Shepherd Rubenstein

Mark Rubenstein
mark@shepherdrubenstein.com
Dir. 647-483-0113

BY EMAIL and RESS

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

November 7, 2024
Our File: EB20240063

Attn: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: EB-2024-0063 – Generic Proceeding on Cost of Capital – SEC Final Argument

We are counsel to the School Energy Coalition ("SEC"). Attached, please find SEC's Final Argument in the above-captioned matter.

Shepherd Rubenstein P.C.

Mark Rubenstein

cc: Brian McKay, SEC (by email)
Intervenors email)

EB-2024-0063

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF a generic proceeding commenced by the Ontario Energy Board on its own motion to consider the cost of capital parameters and deemed capital structure to be used to set rates.

FINAL ARGUMENT OF THE SCHOOL ENERGY COALITION

November 7, 2024

Shepherd Rubenstein P.C.
2200 Yonge Street, Suite 1302
Toronto, Ontario M4S 2C6

Mark Rubenstein

Tel: 647-483-0113
Fax: 416-483-3305

Counsel for the School Energy Coalition

TABLE OF CONTENTS

1 OVERVIEW **3**
1.1 INTRODUCTION 3
1.2 BACKGROUND AND THE FAIR RETURN STANDARD 3
1.3 SUMMARY OF SUBMISSIONS 6
1.4 THE IMPACT OF PROPOSALS 8

2 PEER GROUPS **10**
2.1 OVERVIEW 10
2.2 CONCENTRIC PROXY GROUPS 10
2.3 NEXUS PROXY GROUPS 12
2.4 CLEARY AND LEI 13
2.5 IMPACT 14

3 RISK AND CAPITAL STRUCTURE **18**
3.1 OVERVIEW 18
3.2 ENERGY TRANSITION RISK 18
3.3 CLIMATE CHANGE AND CYBER SECURITY RISK 20
3.4 REGULATORY RISK 21
3.5 CAPITAL STRUCTURE 22

4 RETURN ON EQUITY **29**
4.1 OVERVIEW 29
4.2 CAPM 30
4.3 DCF 34
4.4 RISK PREMIUM 36
4.5 FLOTATION COSTS 37
4.6 SEC BASE ROE RECOMMENDATION 42
4.7 ANNUAL ROE FORMULA 43

5 SHORT AND LONG-TERM DEBT **45**
5.1 SHORT TERM DEBT 45
5.2 LONG-TERM DEBT 45

6 OTHER COST OF ISSUES **51**
6.1 PRESCRIBED INTEREST RATE ON DVA BALANCES 51
6.2 PRESCRIBED INTEREST RATE ON CWIP 52
6.3 IMPLEMENTATION 53
6.4 REVIEW, REPORTING AND MONITORING. 55
6.5 CLOUD COMPUTING 56

APPENDIX A – CONCORDENCE WITH ISSUES LIST **59**

APPENDIX B **61**

APPENDIX C **62**

1 OVERVIEW

1.1 *Introduction*

1.1.1 The Ontario Energy Board ("OEB") initiated a generic hearing on its own motion to consider the methodology for determining the cost of capital, as well as other related matters, to be used in setting rates for electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation.

1.1.2 The cost of utility equity and debt makes up a significant portion of the revenue requirement used to calculate rates (or payment amounts) charged to customers. SEC acknowledges that it is legitimate for utilities to include these costs in rates. However, a balance must be struck between the utility and customer to ensure that the cost represents a fair return on invested capital.

1.1.3 This is the first time in 15 years that the OEB has considered these issues on a sector-wide basis with input from affected parties. The OEB has benefited from hearing from four experts representing various parties and OEB Staff, both through written evidence and during a six-day oral hearing.

1.1.4 The School Energy Coalition ("SEC") submits that the evidence shows the proposals from some experts, including those representing utilities, recommend a return on equity ("ROE") and capital structure that would lead to a cost of capital neither fair nor reasonable. Their assessment of risk, and attempts to compare Ontario utilities with those in other jurisdictions, are fundamentally flawed.

1.1.5 SEC has proposed a number of recommendations that set a fair return, properly assess utility risk, acknowledge the impacts of the energy transition on different sectors, and correct several significant issues with the models and comparisons used by most experts. Additionally, SEC has addressed several other issues, including requests for clarification on existing policy, which would help ensure regulatory clarity.

1.2 *Background and the Fair Return Standard*

1.2.1 The OEB, in exercising its broad discretion to set just and reasonable rates, is required to ensure that a company has an opportunity to earn a fair return on its invested capital.[1]

[1] *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186, p.192-193

This represents the "amount investors require by way of a return on their investment in order to justify an investment in the utility."[2]The Supreme Court has stated that "to encourage investment in a robust utility infrastructure and to protect consumer interests, utilities must be allowed, over the long run, to earn their cost of capital, no more, no less." If this is not allowed, "[o]ver 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….. [t]his will harm not only its shareholders, but also its customers."[3] The "fair return" must be fair to both the utility and its customers.

1.2.2 The OEB has previously stated that a "fair return" (the "Fair Return Standard") is the return on capital that meets three standards: capital attraction, financial integrity, and comparable investment.[4]

1.2.3 The current proceeding marks the first time since 2009 that the OEB has undertaken a comprehensive review of cost of capital parameters. The resulting *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* ("2009 Report")[5] includes many important principles and conclusions, but should not be treated as sacrosanct. The 2009 Report was developed through a robust consultation process, but it did not involve a generic hearing process. That meant there was no interrogatory process, and the evidence was not tested in an oral hearing. Thus, conclusions that were reasonable then may no longer hold after the more thorough review in this proceeding. Further, there were a number of issues in this proceeding that the 2009 Report recognizes were not a primary focus of that earlier review.[6]

1.2.4 The OEB's current policy sets a generic ROE for all utility segments (electricity distribution, electricity transmission, natural gas utilities, and OPG) but assigns different deemed capital structures depending on specific risk profiles. Based on the base ROE and the annual adjustment formula approved in 2009, the OEB's current cost of capital

---

[2] *Ontario (Energy Board) v. Ontario Power Generation Inc*., 2015 SCC 44, para.16

[3] *Ontario (Energy Board) v. Ontario Power Generation Inc*., 2015 SCC 44, para.16, referencing *Transcanada Pipelines Ltd. v. National Energy Board*, 2004 FCA 149, para.13

[4] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.19

[5] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009

[6] The OEB said that the determination of both long and short-term debt, as well as capital structure was not a focus of the consultation. (Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.ii-iii, 50-51)

methodology results in an ROE of 9.25% for 2025.[7]

1.2.5 For electricity distributors, the deemed equity component of their capital structure (i.e., equity ratio or "thickness") has been set at 40% since at least 2006.[8] For electricity transmitters, natural gas utilities, and OPG, the 2009 Report determined that the deemed capital structure would be set on a case-by-case basis.[9] In practice, all electricity transmitters have simply adopted the 40% equity ratio used for distributors.[10]

1.2.6 For natural gas distributors, the OEB most recently set Enbridge Gas Inc.'s capital structure in 2023 with an equity ratio of 38%[11], while EPCOR Natural Gas LP's South Bruce service territory is set at 36%[12], and Aylmer service territory at 40%.[13] OPG's equity ratio was most recently set in 2021 at 45%.[14]

1.2.7 The experts in this proceeding have agreed that utility companies are relatively low-risk investments. Mr. Coyne from Concentric noted that Ontario's transmission and distribution companies are "a low-risk group of companies."[15] Dr. Cleary commented that "utility stocks are considered quality because of their high yield and relatively low-risk operations."[16] Similarly, Mr. Zarumba from Nexus affirmed that utilities "are a lower risk than the market as a whole."[17]

1.2.8 Ontario's utilities operate in an especially low-risk, regulated environment. According to S&P, the "[r]egulatory frameworks for electricity and gas transmission and distribution networks in Ontario exhibit characteristics that are consistent with our most credit-supportive (strong) regulatory advantage assessment."[18] Ontario utilities with third-party

---

[7] OEB Letter, 2025 Cost of Capital Parameters (October 31, 2024)

[8] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, p.5

[9] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.50, 59

[10] See for example, see Hydro One Transmission (EB-2021-0110, Exhibit F, Tab 1, Schedule 1, p.1-2)

[11] *Decision and Order* (EB-2022-0200), December 21, 2023, p.67

[12] See EB-2018-0264, Exhibit 5, Tab 1, Schedule 1, p.2. EPCOR South Bruce's currently approved base revenue requirement was determined using the Common Infrastructure Plan process which used a common approved capital structure based on the then Union Gas equity ratio of 36%.

[13] See EB-2024-0130, Exhibit 5, Tab 1, Schedule 1, p.9

[14] *Decision and Order* (EB-2020-0290), November 15, 2021, Schedule A, p.24

[15] Tr.2, p.169

[16] Tr.5, p.186

[17] Tr.4, p.187

[18] M2-0-SEC-32, Attachment 9

credit ratings are typically rated as investment-grade, in the broad "A" category.[19] In June, S&P upgraded Hydro One's credit rating to A, and just last week, Toronto Hydro's rating was raised to A+[20]

1.2.9 The evidence in this proceeding indicates that the existing ROE and deemed capital structures not only meet but exceed the Fair Return Standard. Ontario utilities can raise equity or debt today on terms[21], with no threat to their financial integrity.[22] Although there is considerable disagreement among the experts regarding whether the current parameters meet the comparable investment standard, SEC submits that a review of the evidence, when accurately presented[23], demonstrates a clear affirmative. The better view appears to be that the parameters are too high, when viewed on a proper risk-adjusted basis.

1.3 ***Summary of Submissions***

1.3.1 The positions of SEC as set out in this Final Argument can be summarized as follows:

1.3.2 ***Capital Structure.*** SEC proposes the following equity ratios:

- ***Electricity Distributors*** – 37% equity ratio
- ***Electricity Transmitters*** – 37% equity ratio
- ***Natural Gas Utilities*** –Determined on a case-by-case basis. No change to Enbridge's recently approved equity ratio of 38%.
- ***OPG*** – Determined as part of its next payment amounts proceeding.

1.3.3 ***Return on Equity.*** SEC proposes that the OEB set a generic ROE applicable to all utilities, except for OPG. OPG's unique circumstances as a generator, as well as having substantial and unique regulatory support mechanisms, require a more fulsome review that should take place as part of its next payment amounts proceeding.

1.3.4 The base ROE should be set at 7.58% based on the average of three methods: the Capital Asset Pricing Model ("CAPM"), the Discounted Cash Flow Model ("DCF"),

---

[19] See credit rating report included in attachment to M2-SEC-32 and those filed as Attachments to M3-10-SEC-72.
[20] See S&P Press Release: '[Toronto Hydro Corp. Upgraded To 'A+' Following Upgrade Of The City Of Toronto, Outlook Stable (October 30, 2024](#))
[21] Tr.2, p.184; Tr.3, p.61; Tr.5, p.6-8; M2-10-CME-1a
[22] Tr.3, p.61
[23] See for example, Tr.5, p.56

and the equity premium model. That average should be calculated using corrected inputs, including a more representative proxy group of the risks Ontario utilities face, and the equity premium model should be based on market data. The OEB should also exclude flotation costs from the calculation of the ROE, but allow utilities to record actual equity transaction costs in a deferral account to be recovered later.

1.3.5 SEC does not propose any changes to the adjustment formula used to derive the annual approved ROE, with the exception of updating the base values.

1.3.6 ***Flotation and Transaction Costs.*** Equity flotation costs should no longer be included as part of the OEB's ROE calculation. Instead, they should be recovered on an actual basis through a deferral account. In contrast, debt transaction costs should continue to be recovered as part of the interest expense, amortized over the term of the specific debt instrument using the effective interest rate method.

1.3.7 ***Deemed Long-Term Debt Rate.*** SEC recommends that the methodology for setting the Deemed Long-Term Debt Rate ("DLTDR") be revised to use the prevailing 30-year Government of Canada bond yield as an input, rather than using a forecast. SEC also requests that the OEB clarify several aspects of its existing policy regarding when the DLTDR should be applied

1.3.8 ***Short-Term Debt Rate.*** Since the current reference rate (the 2-month Bankers' Acceptance rate) used for setting the Deemed Short-Term Debt Rate ("DSTDR") has been discontinued, SEC agrees with other experts that the use of the 3-month Canadian Overnight Repo Rate Average ("CORRA") futures rate as a replacement is appropriate.

1.3.9 ***Implementation.*** The OEB should implement any changes to the ROE and capital structure for an individual utility at their next rebasing application, unless the utility is rebasing for 2025 rates and the adjustment is permitted or required under any approved settlement proposal.

