0063 Undertaking J3.1

OEB Staff's Answer to Undertaking J3.1

Undertaking

Ref: EB-2024-0063 Oral Hearing, September 27, 2024 transcript, p. 1

OEB staff to provide a list of OEB decisions since 2009 dealing with equity thickness.

Response

Listed below are the OEB decisions issued since 2009 that address equity thickness, which is a complete list to the best of OEB staff's knowledge.

1. EB-2010-0008, Ontario Power Generation Inc., Decision with Reasons, March 10, 2011
2. EB-2011-0210, Union Gas Limited, Decision and Order, October 24, 2012
3. EB-2011-0354, Enbridge Gas Distribution Inc., Decision on Equity Ratio and Order, February 7, 2013
4. EB-2013-0321, Ontario Power Generation Inc., Decision with Reasons, November 20, 2014
5. EB-2016-0152, Ontario Power Generation Inc., Decision and Order, December 28, 2017
6. EB-2020-0150, Upper Canada Transmission, Inc., Decision and Order, June 17, 2021
7. EB-2020-0290, Ontario Power Generation Inc., Decision and Order, November 15, 2021, approval of settlement proposal; Settlement Proposal, July 16, 2021
8. EB-2022-0200, Enbridge Gas Inc., Decision and Order, December 21, 2023