1.3.10 ***Prescribed Interest Rate and CWIP.*** The OEB should maintain its current approach to setting the prescribed interest rate for both DVA balances and CWIP, with minor modifications. To address concerns regarding the methodology for CWIP being a barrier to Indigenous equity participation, the OEB should convene a dedicated process to look at regulatory, jurisdictional, and fairness issues that may arise.

1.3.11 ***Review, Reporting and Monitoring.*** A full review of the cost of capital parameters and methodology, through a generic hearing, should be undertaken every five years. In the interim, additional utility reporting, as recommended by SEC, is valuable for monitoring the reasonableness of current cost of capital parameters and determining if immediate action is required.

1.3.12 ***Cloud Computing.*** The OEB should apply the prescribed interest rate applicable to DVAs to the balances in the Cloud Computing DVA. There is no compelling reason for cloud computing costs to be treated differently from other costs included in a deferral or variance account.

1.4 *The Impact of Proposals*

1.4.1 The impact of each of the various proposals is very significant. The OEA/CLD+ estimate that the impact of the OEB implementing Concentric's recommendations for just the OEB and capital structure for their utilities, which does not include any change at this time for OPG, would be to increase the revenue requirements (and therefore rates) by approximately $460M a year. [24]. That amount is understated, since the utilities are using primarily 2023 rate base, which is lower than their approved or forecast 2025 rate base. The EDA (or Nexus) did not undertake any analysis when asked regarding the estimate of the additional costs they seek to recover from their ratepayers.[25]

1.4.2 The OEA/CLD+ estimate that if the OEB implements Concentric's recommendations for capital structure and ROE, for their utilities, which excluding any changes at this time for OPG, it would increase revenue requirements by approximately $460 million annually which would be recovered from ratepayers. This figure is likely understated, as it is based primarily on 2023 rate bases, which are lower than the utilities' approved or forecasted 2025 rate base. The EDA (and their expert Nexus) did not perform any analysis when asked to estimate the additional costs they seek to recover from ratepayers.

1.4.3 SEC has provided an estimate of the impact of each proposal by segment, based primarily on the PP&E values provided by OEB Staff in Undertaking J2.1, and by comparing the proposed ROE values against the OEB 2025 value (9.25%) based on the

[24] Tr.3, p.53; M2-19-SEC-57 (K2.6, p.310-312)
[25] Tr.5 p.60; M3-19-SEC-81 (K5.1, p.81)

existing methodology.[26]

Estimated Impact of ROE and Capital Structure Proposals ($M)					
	LEI	Concentric	Nexus	Cleary	SEC
Electricity Distribution	-50.5	235.7	249.9	-346.6	-284.5
Electricity Transmission	-33.5	156.3		-229.7	-188.6
Natural Gas Utilities	-30.0	177.5		-186.5	-136.2
OPG	-48.9			-284.8	

1.4.4 These numbers are understated due to the PP&E values being based on 2023 actuals. The LEI and SEC numbers also do not include the utility's recovery of actual equity flotation costs through different means as proposed by LEI (in operating costs) and SEC (through a deferral account).

[26] Detailed calculations included in Appendix B

2 PEER GROUPS

2.1 *Overview*

2.1.1 A major component of each expert's approach in recommending a base ROE and capital structure is the selection of peer or proxy group(s) of utilities.[27] The experts use data from these peer groups not only as a point of comparison with Ontario utilities, but also as inputs into their financial models. For example, each expert uses data from selected peer group(s) as input for their CAPM and DCF models.

2.1.2 The reason the experts use a peer group approach, as explained by Concentric, is that since the ROE is a market-based concept, it is necessary to establish a group of companies that are both publicly traded and comparable to Ontario's utilities in fundamental business and financial respects, to serve as a proxy for ROE estimation.[28] The key, then, is to ensure that the peer group utilities are, in fact, comparable to Ontario's utilities. SEC submits they are not.

2.1.3 Each of LEI, Concentric, and Nexus primarily uses U.S. companies as part of its peer group. In doing so, they are either explicitly or implicitly concluding that Canadian and U.S. utilities, and the jurisdictions they operate in, have comparable risks. Dr. Zarumba, on behalf of Nexus, testified that the U.S. utilities included in his proxy group and the individual jurisdictions they operate in were "similar" to Ontario.[29] Mr. Dane, on behalf of Concentric, found that they were "sufficiently similar."[30] The evidence suggests otherwise.

2.2 *Concentric Proxy Groups*

2.2.1 Concentric, who recommends that the ROE and capital structure of OPG should not be set as part of this generic proceeding due to its uniquely higher generation risk, includes numerous companies in its electric proxy group that have significant generation assets. Fifteen of the 19 companies in Concentric's North American Electric Proxy Group own generation assets.[31] The amount of generation assets owned by many of these proxy companies is substantial. For example, the proxy group includes companies such as

[27] The terms peer group and proxy group are used interchangeably.
[28] M2, p.45; Tr.2, p.150
[29] Tr.4, p.164
[30] Tr.3, p.51
[31] See Undertaking J3.2_Attachment 1, 'CEA-2 Proxy Group' tab

Alliant Energy[32], Southern Company[33], and Pinnacle West[34], where approximately half of their electricity assets are in generation. The level of generation assets is even higher for companies such as NextEra.[35] Additionally, a number of the proxy companies own relatively higher-risk generation assets, such as nuclear[36]and coal.[37]

2.2.2 In contrast, Ontario's electricity distributors and transmitters do not have material generation assets, if any at all, and none of those assets are regulated.[38] They are not comparable in risk to large U.S. vertically integrated utilities that own significant generation assets. As Concentric has previously stated, the "generation function is generally regarded by investors as being higher risk than electric transmission/ distribution."[39] Moody's, which Concentric cites, has said that "[g]eneration utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation," which it views as the "highest risk component of the electric utility business."[40]

2.2.3 This is why including companies with material generation assets is not appropriate if they are to be used to derive the cost of capital for Ontario's electricity distributors and transmitters. In fact, when Concentric is making cost of capital recommendations for companies that have generation assets, their approach is that each proxy group company must own generation assets.[41] When asked about this inconsistent approach, Mr. Coyne,

[32] Tr.2, p.156; K2.6, p.184
[33] Tr.2, p.166; K2.6, p.198
[34] Tr.2, p.166; K2.6, p.196
[35] Tr.2, p.194; K2.6, p.195 (43% of NextEra Florida Power and Light business, and 71% of its NextEra Energy Resources business, is made up of generation assets)
[36] Tr.2, p.160; For companies with nuclear assets see example: Ameren (K2.6, p.186), Duke Energy (K2.6, p.190), Entergy (K2.6, p.192), NextEra (K2.6, p.194), Pinnacle West (K2.6, p.196), Southern Company (K2.6, p.198), Xcel Energy (K2.6, p.200)
[37] Tr.2, p.160; For companies with coal assets see example: Ameren (K2.6, p.186), Duke Energy (K2.6, p.190), Xcel Energy (K2.6, p.200)
[38] Tr.5, p.9; Tr.2, p.152-154
[39] Tr.2, p.148-149; Concentric Report Prepared for Ontario Power Generation (EB-2020-0290, C1-1-1, Attachment 1), p.63 (K2.6, p.25)
[40] Tr.2, p.149; Concentric Report Prepared for Ontario Power Generation (EB-2020-0290, C1-1-1, Attachment 1), p.63 (K2.6, p.25)
[41] For example, when Concentric filed evidence supporting a change in capital structure for OPG, it has excluded utilities from its final proxy group that do not own regulated generation assets (Concentric Report Prepared for Ontario Power Generation (EB-2020-0290, C1-1-1, Attach 1), (K2.6, p.25), p.63). Similarly, when testifying on behalf of vertically integrated utilities before US state regulators, Concentric has included as a specific proxy criterion the ownership of generation assets (See for example, Direct Testimony of James M. Coyne on Behalf of Georgia Power Company, K2.6, p.230; Tr. 3, p.17).

on behalf of Concentric, rationalized it primarily on the basis that "if we were to screen on companies that were just pure-play [transmission and distribution] companies, there just aren't that many in North America to draw upon."[42] SEC agrees, but the solution is not to use primarily companies that have significantly higher risk, without any adjustment for that higher risk. As Dr. Cleary aptly put it regarding the other experts' peer groups build on the premise that a larger sample is better regardless of comparability, "comparing apples to more oranges doesn't help."[43] If anything, it all calls into question the ability to construct a peer group of utilities with similar risk to Ontario utilities, to which Concentric recommends the generic ROE should be applied.

2.2.4 Concentric's proxy group also includes several companies with material unregulated businesses[44], which are riskier than a fully regulated business like the utilities whose cost of capital is being determined in this proceeding.[45]

2.2.5 A closer examination of the U.S. companies in the Concentric proxy reveals that they differ significantly from Ontario utilities in other ways. While most U.S. companies have an investment-grade credit rating, it is generally lower than that of Ontario utilities.[46] Furthermore, unlike Ontario, where test years are fully forecasted, most U.S. electric utilities that are part of the holding companies included in the proxy group use either a historical or partially forecasted test year, increasing regulatory lag.[47] Additionally, only about have of the U.S. electric utilities have any form of revenue decoupled[48], and few offer anything close to the fully fixed distribution rates for their largest customer segment (residential customers), which the OEB has mandated in Ontario. [49]

2.3 ***Nexus Proxy Groups***

2.3.1 Nexus, whose cost of capital analysis and recommendations focused on electricity

[42] Tr.3, p.19
[43] M4-OEB Staff-67a
[44] Each of NextEra, AltaGas, Enbridge Inc. and Spire Inc. all have unregulated operations above 10% (See J4.2, Attachment 1, 'CEA-2 Proxy Group' tab.
[45] Tr.2, p.54
[46] M2-CCC-4, Attachment 1 (K6.2, p.138)
[47] M2-CCC-4, Attachment 2, p.3 (K6.2, p.139); Tr.4, p.40
[48] M2-SEC-51, Attachment 1 (K6.2, p.14-18)
[49] M2-SEC-51, Attachment 1 (K6.2, p.14-18); Of the 66 utilities only 6 have fully decoupled rates, and 31 have partially decoupled rates.

distributors[50], has an even worse proxy group. Not only does it primarily include vertically integrated utilities, like Concentric's proxy group, but it also includes several companies that even Nexus admits "could potentially be excluded."[51]

2.3.2 Nexus includes companies such as Otter Tail Corporation[52] and Alaska Power & Telephone Company[53], where at least half of their revenue and earnings come from non-electricity businesses (manufacturing/plastics and telecommunications, respectively). It also includes companies such as PG&E Corporation[54] and Hawaii Electric Industries[55], which, unlike any utilities in Ontario[56], include companies with credit ratings below investment grade. There are also other issues; for example, Nexus includes a company like AES Corporation, which does have some distribution operating companies, but they are all based in El Salvador.[57]

2.3.3 To put Nexus' proxy group in perspective, only 18 of its 43 peer companies would have passed Concentric's screening criteria, which, as SEC notes, is flawed as it includes vertically integrated companies.[58] A number of additional companies would not pass Concentric's screens of investment-grade, M&A activity, dividend, positive earnings growth, or operating income from electricity operations.[59]

2.4 ***Cleary and LEI***

2.4.1 SEC's concerns with the proxy groups used by LEI and Dr. Cleary are less acute because both experts recommend a generic ROE that would also apply to OPG. Therefore, the inclusion of vertically integrated utilities may be more reasonable.

2.4.2 Nevertheless, LEI's proxy group remains overly weighted towards generation. LEI organizes its proxy group utilities into three categories, generation, wires (electricity transmission and distribution), and gas distribution. As part of its financial models to establish an ROE, LEI weights these categories based on the relative Ontario rate base

---

[50] Tr.5, p.4-5
[51] Tr.5, p.17
[52] Tr.5, p.16-17; K5.1, p.14-15
[53] Tr.5, p.15-16; K5.1, p. 11-12
[54] Tr.5, p.20; K5.1, p.39
[55] Tr.5, p.21; K5.1, p.38
[56] Tr.5, p.20
[57] Tr.5, p.23; K5.2, p.31
[58] See Undertaking J4.3, Attachment 1
[59] See Undertaking J4.3, Attachment 1

of each segment.[60] The issue is that many companies in the wires category are vertically integrated and so are not truly wires companies.[61] Similarly, as with SEC's concerns about Concentric and Nexus, reliance on U.S. utilities raises similar comparability issues with Ontario utilities. LEI's generation proxy group also suffers from being made up of companies that are predominately unregulated, as opposed to rate-regulated like OPG.[62]

2.4.3 Dr. Cleary's proxy group consists entirely of Canadian companies.[63] However, it is small (only 5 companies) and several of these companies have substantial operations in the U.S. and other non-Canadian jurisdictions, again raising concerns about comparability.[64]

2.5 ***Impact***

2.5.1 The impacts on the financial model results due to these non-comparable peer groups are significant. For example, when Concentric re-ran its financial models, removing proxy group companies that owned generation assets, and had more than 10% of their income from unregulated operations, there was a 30 basis points ("bps") reduction in the forecast ROE.[65]

2.5.2 It is notable that in the 2009 consultation, unlike now, Concentric recognized the problem of comparing Ontario utilities to U.S. vertically integrated utilities and attempted to address it. It undertook an analysis to estimate the effect of generation on a utility's authorized ROE, and based on those results, it adjusted its electric proxy group ROE results downwards by 40 bps.[66]

---

[60] See for example M1, p.118-119, Figures 38 and 39

[61] Peer group includes vertically integrated companies such as Ameren Corporation (K2.6, p.186) , Edison International (See 2023 Financial & Statistics Report, p.11, First Energy (see website – About Us Page)

[62] M1, p.118; For example, LEI's 'generation segment' proxy group includes TransAlta, which has contracted and merchant generation, but not rate-regulated generation as does OPG (Tr.15, p.19; K5.1, p.17). Similarly, Innergex "mostly sell the generated power under long-term power purchase agreements, power hedge contracts and short- and long-term industrial contracts to rated public utilities or other creditworthy counterparties, or on the merchant market" (See Innergex 20023 Annual Report p.20). LEI refuses to provide detailed information for each of its proxy group companies including percentage of operating income that is regulated (See M1-5-CCC-6).

[63] M1, p.93

[64] See Tr.6, p.116-117

[65] Undertaking J4.2, Attachment 1

[66] See Comments of Concentric Energy Advisors Inc., on behalf of Enbridge Gas Distribution, p.C-3, C-4 (EB-2009-0084, Enbridge Gas Distribution Inc., Written Comments, September 9, 2009, pdf pages 100-101).

2.5.3 SEC also disagrees with the assumption that even pure electricity transmission and distribution utilities in Canada have similar risks to those in the U.S. As Fitch Ratings noted this past summer with respect to Alectra Utilities, its lower allowed ROE (8.95%) and equity ratio (40%) were "sufficiently offset by the OEB's track record of predictable regulatory support."[67] Similarly, S&P ranks Ontario in the highest of its five categories of credit-supportive jurisdictions.[68] This reflects the perspective of actual investors who continue to invest in Ontario utilities, even with comparatively lower approved ROEs and equity ratios. If they thought otherwise, it would be reflected in market data.

2.5.4 The OEB's 2009 Report recognized that identifying "enterprises of like risk" does not mean they are of the same risk.[69] At the same time, it noted that the "comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated entities."[70]

2.5.5 The AUC, faced with a similar problem, accepted that peer groups have comparability issues with the utilities it regulates. While it found they were sufficiently comparable for the purposes of the financial models, it recognized that Alberta utilities are "at the low end of the range of risk present in the comparator group" and that "a significant amount of judgment must be applied by the Commission when interpreting data from the representative utilities to establish the ROE required by investors in the Alberta utilities."[71] Quebec's Régie de l'énergie has also counselled caution when making comparisons to U.S. utilities.[72]

2.5.6 SEC does accept that there is an integrated Canadian-U.S. capital market, and that investors will look at both Canadian and U.S. companies to deploy their capital. As Dr. Cleary recognized, there is a home bias, and even on a risk-adjusted basis, Canadians are more likely to invest their capital in Canada, and U.S. investors in the U.S.[73] In a way, Concentric recognizes this; in its testimony on behalf of U.S. utilities, it never

[67] Fitch Affirms Alectra's IDR at 'A-'; Outlook Stable (Attachment to M3-10-SEC-72) (K5.1, p.41)
[68] M2-0-SEC-32, Attach 10, p.6 (K2.6, p.70)
[69] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.21
[70] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.21
[71] Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023), October 9, 2023, para. 104
[72] Régie de l'énergie, Decision D-2022-0119, October 26, 2022, para. 201
[73] Tr.5, p.194; Tr.6, p.192

includes Canadian companies in its proxy group.[74] It only compares U.S. companies with other U.S. companies. Since U.S. utilities generally have a relatively higher ROE compared to Canadian utilities, this inherently increases Concentric's recommended ROE. When adopted by the relevant U.S. regulator, this asymmetrically increases the comparative ROE with Ontario utilities.

2.5.7 Caution is also required when using allowed ROEs in the U.S. as a relevant point of comparison to Ontario utilities. For example, Concentric's evidence presents a chart comparing Ontario to other jurisdictions, showing that ROEs for electric utilities are materially lower in Ontario than in the U.S.[75] However, upon reviewing the underlying data it is revealed that the data primarily contain decisions for vertically integrated utilities. When only the allowed ROE's of distribution and transmission utilities are considered, the U.S. average ROE drops by 37 bps to 9.29%[76], which is very close to the OEB's current approved ROE of 9.21%.[77] In fact, the weighted OEB approved ROE over the same period as the U.S. data (January 1, 2023 to May 31, 2025) is actually higher at 9.32%.[78]

2.5.8 Moreover, U.S. regulatory decisions that set allowed ROEs are not always the product of strict financial modeling. Some are influenced by policy and other factors that the specific regulator believes are appropriate. For example, in a recent decision regarding Oncor Electric, even though an Administrative Law Judge recommended that the company's ROE be set at the mid-point of the reasonable range (9.3%), the Public Utilities Commission of Texas approved 9.7%, in part on the basis that it has broad "authority to consider the efforts of the utility in conserving resources, the quality of service, the efficiency of operations; and the quality of management."[79] Similarly, in late 2023, the Public Service Commission of Maryland approved a higher ROE for Baltimore Gas & Electric's (BGE) electricity distribution business compared to its natural gas business to "incentivize BGE, a dual fuel utility, to invest in its electric distribution system rather than gas distribution system," as a "reflection of a policy

---

[74] Tr.3, p.15; See for example Concentric proxy groups included in U.S. testimony (K2.6, p.232, 237, 248, 255, 276).
[75] M2, p.79l Tr.2, p.169
[76] Tr.2, p.171; M2-10-SEC-47b, Attachment 1 (Confidential)
[77] Tr.2, p.170; In fact the comparison to Ontario is even closer. The U.S. decisions that are used for the purpose of the comparison are between January 1, 2023 and March 31, 2024 (Tr.2, p.170).
[78] 9.32% = (12/17 * 2023 ROE of 9.36% + 5/17 * 2024 ROE of 9.21)
[79] Public Utilities Commission of Texas, Order No.4360 Oncor Electric Delivery, April 6, 2023, p.2 (K2.6, p.204)

shift."[80]

2.5.9 The evidence questions the suitability of current proxy groups for setting the ROE. Ontario utilities differ significantly from U.S. utilities, and there are too few publicly traded Canadian companies that are sufficiently comparable to Ontario utilities to serve as proxies.

2.5.10 As discussed later in these submissions, SEC proposes using a modified Concentric proxy group to address many of the major comparability issues. However, there is a compelling argument for the OEB to reject all proxy groups. Dr. Cleary's equity premium approach is the only model proposed by any expert that does not rely on one.[81]

[80] Public Service Commission of Maryland, Order No. 90948, Baltimore Gas and Electric, December 14, 2023, p.242 (K2.6, p.225)
[81] M4, p.105

3 RISK AND CAPITAL STRUCTURE

3.1 *Overview*

3.1.1 The OEB has traditionally addressed utility-specific risk as part of the deemed capital structure. Higher business and/or financial risk should be reflected in a higher equity ratio (or "thickness"), while lower risk should be reflected in a lower equity ratio.[82] The existing policy has been to reassess a utility's deemed capital structure when there are significant changes in business and/or financial risk.[83]

3.1.2 The OEB has reviewed the capital structure of OPG and Enbridge (and its predecessors)[84] multiple times since 2009, making changes as appropriate, but it has not done so for electricity distributors and transmitters. Since the OEB last broadly assessed the risks faced by utilities in setting the cost of capital either in 2006 or 2009, the evidence suggests that risks have decreased for electricity distributors and transmitters, while they have increased for natural gas distributors. For example, less than a year ago, the OEB increased Enbridge's equity ratio from 36% to 38% to account for the impacts of the energy transition.[85]

3.1.3 Since the OEB's last generic assessment of the cost of capital, there has been a decrease in the business and financial risk of electricity distributors and transmitters. When compared to Enbridge, a natural gas distributor facing increasing risk of stranded assets due to the energy transition, their risk is much lower and should be reflected by reducing their equity ratio to no higher than the level the OEB recently determined is appropriate for Enbridge. The relative risk between categories of utilities has now changed. While in the past, natural gas utilities may have been considered safer, due to changes in risk and regulatory developments in Ontario, that is no longer the case.

3.2 *Energy Transition Risk*

3.2.1 The most significant individual change in business and financial risk since the last time the OEB assessed the appropriate equity ratio for electricity distributors and transmitters is that driven by the energy transition. Contrary to the views of Concentric and Nexus,

---

[82] See *Decision with Reasons* (EB-2013-0321), November 20, 2014, p.113
[83] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.50
[84] *Decision and Order* (EB-2022-0200), December 21, 2023, p.61
[85] *Decision and Order* (EB-2022-0200), December 21, 2023, p.68

this results in a decrease, not an increase, in risk for the electricity sector. The energy transition will lead to a significant increase in electrification, which "serves as a boon to electric utilities, allowing them to increase electricity investments and sales."[86] While of course all change creates the possibility of uncertainty and therefore risk, growth on the electricity side provides a cushion that makes it easier for electricity companies to manage periods of change.

3.2.2 The OEB should reject Concentric's view that the energy transition will increase the risk for all types of utilities, and should not increase the equity thickness for electricity distributors, transmitters, and natural gas utilities to 45%. It cannot be that for natural gas utilities, the energy transition creates "a big risk… driven by customers shifting away from natural gas" [87], while at the same time, that shift to electricity also creates a significant risk that requires an increase in the proposed equity ratio for the electricity sector. It cannot be that both an increase and decrease in customers and volumes results in increased business risk. Unlike for natural gas utilities, there is little risk of stranded assets in electricity distribution or transmission. Quite the opposite. Electrification will lead to increased billing determinants, through higher customer numbers and demand.

3.2.3 While electrification will result in the need for increased capital investment, in a rate-setting system that remunerates utilities in part based on return on rate base, this will result in increased aggregate returns and net income.[88]As an example, Hydro One is currently promoting to investors that its rate base growth is specifically supporting its "attractive and growing dividends."[89] If anything, the energy transition, in the context of available investment opportunities as a whole, increases the attractiveness of electricity distributors and transmitters.

3.2.4 SEC agrees with LEI that for electricity distributors and transmitters to justify an increase, they would need to show that the energy transition is "making more volatile cash flows and profits of the regulated utilities and calling into question the recovery of their investments."[90] This is something they have not done, and the available evidence suggests otherwise.

[86] EB-2022-0200, Exhibit I.4.3, ED-146, Attachment, p.4 (K2.6, p.72)
[87] Tr. 2, p.122; M2-2-SEC-33, p.3 (K2.6, p.10)
[88] Tr.2, p.139
[89] Hydro One Investor Overview (Post Second Quarter 2024), p.11,23 (K2.6, p.116, 128)
[90] Tr.1, p.91

3.3 ***Climate Change and Cyber Security Risk***

3.3.1 Concentric points to the physical impacts of climate change and cyber security risk as two other significant drivers of increasing risk for electricity distributors and transmitters.[91] SEC accepts that these factors could increase risk, but the OEB has undertaken initiatives to mitigate this risk.

3.3.2 The OEB has been very active on the issue of cyber security. The OEB has developed a Cyber Security Framework that requires utilities to assess their cyber security maturity and readiness.[92] In recently adopted amendments to the Distribution and Transmission System Codes, the OEB requires compliance with new Ontario cyber security standards[93] and has announced an initiative requiring utilities to have a qualified third-party assess their cyber security maturity.[94]

3.3.3 With respect to the physical impacts on infrastructure resulting from climate change, the OEB has launched a wide-ranging consultation on the issue to establish a standard vulnerability assessment methodology, and to incorporate system hardening into distributor system planning processes.[95] Even without these mitigation activities, the only significant risk to electricity distributors would arise if there were no recovery of costs to replace damaged infrastructure from increased climate-related weather events. However, that is not the case, as every rate framework provides utilities access to Z-Factors[96], which allow incremental recovery of costs for unforeseen events[97], typically related to significant weather events.[98] Furthermore, increase in climate change risk in Ontario is nothing close to that faced by utilities in jurisdictions facing significant increases in wildfires[99] or hurricanes.[100]

---

[91] Exhibit M2, p.112, 121

[92] See for example, Ontario Cyber Security Framework (Version 1), December 6, 2017; See Notice of Proposal To Amend A Code: Proposed Amendments To The Transmission System Code and The Distribution System Code To Address Cyber Security for Electricity Transmitters and Distributors (EB-2016-0032), December 20, 2017

[93] Notice of Amendments to Codes To Enhance Cyber Security (EB- 2023-0173), March 27, 2024

[94] See OEB Letter, Re: Enhancing Cyber Security Readiness in Ontario's Electricity Sector, October 7, 2024

[95] See OEB Letter, Re: Vulnerability Assessment and System Hardening Project (EB-2024-0199), p.2 (K2.6, p.101)

[96] Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, p.13

[97] See, Filing Requirements for Electricity Distribution Rate Applications, Chapter 3, Incentive Rate-Setting Applications, June 15, 2023, p.22

[98] See for example, *Decision and Order* (EB-2023-0009), December 12, 2023, p.14; *Decision and Rate Order* (EB-2023-0113), March 21, 2024, p.9; *Decision and Order* (EB-2022-0317), June 15, 2023, p.5; *Decision and Rate Order* (EB-2022-0018), March 23, 2023, p.14

[99] See for example, Utility Drive: Nearly 100 utilities' credit ratings downgraded since 2020 as wildfire risks grow (October 2023, 2024)

3.4 ***Regulatory Risk***

3.4.1 Since the OEB last assessed electricity distributors' and transmitters' risks, the OEB has made significant changes to regulatory policy and mechanisms that have reduced business and financial risk. LEI, which reviewed only a subset of these changes, commented that "they have generally reduced the risks for electricity distributors."[101] LEI reviewed what it considered major policy changes, including the introduction of the Renewed Regulatory Framework for Electricity ("RRFE") (i.e., adoption of the current rate-setting frameworks), rate design for electricity distributors (i.e., moving to a fully fixed residential rate), the Framework for Energy Innovation, and the policy related to the establishment and clearance of DVAs.[102] In their view, each of these new policies has, in almost all cases, reduced uncertainty, increased flexibility, or provided compensation for changes in risk.[103]

3.4.2 LEI understates the reduction of risk, as it was instructed to review only what it considered major policy changes.[104] LEI did not consider other significant policy changes that have demonstrably reduced electricity distributor risk. In just the last 10 years, these include, among others: i) the introduction of the Advanced Capital Module (ACM), which gives utilities greater certainty of cost recovery[105], ii) the reduction of the ACM/ICM deadband from 20% to 10%[106], as well as the expansion of ICM eligibility for utilities on a deferred rebasing period, both of which increase the amount eligible for incremental cost recovery[107], iii) the increase in the MAADs deferred rebasing period from 5 to 10 years, at the discretion of the utility, allowing it to retain merger savings for a longer period[108], and iv) the annual update to LV Rates through the IRM/rate adjustment process (previously updated only at rebasing[109]), along with UTRs being issued in the year, allowing for more up-to-date RTSRs in annual rate adjustment

---

[100] See for example, Concentric's evidence filed on behalf of Florida Light & Power where Dr. Coyne discusses the prevalence of hurricanes as leading to high severe weather risk (K2.6, p.263).
[101] M1, p.74
[102] M1, p.64-70
[103] M1, p.64
[104] M1-3-SEC-11, p.2; Tr.2, p.61-65
[105] Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (September 18, 2014)
[106] Supplemental Report: New Policy Options for the Funding of Capital Investments (Jan 22, 2016)
[107] OEB Letter Re: Incremental Capital Modules During Extended Deferred Rebasing Periods (Feb 10, 2022)
[108] Report of the Board Rate-Making Associated with Distributor Consolidation (March 26, 2015)
[109] See Updated Filing Requirements for Electricity Distribution Rate Applications, Chapter 3 (June 15, 2023)

applications[110], both of which reduce regulatory recovery lag.

3.4.3 SEC believes that Concentric has significantly understated the impact of these regulatory changes. Even Concentric acknowledges that the OEB's policies have reduced electricity distributor risk. Concentric's own review of the individual policy changes identified by LEI, and those identified by SEC resulted, on balance, in a modest reduction of risk.[111]

3.4.4 The policies the OEB has undertaken to reduce regulatory lag are quite significant. S&P noted the "OEB's proactiveness to quickly address this regulatory lag as constructive and consistent" [112] and that "[w]ith this reduced lag in recovering higher transmission costs, we expect LDCs will be able to boost their financial measures."[113] It is one of the reasons why, from their perspective, the Ontario regulatory environment remains unchanged at the "most credit supportive" level.[114]

3.4.5 Much of the evidence on electricity risk changes focused on distributors, but the risk for electricity transmitters is, if anything, even lower. As LEI commented in its report, "[t]he risk profile of electricity transmitters is similar to, if not lower than, that of electricity distributors."[115] This is due to transmitters receiving the same benefit of increased electrification, while also benefiting from pooled cost recovery through the UTRs, and being less affected by pressures (both regulatory and otherwise) related to new customers.

3.5 ***Capital Structure***

3.5.1 Even after reaching such a conclusion, LEI does not propose any change in the equity ratio of electricity distributors and transmitters as part of this proceeding. It recommended that the OEB maintain what it describes as its "current approach of revising the capital structure upon application if warranted due to increase in business/financial risks",[116] calling it a reasonable practice. SEC disagrees with LEI's

---

[110] OEB Letter, 2024 Preliminary Uniform Transmission Rates and Hydro One Sub Transmission Rates (September 28, 2023)
[111] M2-3-SEC-34 (K6.2, p.92-94); Tr.2, p.126
[112] S&P, Windsor Canada Utilities Ltd. Outlook Revised To Stable From Negative On Regulatory Developments; Ratings Affirmed, June 18, 2024 (K6.2, p.57)
[113] M2-0-SEC-32, Attachment 10, p.6 (K2.6, p.71)
[114] M2-0-SEC-32, Attachment 10, p.6 (K2.6, p.71)
[115] M1, p.143
[116] M1, p.140

proposed asymmetrical approach.

3.5.2 First, while the practice for Enbridge (and its predecessors) and OPG has been to bring forward requests to change capital structure as part of their specific rate applications, that has not been the case for electricity distributors and transmitters. Such an approach might work for the largest distributors and transmitters, but it makes little sense and does not promote regulatory efficiency if applied to all other utilities. SEC had expected that, as part of this proceeding, the OEB would assess the capital structure of electricity distributors and transmitters.

3.5.3 Second, based on LEI's proposal, it would be up to the applicant to bring forward a proposal to adjust their capital structure when there is an increase in business and/or financial risk. This asymmetrical approach is unfair to customers. There is no requirement for a utility to seek an adjustment to their capital structure when those risks decline.

3.5.4 ***Electricity Distribution and Transmission.*** Electricity distribution and transmission ratepayers have been waiting a long time for the deemed equity ratio to be re-examined. In the meantime, they have borne the burden of higher rates and costs because of various regulatory initiatives that have reduced regulatory risk. While credit rating agencies have increasingly said that Ontario utilities operate in a "supportive regulatory environment"[117], that simply means that the regulator has allowed the shifting of risk and costs onto ratepayers.[118]

3.5.5 SEC submits that the OEB has sufficient evidence in this proceeding to lower the equity ratio of electricity distributors and transmitters 37%**.** If the OEB feels that more information is required, such as a cash flow analysis as LEI suggests[119], then it should initiate a second phase of this proceeding to obtain that information.

3.5.6 Dr. Cleary provided a detailed analysis of Hydro One's capital structure and recommends that its equity ratio, for transmission and distribution, be reduced to 38%,

---

[117] See for example, M2-0-SEC-32, Attachment 9; M2-10-SEC-41, Attachment 4, p.157; M2-10-SEC-41, Attachment 1, p.94.

[118] See for example, Moody's defines credit supportive regulatory frameworks as "the extent to which the regulatory formula is supportive of cost recovery, including the mechanism by which one-off costs or over-spends are recovered, if at all. In other words, it focuses on the risk allocation between the network operator and its customers." (See M2-0-SEC-32, Attachment 4, p.10)

[119] M2-2-VECC-17a (K2.6, p.88)

and further down to 36% over the following 2-3 years.[120] He analyzed Hydro One's credit rating, cost of debt, achieved ROE, financial risk, and credit metrics, and determined that the company's equity ratio could be as low as 36% and "still allow it to borrow and issue equity at attractive rates, as well as maintain solid credit metrics."[121] SEC agrees with his persuasive analysis of the financial impact of a reduction in the equity ratio, which confirms that, based on the reduction in business and financial risks, a reduction to 36% is appropriate and would not cause harm.

3.5.7 Only Concentric proposes an increase to the equity ratios. The OEB should be skeptical of Concentric's recommendations on capital structure, as its evidence in this proceeding is inconsistent with evidence it filed in other Canadian jurisdictions.

3.5.8 Last year in Newfoundland, Concentric filed a report recommending Newfoundland Power's equity ratio be increased to 45%, the same as it recommends in this proceeding, even though the stated rationale would not apply to Ontario.[122] For example, Concentric argued that the increase was needed to maintain certain credit ratings (an A rating from DBRS and Baa1 from Moody's), which were already lower than Hydro One's existing rating.[123]It also argued that Newfoundland faces risks due to weak macroeconomic and demographic conditions, neither of which are present in Ontario.[124] It also argued there was limited potential for customer growth in Newfoundland, whereas in Ontario, significant population growth is expected.[125]

3.5.9 In early 2023, in Alberta, Concentric proposed, on behalf of ENMAX, an increase to the equity ratios for electricity distributors and transmitters, increasing the equity ratio to 40% (rejected by the AUC[126]) to align with "the deemed equity ratios of comparable-risk electric utilities in Ontario."[127] Yet, now it proposes an increase to 45%, 5% higher

---

[120] M4, p.114
[121] M4, p.119
[122] M4-0-SEC-82
[123] M4-0-SEC-82
[124] Tr.3, p.153-154; M4-0-SEC-82
[125] M4-0-SEC-82. When asked about this oral hearing, Mr. Coyne did not recall discussing issues around electric load growth in demand (See Tr.3, p.154). A review of the Concentric evidence on behalf of Newfoundland Power demonstrates they did comment on customer growth in their risk analysis saying, "there are limited opportunities for customer growth in the Company's service territory, although electrification is expected to contribute to higher use per customer. " (See Cost of Capital Report, Prepared for Newfoundland Power Inc., p.70).
[126] Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023), October 9, 2023, p.64
[127] M4-CCC-1

than existing Ontario approved equity ratios, and 8% higher than the approved Alberta utilities equation ratios.

3.5.10 SEC anticipates that some parties representing affected utilities may argue that a reduction, as recommended, could be viewed negatively by the market. The OEB must carefully consider such assertions from utilities. Investors and the market typically seek higher returns through increased ROE and equity ratios, and they are understandably resistant to any measures that could reduce these returns. Thankfully, their preference is not how the OEB determines what is a "fair return".

3.5.11 Since 2009, the AUC has gradually reduced equity ratios for gas utilities (from 41% to 38%[128]) and more sharply for electric utilities (from 40.5% to 37%)[129], without inhibiting reasonable-term investments in the sector. No evidence has been produced to suggest otherwise. In fact, just last year, the AUC reaffirmed the appropriateness of the current equity ratios, which for electric utilities are significantly below those in Ontario, and rejected requests from utilities for increases.[130]

3.5.12 SEC recommends an equity thickness for both electricity distributors and transmitters of 37%. This would reflect their decreasing risks since it was last reviewed, and represent a modestly (1%) lower risk relative to natural gas distributors. While this level is still higher than the 36% justified by Dr. Cleary, it would have the advantage of being the same equity ratio as the AUC has set for Alberta electric utilities.

3.5.13 ***Enbridge.*** The OEB should reject Concentric's proposal to increase the equity thickness for Enbridge. As part of Enbridge's rebasing proceeding that occurred just last year, the OEB considered the issue of Enbridge's capital structure in significantly greater detail than in this proceeding, and determined the appropriate level was 38%.[131] The OEB heard from four different experts, including Concentric, LEI, and Dr. Cleary, who focused on this topic and considered it in the context of the company's overall application.[132]

---

[128] For all but one utility, Apex Gas Inc, who have unique circumstances, the equity ratio for gas utilities in Alberta is 37%. (See Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023), October 9, 2023, p.45, 62-65).

[129] M2-12-SEC-54, Attachment 1 (K2.5, p.5)

[130] Alberta Utilities Commission, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023), October 9, 2023, p.45, 64

[131] *Decision and Order* (EB-2022-0200), December 21 2023, p.67

[132] *Decision and Order* (EB-2022-0200), December 21 2023, p.62-63

3.5.14 In fact, it is telling that just a year ago, Concentric proposed an equity thickness for Enbridge of 42%[133]. With no evidence of any increase in risk since then, it now proposes 45%.

3.5.15 If anything, Enbridge's risk has decreased as a result of the passage of Bill 165, which was strongly endorsed by the company and is indicative of government support for natural gas.[134] This was followed up in late October with the release of the government's energy vision document which discussed the "need for an economically viable natural gas network to support a gradual energy transition, to attract industrial investment, to drive economic growth, to maintain customer choice and ensure overall energy system resiliency, reliability and affordability."[135]

3.5.16 The OEB's decision to increase Enbridge's equity thickness to 38% was also linked to several additional requirements for the company, including conducting a risk assessment and developing an approach to reduce stranded asset risk, to be filed with its next rebasing. [136] None of this analysis has been completed to date, nor was it included in Concentric's evidence.

3.5.17 ***OPG.*** SEC agrees with Concentric that the OEB should assess the appropriate capital structure and ROE for OPG separately, as part of its next payment amount proceeding.[137] OPG faces unique risks unlike any of the other utilities the OEB regulates, as a company whose regulated business is entirely generation. OPG is also beginning construction of new nuclear facilities (Small Modular Reactors) and planning for the refurbishment of the Pickering B Generation Station.[138]

3.5.18 At the same time, OPG has received unprecedented regulatory support compared to any other OEB-regulated utility, and likely any utility in North America. Ontario Regulation 53/05 provides OPG with numerous deferral and variance accounts that ensure it can recover prudent costs (and in some cases, firm financial commitments) related to, among other things, nuclear development[139], new capacity and refurbishments[140], the

[133] M2-12-SEC-53 (K2.6, p.19)
[134] Bill 165, *Keeping Energy Costs Down Act, 2024*
[135] Ministry of Energy and Electrification, *Ontario's Affordable Energy Future: The Pressing Case for More Power*
[136] *Decision and Order* (EB-2022-0200), December 21, 2023, p.67-68
[137] M2, p.10
[138] See for example, N-M2-0-SEC-32, Attachment 6, p.1
[139] O.Reg 53/05, s.5.4

Pickering B extension[141], and nuclear decommissioning liabilities.[142] There is no similar regulation for other utilities. In addition, the Government, which is also the sole shareholder, has signalled increased support for OPG[143] and nuclear more broadly. [144]

3.5.19 The impacts of both OPG's unique risks, balanced by the extensive regulatory protections and support, require a more fulsome consideration as part of the company's next payment amounts proceeding.

3.5.20 ***Single vs. Multi-Asset Transmitters.*** LEI recommends that there not be any difference in equity ratios between multi-asset and single-asset transmitters.[145] Concentric makes a similar recommendation, although it suggests that a differential could be appropriate, and should be proposed and supported as part of a utility-specific rate application.[146]

3.5.21 SEC does not support a relative increase in the equity ratio for single-asset transmitters compared to multi-asset transmitters. If anything, single-asset transmitters have lower risk, and should be accorded a slightly lower equity ratio.

3.5.22 There are a few reasons for this assessment.

3.5.23 First, transmitters receive a proportionate share of all transmission revenue based on their share of the revenue requirement, included in the calculation of the UTRs.[147] This has the effect of socializing demand and revenue risk across the entire transmission system, which, for single-asset transmitters, who make up a relatively small portion of the total UTRs, provides a disproportionate risk reduction benefit. [148]

3.5.24 Second, single-asset transmitters in Ontario are a relatively new phenomenon, and have

---

[140] O.Reg 53/05, s.6(2)4
[141] O.Reg 53/05, s.5.7
[142] O.Reg 53/05, s.5.2(1)8
[143] See for example, Ministry of Energy and Electrification News Releases: Province Investing in Hydroelectric Energy in Eastern Ontario (June 27, 2024), Ontario Refurbishing Hydroelectric Station in Cornwall (May 10, 2024), Ontario Refurbishing Hydroelectric Stations in Niagara (April 16, 2024)
[144] For example, under the recently introduced, Bill 124, *Affordable Energy Act, 2024*, if enacted, would include as one of the goals and objectives of an integrated energy resource plan, "prioritization of nuclear power generation to meet future increases in the demand for electricity in a manner that is consistent with the policies of the Government of Ontario."[emphasis added]
[145] M1, p.143-144
[146] M2, p.120
[147] Tr.2, p.56

newer assets compared to existing multi-asset transmitters. The benefit of this is that, at least at this stage in the lifecycle, they will have lower maintenance and replacement costs, as well as lower operating risk.[149]

3.5.25 Finally, the circumstances of single-asset transmitters in Ontario needs to be considered. Most of the existing single-asset transmitters in operation[150], or those planned for development or construction, are or will be majority-owned by Hydro One. [151] Hydro One has a commendable policy of offering up to 50% of the equity to Indigenous communities for new large transmission lines, which for practical purposes is implemented through the creation of a separate legal owner.[152] However, from the perspective of the broader market, the asset is still backed by Hydro One. An indication of this is that Hydro One Inc. allocates a portion of its debt issuances to its single-asset transmitters in which it holds an equity interest.[153]

---

[148] Tr.2, p.56
[149] Tr.2, p.57
[150] B2M LP, Niagara Reinforcement LP
[151] Chatham x Lakeshore LP, Waasigan Transmission Line, and St. Clair Transmission Line
[152] Hydro One launches industry-leading 50-50 equity model with First Nations on new large-scale transmission line projects (September 22, 2022)
[153] For example, B2M LP is allocated a portion of a larger Hydro One Inc. debt issuance (See EB-2024-0116, Interrogatory Response SEC-7)

4 RETURN ON EQUITY

4.1 *Overview*

4.1.1 LEI proposes a base ROE of 8.95%[154], which, when updated with the latest market data as of the end of September, is 8.88%.[155] This proposal reflects the average estimate of its CAPM model, and would apply to all regulated utilities, regardless of type.

4.1.2 Dr. Cleary proposes a base ROE of 7.05%, which, when updated with the latest market data as of the end of September, is 6.95%, which would be applied to all regulated utilities. This estimate is based on the average of his CAPM, DCF, and risk premium models.[156]

4.1.3 The utility experts' proposals are significantly higher. Concentric proposes a base ROE of 10%, applicable to all regulated utilities except OPG.[157] Its proposal reflects the average of three different model outputs, CAPM, DCF, and a risk premium model.[158]

4.1.4 Nexus proposes a base ROE of 11.08%, based on a weighted average of its CAPM, DCF, and risk premium models, considered only in the context of electricity distributors.[159]

4.1.5 LEI is the only expert basing its ROE recommendation on a single financial model, CAPM. Other experts incorporate multiple models, including a version of the DCF model and a risk premium approach. While SEC agrees that using multiple models is generally preferable, this assumes that the other models are fundamentally sound. As discussed further, SEC has significant concerns with the DCF model and specific risk premium approaches used by Concentric and Nexus.

4.1.6 Both CAPM and DCF are heavily influenced by the specific proxy group uses. As detailed in section 2, the proxy groups used by several of the experts consist primarily

[154] M1, p.122, 176
[155] Undertaking J2.2
[156] Undertaking J5.3, p.3
[157] M2, p.10; Concentric says that its ROE would apply to all utilities, but OPG should bring forward a proposal for an additional risk premium to be added to the generic ROE as part of its next payment amounts proceeding. Thus the generic ROE does not really apply to OPG as Concentric is recommending that they seek an amount above and beyond the 10% proposal.
[158] M2, p.10
[159] Tr.5, p.3-4

of U.S. companies, many of which are vertically integrated, include substantial unregulated business segments, and have fundamentally different risk profiles from Ontario utilities. This significantly impacts the results, and leads to ROE results that are higher than appropriate.

4.2 ***CAPM***

4.2.1 CAPM calculates ROE by adding a utility risk premium to a risk-free rate. This utility risk premium is calculated by multiplying beta, a measure of asset risk relative to the overall market, by the market risk premium ("MRP"), which represents the average return above the risk-free rate that investors typically require.[160]

4.2.2 SEC has several concerns regarding the inputs used by experts in their CAPM models.

4.2.3 ***Risk-Free Rate.*** Each of the approaches used by LEI, Concentric, and Nexus to estimate the risk-free rate is flawed, resulting in a materially higher rate than appropriate.

4.2.4 Concentric forecast 30-year Canadian and U.S. Government bond yields.[161] SEC agrees with Dr. Cleary that actual prevailing 30-year bond yields should be used, as they reflect what investors today consider risk-free and are therefore more accurate. CAPM is designed to represent the return an investor requires today, and prevailing bond yields are more accurate than forecasted bond yields.[162] Concentric itself acknowledges this by noting that the DLTDR, which is partially based on a long-term bond yield forecast ("LCBF"), has on average been 40 bps higher than actual Canada A-rated utility long-term bond rates.[163]

4.2.5 Nexus estimates the risk-free rate by forecasting only U.S. Treasury 30-year bond yields.[164] It uses the same flawed approach by using a forecast as opposed to prevailing 30-year bond yields, and relies solely on U.S. Treasury bond yields, which are 76 bps higher than 30-year Government of Canada bond yields.[165] Given that this proceeding is for setting the ROE for Ontario utilities, the risk-free rate should ideally be based entirely on Government of Canada bond yields.

---

[160] See M1, p.116-117
[161] M1, p.111; M2, p.64
[162] M4-0-SEC-82, p.3; M4, p.32-33
[163] M2, p.35-36
[164] M3-VECC-24b; M3, p.62, fn 81
[165] M4-0-SEC-83, p.2

4.2.6 LEI correctly uses a risk-free rate based solely on a forecast of the 30-year Government of Canada bond yield.[166] However, as discussed further in section 5.2, a more accurate estimate is using the using the actual 30-year Government of Canada bond yield as proposed by Dr. Cleary.[167]

4.2.7 ***Betas.*** SEC has several concerns with the beta estimates used.

4.2.8 First, to calculate beta, each expert examined the betas of companies in their respective proxy groups[168] or a historical trend for utilities more broadly.[169] Since CAPM beta is intended to represent the relative risk of a company (or, in this case, a class of companies) compared to the market as a whole[170], it is essential that each expert's proxy group accurately reflects the risk of the companies to which the ROE is meant to apply.

4.2.9 As discussed earlier, SEC disagrees with the appropriateness of most experts' proxy groups, as they do not provide a reliable measure of relevant utility sector risk relative to the market, and are likely overstated. LEI and Concentric's peer groups are heavily weighted toward U.S. (vertically integrated) utilities, which are generally riskier and have higher betas than Canadian utilities.[171] For reasons previously discussed, Nexus' proxy group is even less suitable. Each of these experts' proxy groups includes companies with risk profiles that do not reflect those of most utilities regulated by the OEB. Dr. Cleary's proxy group better reflects Ontario utility risk, as it consists solely of Canadian companies.[172]

4.2.10 Second, LEI's beta estimates rely solely on current beta values, which are unreliable due to their volatility.[173] This is evident in the significant discrepancies between the 1-year, 3-year, and 5-year beta estimates of LEI's peer group utilities.[174] A longer historical timeframe should be applied to produce a more stable estimate. In contrast,

[166] M1, p.119
[167] M4, p.38
[168] M1, p.118; M2, p.66; M3, p.66
[169] Dr. Cleary did not use his proxy group to directly determine his beta estimate 0.45, but used it to inform the accuracy (See M4-CCC-7a)
[170] M3, p.64
[171] M4, p.33, 35; For US versus Canadian utility betas, see M4, p.93
[172] M4, p.39
[173] M4, p.35
[174] M1, p.119, Figure 40

Dr. Cleary uses an average of 7-year weekly and monthly betas for his proxy group, which he then averages with a long-term utility beta estimate.[175] This is a more rigorous approach.

4.2.11 Third, Concentric and Nexus use adjusted rather than raw betas. The rationale for using adjusted betas assumes that, over time, company betas will trend toward 1 (the market average), necessitating an adjustment.[176] However, as Dr. Cleary's evidence conclusively demonstrates, utility betas do not trend toward 1.[177] This finding is supported by both academic literature and Dr. Cleary's detailed analysis.[178]

4.2.12 ***MRP.*** The experts' approaches to calculating the MRP differ. Based on the individual methodologies, SEC has a concern with the MRP estimate by LEI and both the utility experts, which appear to be inaccurate and overstated.

4.2.13 LEI relies solely on U.S. market returns to calculate its MRP, asserting that U.S. returns better reflect investors' expectations of equity returns.[179] However, LEI's stance lacks supporting analysis, and is based primarily on an 'after-the-fact' observation, as it found an "unreasonably low" CAPM ROE (5.14%) when using only Canadian market data.[180] To justify its conclusion, LEI notes that major Canadian pension funds allocate only about 25% of their portfolios domestically, interpreting this as evidence that investors base MRP opportunity costs on U.S. rather than Canadian MRP. [181]

4.2.14 This approach is flawed. It is inaccurate to assume that Ontario utility investors disregard Canadian market returns. Given the smaller size of the Canadian market, it is significant that major pension funds, collectively managing over a trillion dollars, allocate 25% domestically.[182] As previously discussed, while Canadian, U.S., and global capital markets are integrated, a home bias in investment still exists. Canadian investors hold 40% of Canadian equities and 80% of Canadian fixed-income issuances.[183]

[175] M4, p. 90-91
[176] M2, p.66-67; M3, p.67-68
[177] See M4-SEC-82, p.5
[178] M4, Appendix C; M4-SEC-82, p.5
[179] M1, p.120
[180] M1, p.120
[181] M1, p.120
[182] Tr.2, p.41
[183] Tr.6, p.192

4.2.15 Notably, none of the other experts exclude Canadian market data from their MRP calculations.

4.2.16 If LEI had included Canadian market data alongside U.S. data in its MRP calculation, their resulting ROE would vary by weighting: 6.13% (75/25 Canada-U.S.), 7.10% (50/50 Canada-U.S.), and 8.07% (25/75 Canada-U.S.).[184]

4.2.17 LEI's use of U.S. market data for MRP is also problematic due to an overemphasis on recent U.S. equity returns. LEI's final CAPM result is the average of three separate CAPM calculations, each with different MRP figures based on various periods of S&P total returns over 30-year Treasury bond yields.[185] The periods used are 1994–2003, 2004–2023, and 2014–2023. Since LEI's CAPM recommendation averages the MRP from each of these periods, with the 2014–2023 period included in every calculation, the result is skewed toward recent years. This weighting is significant, as the most recent period has the highest MRP (10.16%, compared to 7.28% from 1994–2003 and 7.52% from 2004–2023).[186] Furthermore, as Dr. Cleary notes, recent U.S. stock returns have been "producing abnormally high real returns relative to its longer-term history and relative to global equity returns in other markets."[187]

4.2.18 Concentric's approach differs, as it uses a historical average MRP for both Canada and the U.S. of 6.43%[188] The issue is that Concentric's historical Canadian MRP estimate is significantly higher than both the arithmetic average (by 35%) and the geometric average (by 72%) for the period 1900–2015.[189] Similarly, Concentric's historical U.S. MRP estimate is higher than the arithmetic average (by 24%) and the geometric average (by 63%) over the same period. This difference results in an MRP that is unreasonably high.

4.2.19 Dr. Cleary determined that the discrepancies appear to be driven by Concentric's use of income-only returns for bonds instead of total returns, an approach that, in his view, does not align with standard practices among finance professionals. If Concentric had used the arithmetic average estimate based on total returns, the MRP would have been

---

[184] M1-SEC-18
[185] M1, p.121
[186] M1, p.121
[187] M4, p.83
[188] M4-0-SEC-82, p.4-5
[189] M4-0-SEC-82, p.4-5

5%[190]. If it had used the geometric average, the MRP would have been 3.85%. Both are significantly lower than Concentric's chosen MRP.

4.2.20 Nexus' approach to estimating MRP is the most flawed. Unlike the other experts, who use a long-term historical MRP, Nexus employs a forward-looking estimate derived from its problematic single-stage DCF model (discussed below), resulting in an MRP of 8.83% based on expected market returns of 12.89% (from which the risk-free rate is subtracted).[191] Nexus' forecasted market returns are an unrealistic outlier, representing double the forecasts of recent surveys of market professionals[192] and more than triple nominal GDP forecasts.[193]

4.2.21 Dr. Cleary uses an MRP of 5%, representing the midpoint of the 4–6% (or 3–7%) range typically used by market professionals, as evidenced by several sources included in his analysis.[194] SEC submits that this is the most accurate estimate, reflecting the actual expectations that real investors have for market returns over the risk-free rate.

4.3 ***DCF***

4.3.1 SEC has concerns with the DCF modeling approaches used by Concentric and Nexus, particularly regarding their company growth estimates, a key input into the DCF model. Both utility experts have used unreasonably high growth rates.

4.3.2 Concentric's growth estimates are based on analysts' estimates for companies in its proxy groups.[195] In its multi-stage DCF model, which forms part of its overall ROE recommendation, Concentric assumes analyst growth forecasts for years 1–5 (5.98%), which then decline in years 6–10 (average 4.99%), eventually leading to a long-term growth rate equal to its estimate of long-term nominal GDP (3.99%).[196]

4.3.3 Nexus uses a single-stage DCF model that uses analyst growth forecasts not only for the initial years, but extending indefinitely. Based on analyst estimates for companies in its proxy group, Nexus forecasts perpetual growth of 6.31%[197] (or potentially as high as

[190] Average of 4.2% (Canada) and 5.8% (U.S.); See M4, p.84
[191] M3, p.62-63
[192] See M4, p.82, Table 7
[193] See M2, p.62, Figure 12
[194] M4, p.86
[195] M2, p.58
[196] M2, p.61, Table 11 (These referenced growth rates are for the North American Proxy Group)
[197] See Dr. Cleary attempted calculation in M4-0-SEC-83.

7.11%[198]).

4.3.4 Both Dr. Cleary and LEI were critical of using analyst growth forecasts.[199] LEI rejected the DCF methodology entirely, in part because it "primarily relies on subjective future earnings growth estimates." [200] They correctly observe that "[e]arnings forecasts can be inaccurate, tend to overvalue the cost of equity, and are consistently overly optimistic."[201]

4.3.5 SEC submits that relying on analysts' growth estimates for any length of time is inappropriate due to a well-documented bias. Analysts generally represent sellers of securities, not buyers, who are likely to have a more accurate (or, at least, more conservative) expectation of investment growth. [202] For example, past Bloomberg data indicates that less than 5% of individual ratings on all stocks in the S&P/TSX Composite Index had a "sell" recommendation, while approximately 60% had a "buy" recommendation.[203] Additionally, studies have shown that analysts' "optimism bias" inflates final DCF cost of equity estimates by an average of 2.84%.[204] Analysts' growth estimates are neither accurate indicators of actual future growth rates, nor true reflections of the market's growth expectations.

4.3.6 It should be noted, in this regard, that the perspective of ROE is from that of the investor of capital. ROE is intended to reflect the returns the investor expects. Using sell side forecasts is inherently inconsistent with that perspective.

4.3.7 Nexus' use of a single-stage DCF is particularly inappropriate, especially given its unrealistic growth rates. The AUC has stated that it will not accept "long-term or terminal growth rates that exceed estimates of the nominal long-term GDP growth rate

---

198 See attachment to EDA Interrogatories, EDA_Nexus_ME-NAICS 211 v.04, 'Ke Analysis' Tab, cell v140. We note it is very hard to understand Nexus' specific inputs and calculations, since it did not provide its underlying model as part of its prefilled evidence so parties could ask questions. It also ran its models in R code, and the Excel data worksheets it did provide, are neither well labeled nor do they provide much, if any, explanations.

199 M4, Appendix D; M1, p.126

200 M1, p.126

201 M1, p.126

202 Tr. 6, p.72; See M4, Appendix D

203 M4, Appendix D, p.138, information contained in the article reference at footnote 93.

204 M4-SEC-82, p.3; M4, Appendix BG, p.17. In addition, LEI also referenced studies that have shown that a naïve random walk (in which a given year's projected earnings are equal to the previous year's earnings plus random white noise) provides as accurate a forecast of long-term future earnings as analysts' forecasts. (See M1, p.126).

for the economy" in single-stage DCF models.[205] It agrees with Dr. Cleary's assessment that utilities are "essentially monopolies in mature markets, and because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable."[206] Even Concentric ultimately opted to use a multi-stage DCF model in its ROE estimation instead of a single-stage model.[207]

4.3.8 The AUC has accepted that, in some circumstances, initial-stage growth rates above the nominal long-term GDP growth rate may be reasonable in a multi-stage DCF. [208] However, given the source of the growth forecasts, Concentric has not provided any justification for why growth rates above nominal long-term GDP are reasonable in this context.

4.3.9 The impact of these unrealistic growth rates is significant. Based on SEC's calculations, using Concentric's forecast nominal growth rate reduces the forecast multi-stage DCF ROE across all proxy groups by an average of 53 bps. [209] For Nexus, the impact would be even greater. Applying any reasonable nominal growth rate for the proxy group companies would have a substantial effect, especially given the higher rates used in Nexus' single-stage DCF model.

4.4 ***Risk Premium***

4.4.1 Each risk premium model estimates ROE by calculating a risk premium and adding it to a bond yield. This attempts to measure the additional return (risk premium) an investor requires to invest in equity over debt.

4.4.2 SEC disagrees with how Concentric and Nexus estimate the risk premium. Both calculate the risk premium as the difference between allowed utility ROEs and the country-specific 30-year bond yield. Using allowed ROEs in other jurisdictions to estimate ROE is a circular approach. The AUC correctly found that models assuming "approved ROEs represent market return" are flawed, because approved ROEs are

---

[205] Alberta Utilities Commission, 2018 Generic Cost of Capital (Decision 22570-D01-2018), August 2, 2018, para.438
[206] Alberta Utilities Commission, 2018 Generic Cost of Capital (Decision 22570-D01-2018), August 2, 2018, para.438
[207] M2, p.60
[208] Alberta Utilities Commission, 2018 Generic Cost of Capital (Decision 22570-D01-2018), August 2, 2018, para.440-441
[209] SEC used the Concentric Excel file provided in Undertaking J2.4, Tab CEA-5 Multi-Stage DCF, and removed the generation exclusion so it included all proxy group companies.

heavily influenced by awards from other regulators and do not represent market data.[210]

4.4.3 Even if using allowed ROEs were appropriate, U.S. data is problematic because it mainly comprises decisions for vertically integrated utilities. When vertically integrated utilities are removed, Concentric's risk premium results for U.S. electricity utilities drop by 55 bps, and the North American electric proxy group's overall ROE drops by 28 bps.[211] Nexus does not provide a specific calculation removing vertically integrated utilities from its risk premium model, but based on the U.S. ROE data it used it shows a 37 bps spread between vertically integrated and distribution-only utilities' approved ROEs.[212]

4.4.4 Dr. Cleary's risk premium model is different. He uses a Bond Yield Plus Risk Premium ("BYPRP") estimate, which adds a risk premium to the utility long-term bond yield.[213] The BYPRP is superior because it uses actual market data instead of regulatory allowed returns.[214] For the long-term bond yield, Dr. Cleary uses the Bloomberg long-term A-rated Canadian utility bond index, the same index the OEB uses for its cost of capital parameter adjustment.[215] For the risk premium, Dr. Cleary applies 2.5%, reflecting a discount on the average market risk premium to account for the low-risk nature of utility companies.[216]

4.5 ***Flotation Costs***

4.5.1 The current base ROE includes a 50 bps implicit premium for flotation costs[217], which are the transaction and issuance costs related to equity issuances.[218] While these are legitimate costs for utilities to recover, if and when they are actually incurred, the 50 bps amount lacks an empirical basis and does not appear to reflect the actual costs incurred by utilities. SEC supports LEI's recommendation that flotation costs should no

---

[210] Alberta Utilities Commission, 2018 Generic Cost of Capital (Decision 22570-D01-2018), August 2, 2018, para.393
[211] See Undertaking J3.2, Attachment 1, 'CEA-1-Summary – J3.2' tab (comparing Risk Premium - Long-Term Projected Bond (as-filed) versus (excluding companies owning generation)
[212] Tr.5, p.27; K5.2, p.1. This includes accepting Nexus adjustment to exclude decisions from Illinois Commerce Commission ("ICC"). If ICC decisions were included, the spread increases to 45 bps. (K5.2, p.2)
[213] M4, p.105
[214] M4, p.105
[215] M4, p.106
[216] M4, p.106
[217] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2019, p.37
[218] M2-10-OEB Staff-16 (K2.6, p.317)

longer be recovered through the ROE, but instead be recovered based on actual costs through a deferral account.

4.5.2 Based on the industry-wide PP&E values provided by OEB Staff in Undertaking J2.1, which understates the 2025 rate base as it is based on 2023 actuals, the total cost to ratepayers across all regulated utilities of a 50 bps for flotation costs is approximately $220M a year.[219]

4.5.3 No one has been able to identify the empirical basis for the OEB's 50 bps flotation cost premium. It seems that this amount has been part of the OEB's cost of capital methodology "since the Board first introduced the premium in the early 1990s" and has been carried forward ever since.[220] This proceeding appears to be the first time the issue has been examined in detail, if at all.

4.5.4 No expert provided evidence on the actual equity and transaction costs incurred by Ontario utilities to justify a specific level of flotation costs. Concentric, in attempting to justify the continuation of the 50 bps, cited a 2006 study referenced in a textbook, which found that the average flotation costs for regulated utilities were approximately 5% of gross proceeds on equity issuances.[221] It also referenced an analysis by Enbridge Inc., that found flotation costs for utilities ranged from 2% to 10%, with an average around 5%.[222] However, as Concentric itself acknowledged, flotation costs equal to 5% of gross proceeds would translate to about a 25 bps ROE premium, which is half the current 50 bps premium.[223]

4.5.5 A review of the Enbridge Inc. analysis provided in Undertaking J3.4 shows that the average and median flotation costs are skewed by several high-cost issuances from Brookfield Infrastructure Partners and TC Energy, which are not included in any experts' proxy groups. If those issuances are removed, the average drops to 4.27% and the median to 3.3%.[224]

4.5.6 Concentric's approach to justifying flotation costs in this proceeding, which simply

---

[219] See Appendix C for calculations
[220] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, p.17
[221] M2-10-OEB Staff-16 (K2.6, p.317)
[222] M2-10-OEB Staff-16 (K2.6, p.317)
[223] M2-10-OEB Staff-16 (K2.6, p.317)
[224] Undertaking J3.4, Attachment 1, p.1

relies on the previous OEB number, contrasts sharply with how it addresses the issue elsewhere. In its U.S. testimony, Concentric typically provides a detailed analysis of actual transactional and issuance costs related to recent equity transactions of companies in its proxy groups, to calculate a specific level of flotation costs for inclusion in its ROE recommendation.[225] A review of Concentric's recent U.S. evidence shows that flotation costs as a percentage of gross equity issued are at or below 2.64%[226], and as low as 2.39%.[227]

4.5.7 Based on how Concentrics translates those calculations into a flotation cost adjustment to the ROE in the U.S., it would result in an ROE premium of 12 bps using the companies in its proposed North American Proxy Group.[228]

4.5.8 At a more fundamental level, SEC believes that the prevalence of municipal and provincial utility ownership in Ontario calls into question the use of an approach for setting or justifying flotation costs based on those incurred by publicly traded companies when issuing new shares. The largest component of flotation costs for public issuances is the underwriter's discount, a cost that privately held companies, such as those owned by the province and municipalities, do not incur. These companies only face costs related to legal, financial, and other technical advice and services.

4.5.9 To put this in perspective, Concentric's analysis of share issuance costs, presented in its evidence for Florida Light and Power, shows that excluding the underwriting discount reduces the average flotation cost percentage from 2.64% to just 0.08%.[229] For smaller utilities, even in relatively simple shareholder equity transactions, the fees may represent a higher percentage of gross equity issued, but they will still be far lower than the costs incurred by publicly traded utilities that pay underwriting fees.

4.5.10 When pressed, Nexus does not even attempt to justify the 50 bps amount with anything other than a reference to historical practice.[230] Initially, Nexus referenced the capital

---

[225] Tr.3, p.30

[226] Tr.3, p.30. See Direct Testimony of James M. Coyne, on behalf of the Florida Power & Light Company (Florida Public Service Commission Docket No. 20210015-EI), March 21, 2021, p.83 (K2.6, p.267). Underlying calculations set out in Exhibit JMC-10, p.1 (K2.6, p.272)

[227] Tr.3, p.32. See Direct Testimony of James M. Cone, for Duke Energy Carolinas, LLC (Public Service Commission of South Carolina, Docket no. 2023-338-E) January 4, 2024, Exhibit 9, p.1 (K2.6, p.243).

[228] Undertaking J3.3_Attachment 1, Tab 'Flotation Costs Ex. – NA PG'. SEC used 2.64% as the Flotation Cost Percentage, which produces a Flotation Cost Adjustment of 0.12%

[229] K2.6, p.271

[230] M3-10-OEB Staff-38

market experts that the OEB convened as part of the 2009 review. At the oral hearing, when confronted and asked to identify where in the record those experts said that 50 bps were appropriate, Dr. Pampush admitted, "just our understanding, and if it's not the case, then I really don't know where the basis for the 50 points."[231] Those capital market experts did not provide support for the 50 bps, nor did they comment on the specific issue.

4.5.11 Dr. Pampush further argued that by previously setting the flotation cost at 50 bps, the "Board [was] essentially saying, yes, you are owed this cost…[w]e have decided this is the cost, but we are not going to allow you to recover it."[232] At no point has the OEB said that flotation costs should never be changed, and such an approach would be entirely inappropriate, as it would bind future panels of the OEB, which it cannot do. Notably, when the British Columbia Utilities Commission ("BCUC") removed its 50 bps flotation cost premium, there was no indication from investors that this disallowed some promised cost.

4.5.12 Nexus claims that flotation costs should also account for the dilution of share value from equity issuances.[233] No other expert recognizes this as a valid cost to be recovered from ratepayers, and Nexus is not aware of any regulator that supports this view.[234] Dilution, which is not automatic, is a cost to investors, not the company. Moreover, Nexus does not propose that customers receive a rebate for the benefits investors gain from share buybacks, which increase share value and are the inverse of dilution.[235]

4.5.13 The evidence in Ontario shows that there are very few equity investments in utilities through share issuances or other equity injections after the commencement of operations. When they do occur, they are infrequent. Of the OEA/CLD+ utilities, only Enbridge receives regular equity investments from its parent, and only Toronto Hydro has had any recent equity investments.[236] This includes Hydro One, OPG, Alectra, Elexicon, and Hydro Ottawa.[237] Hydro One has stated that it does not expect to require

[231] Tr.5, p.51
[232] Tr.5, p.52
[233] Tr.5, p.55
[234] Tr.5, p.55-56
[235] Tr.5, p.56-57
[236] M2-10-SEC-41c, p.8-9 (K2.6, p.294-295)
[237] M2-10-SEC-41c, p.8-9 (K2.6, p.294-295). UCT 2 has had a number of equity investments through 2022, but they all appear to be before the utility started operations when its East-West Tie line entered service in April of 2022.

an equity investment through the remainder of its rate term.[238]

4.5.14 Both Concentric and Nexus argue that flotation costs should also account for the need for financial flexibility, which is distinct from transaction and issuance costs.[239] SEC disagrees. Financial flexibility should not be a factor in setting the ROE. As Dr. Cleary testified, any need for financial flexibility should be addressed through the appropriate capital structure, with a "buffer in terms of additional equity."[240] The BCUC reached the same conclusion, finding that "the appropriate way to account for required financial flexibility is to adjust the utility's capital structure."[241]

4.5.15 Given the infrequent equity investments, the lack of an empirical basis for the existing 50 bps premium, and evidence that actual costs are likely much lower, LEI's proposal to remove flotation costs from the ROE calculation is appropriate.[242]

4.5.16 SEC submits that the most appropriate method for recovering flotation costs is to establish a generic deferral account, where utilities could later seek recovery of their actual costs when incurred. This approach ensures utilities can recover their prudent flotation costs, while protecting customers from overpaying. The OEB would then assess the actual costs, evaluate them for prudence, and determine the recovery period.

4.5.17 This approach is similar to the BCUC's recent decision on the same issue. The BCUC rejected a proposal to include the same 50 bps flotation premium in the ROE, finding it "too vague to be a just and reasonable expense recoverable from ratepayers."[243] It similarly determined that if Fortis BC and Fortis Energy Inc. actually incur flotation costs, they can present supporting documents, to "enable the BCUC to review it to determine that is a just and reasonable expenditure."[244]

---

[238] K2.6, p.116; Tr.3, p.22
[239] Tr,4, p.52; Tr.5, p.138; M2, p.71; M2-10-OEB-Staff-16
[240] Tr.6, p.166-167
[241] British Columbia Utilities Commission, Decision and Order G-236-23, Generic Cost of Capital Proceeding (Stage 1), September 5, 2023, p.125
[242] M1, p.96
[243] British Columbia Utilities Commission, Decision and Order G-236-23, Generic Cost of Capital Proceeding (Stage 1), September 5, 2023, p.126
[244] British Columbia Utilities Commission, Decision and Order G-236-23, Generic Cost of Capital Proceeding (Stage 1), September 5, 2023, p.126

4.6 ***SEC Base ROE Recommendation***

4.6.1 SEC recommends a base ROE of 7.58% that would be applicable to electricity distributors, transmitters, and natural gas distributors (see discussion on scope as part of section 3.5).

4.6.2 SEC agrees that ideally multiple models should be used to forecast the ROE, considering the inherent difficulty in estimating an appropriate ROE. The CAPM, DCF and risk premium model are the commonly accepted approaches used by the experts.

4.6.3 Notwithstanding its concerns with using any peer groups to represent utilities with comparable risk to Ontario utilities, SEC submits that the most appropriate is Concentrics' proxy group, excluding companies with generation assets and material unregulated operations (see Undertaking J4.2) for CAPM and DCF models.

4.6.4 From there, SEC made a number of key modifications to the calculations undertaken by Concentric, to address the concerns detailed in these submissions. To ensure there is a sufficient sample of companies, SEC has used results from only the (revised) North American Combined Proxy Group.

4.6.5 For the equity premium approach, SEC has Dr. Cleary's proposed BYPRP as it is the only one that uses actual market data.

4.6.6 SEC proposes a base ROE of **7.58%,** based on the average of the following three results (the underlying calculations are included in Appendix C):

- ***CAPM (multi-stage) - 7.03%,*** SEC adjustments:
    - ***Risk Free Rate.*** Average last 5 days of September actual Government of Canada 30-Year bond yields**.**
    - ***Betas***. Raw as opposed to adjusted betas.[245]
    - ***MRP.*** 5% as proposed by Dr. Cleary.
    - ***Flotation Costs:*** Removed as SEC proposes actual costs be recovered through a DVA.

- ***DCF (Historical MRP) – 8.65%,*** SEC adjustments:
    - ***Growth rates.*** All years set at forecast nominal GDP growth.

[245] SEC used the formula to convert adjusted betas to raw betas as set out in M2-10-OEB Staff-12(b)

- ***Flotation Costs.*** Removed as SEC proposes actual costs be recovered through a DVA.

- ***Equity Premium (BYPRP) – 7.10%***

4.7 ***Annual ROE Formula***

4.7.1 The OEB currently adjusts the approved ROE each year through a formula that accounts for market changes over time. This formula adjusts the base ROE by 50% of the annual changes in the long-term Canada bond yield (Long Canada Bond Forecast "LCBF") and a utility bond spread[246], compared to values used when the base ROE was initially set.[247]

4.7.2 The rationale behind the OEB's 50% adjustment factor for bond yields and utility spreads is that, while there is a statistical relationship between these changes and the cost of equity, the sensitivity of macroeconomic shifts does not directly correlate to utility equity costs.[248] This 50% adjustment factor was developed based on regulatory analysis used by participants in the 2009 consultation.[249]

4.7.3 LEI recommends, that the adjustment factors be changed to 0.26% for the LCBF and 0.13% for utility bond spreads[250], based on a multivariate regression analysis.[251] SEC submits that the OEB should reject LEI's recommendation, as it is based on flawed regression analysis. First, it uses U.S. regulatory ROE decisions as the dependent variable, which, as SEC has argued, should not represent the cost of equity for Ontario utilities. Second, the relevance of analyzing *U.S.* ROE decisions in relation to Government of *Canada* bond yields is unclear, as there is no known direct relationship between the two.[252] Third, LEI's analysis considers BBB-rated corporate bonds rather than A-rated utility bond yields, which are actually included in the formula. Lastly, the LEI regression focuses only on bond yields, rather than spreads over government bond

---

[246] OEB calculates the utility spread as the difference between A-rated utility 30-year yields compared to Government of Canada 30 year-yields.
[247] M1, p.102; [Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009](), p.49
[248] [Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009](), p.47
[249] M1, p.102; [Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009](), p.46
[250] M1, p.127
[251] M1, p.116
[252] M4, p.46

yields, which is what half of the current formula considers.

4.7.4 Concentric, based on its own multivariate regression analysis, recommends changing the adjustment factors to 0.40% for the LCBF and 0.33% for utility bond spreads.[253] Concentric's regression analysis is also problematic for similar reasons to LEI's. It compares U.S. ROE decisions in part to U.S. government bond yields, and its regression fit measures are weak, with an R-squared of 0.54, meaning nearly half of the variation in its observations is unexplained.[254]

4.7.5 Dr. Cleary proposes increasing the adjustment factor for both the LCBF and utility bond yields from 0.5% to 0.75%.[255] He bases this recommendation on the evidence, that allowed ROEs have not declined sufficiently in line with the reductions in the cost of capital, as indicated by declines in the risk-free rate and A-rated utility bond yields over the last two decades.[256]

4.7.6 Besides updating the base values, SEC recommends that the OEB maintain the current formula and adjustment factors, although for different reasons than those cited by the experts. Dr. Cleary is correct in noting that the current formula has not resulted in sufficient ROE declines, but it is also essential for the formula to balance the impact of macroeconomic and market changes with the need for year-over-year stability. The 50% adjustment factor achieves this balance, and should override proposals based on flawed regressions.

4.7.7 The OEB should discontinue the use of a forecast of the LCBF and, instead, adopt the prevailing actual 30-year Government of Canada bond yields (such as the average of the last five days in September) as these are a more accurate indicator of future yields. This approach aligns with the SEC's position on setting the DLTDR (see paragraph 5.2.2).

---

[253] M2, p.106
[254] Tr.4, p.102; M2, p.106
[255] M4, p.46-47
[256] M4, p.47

5 SHORT AND LONG-TERM DEBT

5.1 ***Short Term Debt***

5.1.1 The OEB currently calculates the DSTDR as the 3-month Bankers' Acceptance rate plus a spread determined by a survey of Canadian banks (reflecting the spread of short-term debt issuances over Bankers' Acceptance rates).[257] However, a change in methodology is necessary due to the discontinuation of the 3-month Bankers' Acceptance rate this past June.[258]

5.1.2 Both LEI and Concentric recommend a methodology that replaces the 3-month Bankers' Acceptance rate with the 3-month Canadian Overnight Repo Rate Average (CORRA) futures rate over the next 12 months.[259] Dr. Cleary is also agreeable to either LEI's proposal or the use of the prevailing CORRA rate as of September 30th. [260]

5.1.3 SEC finds LEI's proposal acceptable. Since there is no evidence on record, as there is with the DLTDR, regarding the difference in accuracy between using a forecast rate versus the September 30th actual rate, SEC has no issue with using the forecasted CORRA futures rate.

5.2 ***Long-Term Debt***

5.2.1 SEC believes there are a number of areas regarding long-term debt that could benefit from improvement and clarification.

5.2.2 ***Deemed Long-Term Debt Rate Methodology.*** LEI proposes modest adjustments to the current methodology. It recommends using a publicly available forecast of the 30-year Government of Canada bond yields to determine the LCBF, rather than the current method, which relies on a non-public Consensus Forecast of 10-year Government of Canada bonds plus the 30-year over 10-year Government of Canada bond spread.[261]

5.2.3 Dr. Cleary proposes using the prevailing 30-year Government of Canada bond yield instead of a forecast. His evidence demonstrates that over the 2021–2023 period, using

[257] M1, p.76
[258] M1, p.76
[259] M1, p.82; M2, p.33
[260] M4, p.23
[261] M1, p.90; The proposal was also supported by Concentric (M2, p.38).

the existing 30-year yields, produces a statistically significant and more accurate forecast for the subsequent period than the current forecasting method.[262] During this period, the average 30-year Government of Canada bond yield was 2.58%, while the annual Consensus September forecast resulted in an average yield of 2.94%, leading to a DLTDR that was 0.38% higher than it should have been.[263] A methodology using the actual yield on September 30th would have resulted in an average of 2.57% over the period, a difference of only 0.01%.[264]

5.2.4 SEC supports Dr. Cleary's revised approach, as it produces a significantly more accurate DLTDR.

5.2.5 If the OEB disagrees with Dr. Cleary's proposal, we recommend adopting LEI's proposal to use a publicly available forecast. This approach ensures that the public has access to the same underlying input data without needing to pay a substantial amount for a Consensus subscription. LEI notes, that all major banks provide public forecasts of 30-year Government of Canada bond yields, which the OEB can use. If the OEB adopted this approach, it still must establish a transparent process for determining the forecasted 30-year Government bond yield, including the sources to average and the time period to consider.

5.2.6 We have a slight disagreement with one aspect of Dr. Cleary's recommendation, the proposal to use the prevailing 30-year Government of Canada bond yield from a single day, September 30th.[265] SEC understands his rationale, which is that averaging yields over a month may not reflect the best available data, as it moderates the impact of macroeconomic changes occurring within that month (such as Bank of Canada rate changes or inflation forecasts). Since the DLTDR is intended as a forecast for the coming year, it should reflect the post-macroeconomic impact on yields, not earlier values.

5.2.7 However, bond yields fluctuate daily, often due to factors unrelated to major macroeconomic news.[266] SEC suggests that the OEB consider averaging yields over a slightly larger range, such as 5 days, to smooth out daily fluctuations that may be due to

[262] M4, p.25
[263] M4, p.25
[264] M4, p.25
[265] Presumably, Dr. Clearly means the last business day of September.
[266] For example, the last 5 days of September 2024, the Government of Canada bond yields were 3.14%, 3.15%, 3.20%, 3.20% and 3.13%. (See OEB Letter, 2025 Cost of Capital Parameters (October 31, 2024), Appendix A)

'noise.'

5.2.8 ***Long-Term Debt Transaction Costs.*** SEC supports the continued practice of including long-term transaction costs as part of the interest expense, amortizing them over the term of the specific debt instrument using the effective interest rate method.[267] This approach allows for a reasonable allocation of *actual* transaction costs over the period that matches the debt's benefit (i.e. its term).

5.2.9 LEI proposes that debt transaction costs be included as operating costs due to the "irregularity in frequency and amount of debt issuance."[268] SEC submits that this irregularity is actually a reason to include these costs as an interest expense, amortized over the term of the debt issuance. The infrequency and magnitude of debt issuance make including these costs in an OM&A budget problematic, as they are inherently lumpy and challenging to forecast. These issues do not arise under the existing practice. The current practice also correctly matches the cost of the transaction to the time periods in which that cost will benefit the company, fundamental to proper accounting of the cost. It is acceptable, however, for a utility to include certain debt transaction costs in the OM&A budget when the costs are predictable and ongoing, such as those related to reporting requirements.

5.2.10 The treatment of costs for debt differs from that for equity. For equity, the issue with flotation costs is that they are set on a generic basis, while the weighted average long-term debt rate is utility specific.

5.2.11 ***Notional Debt.*** Clarification is needed regarding the ratemaking treatment of notional debt, i.e. the portion of deemed debt exceeding a utility's actual debt. Specifically, the question is whether notional debt attracts a utility's actual weighted average cost of debt, the DLTDR, or some other rate.

5.2.12 The 2009 Report does not explicitly address notional debt, and subsequent OEB decisions on the issue have been conflicting. In the decision on OPG's 2011-2012 payment amounts, the OEB ruled that the weighted average cost of existing and forecasted long-term debt applies to the unfunded portion of long-term debt.[269] This approach was reaffirmed in the OEB Staff's 2016 Report, which noted that the 2015

[267] M1, p.93
[268] M1, p.96
[269] *Decision with Reasons* (EB-2010-0008), March 10, 2011, p.125

electricity distribution filing requirements (for 2016 rate applications) [270] clarified that notional debt attracts a utility's actual weighted average cost of debt. [271]

5.2.13 The matter became more confusing after the OEB's decision in Oshawa PUC's 2015-2019 Custom IR application, where the OEB found the opposite, that the deemed rate should be applied to unfunded debt (i.e. notional debt).[272] Additionally, the clarification regarding notional debt in the 2015 electricity distribution filing requirements was subsequently removed.

5.2.14 SEC submits that as long as the OEB uses a deemed capital structure, the appropriate approach is to apply a utility's actual weighted average cost of debt to any notional debt. At the same time, if a utility is underleveraged during periods of low debt rates and later moves closer to the deemed capital structure during periods of high debt costs, the transparency of its overall financing strategy could impact the prudence of its actual weighted average cost of capital.[273]

5.2.15 ***Affiliate Debt.*** SEC does not take issue with the affiliate debt rules set out in the 2009 Report, but requests that additional guidance be provided when utilities are considering affiliate debt.[274] The OEB should make it clear that utilities should always ensure that both the terms and interest rates of its debt, regardless of it source, are reasonable.

5.2.16 Too often, SEC has seen utilities with affiliate debt that is up for renewal, can be repaid on short notice, or is callable on demand, relying on the DLTDR as justification for the debt's reasonableness. This is not sufficient. It is common for the DLTDR to be higher than the rates offered by banks and other third parties. Utilities must seek out the most cost-effective option, and should not rely on the DLTDR as a justification of reasonableness.

5.2.17 ***Role of Deemed Long-Term Debt Rate.*** The 2009 Report states that "[t]he deemed

---

[270] Filing Requirements For Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications, Chapter 2, Cost of Service, p.47

[271] OEB Staff Report, Review of the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), January 14, 2016, p.7

[272] *Decision and Order* (EB-2014-0101), November 12, 2015, p.32

[273] The electricity distribution filing requirements require an applicant to provide an overview of its financing strategy. (See Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service, p.37)

[274] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.53-54

long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances."[275]

5.2.18 The issue arises because the DLTDR is based on forecasts of 30-year bond rates, while the debt to which it is applied is often for terms shorter than 30 years. As LEI correctly notes, "[b]onds with longer maturities generally have higher interest rate risk than similar bonds with shorter maturities."[276] Therefore, using the DLTDR as a *proxy* for instruments with less than 30-year maturity is inappropriate. It represents a consistent upward bias in utility debt costs.

5.2.19 The OEB should clarify its policy on this matter. It should specify that for debt with less than 30 years to maturity, the DLTDR may act as a cap or ceiling, but not as a proxy. This distinction is important, because it signals the expectation that the interest rate for shorter-term debt should be lower to reflect the reduced maturity.

5.2.20 Another benefit of this clarification is that, in SEC's experience, electricity distributors often use the DLTDR of a given year as a placeholder for forecasted debt issuances. This may be appropriate if the forecasted debt issuance is for a 30-year term, but it is not suitable for debt instruments with terms of 5, 10, or 15 years.

5.2.21 ***Recovery of Transaction Costs.*** The current practice of most utilities is to incorporate a debt issuance interest rate premium to recover transaction costs over the life of the instrument. In SEC's experience, utilities often either, (a) add an additional 50 bps to the debt interest rate to represent transaction costs, or (b) forecast the actual transaction costs related to each specific debt issuance and then calculate an effective interest rate premium to recover those costs over the length of the debt.

5.2.22 LEI recommends that debt transaction costs be treated as an operating expense, and not be included as part of the debt interest costs, consistent with its proposal for equity transaction costs (flotation costs).[277]

5.2.23 SEC does not support LEI's proposal regarding the recovery of transaction costs for debt. Debt transaction costs can easily be translated into an effective interest rate, and

---

[275] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.53
[276] M1-6-SEC-16a (k2.6, p.53)
[277] M1, p.90

since debt costs are specific to each utility, it makes more sense to maintain the current practice and match the transaction costs to the periods in which they are generating a benefit. Additionally, unlike with flotation costs, there is no evidence that utilities are recovering debt transaction costs that they do not incur.

6 OTHER COST OF ISSUES

6.1 *Prescribed Interest Rate on DVA Balances*

6.1.1 Currently, utilities must calculate interest on DVA balances quarterly based on a prescribed interest rate set by the OEB, equal to the 3-month bankers' acceptance rate plus a fixed spread of 25 bps.[278]

6.1.2 LEI recommends maintaining the current approach for DVA balances, but notes that a new reference rate will be required due to the discontinuation of the 3-month bankers' acceptance rate this past June. [279] Similar to the DSTDR, SEC believes that using the 3-month CORRA as the reference rate is most appropriate.

6.1.3 Concentric agrees with LEI's approach, but only for DVAs cleared within one year. It proposes setting the prescribed interest rate for all other DVAs to the utility-specific weighted average cost of capital ("WACC").[280]

6.1.4 The OEB should reject Concentric's recommendation and maintain the current approach, for several reasons.

6.1.5 First, Concentric's proposal would subject nearly all account balances to the significantly higher WACC interest rate. This is because the OEB rarely clears account balances within a year, as they must first be audited. For example, an amount recorded in a DVA in 2024, would be cleared at the earliest in the 2025 rates application and implemented at the start of the 2026 rate year.

6.1.6 Second, the largest DVA balances typically involve pass-through accounts in Group 1, such as commodity-related accounts, which carry minimal risk for utilities since these costs are ultimately passed through to customers. It would be inequitable for these accounts to attract an interest rate based on WACC, which includes an equity return component, as these accounts carry virtually no risk regardless of balance duration.

6.1.7 Similarly, Group 2 accounts have minimal risk of disallowance because the OEB initially approves these accounts, either as pass-throughs, or based on a prior prudence

[278] M1, p.165
[279] M1, p.165
[280] M1, p.166

assessment. Thus, Group 2 accounts also should not attract interest rates designed to reflect utility risk profiles.[281]

6.1.8 Third, Concentric's proposal assumes utilities fund DVA balances through equity and long-term debt, yet there is no evidence of this, particularly if they are equity funded.

6.1.9 Fourth, setting a prescribed interest rate close to WACC for DVAs could deter both intervenors and the OEB from approving new deferral and variance accounts, due to high annual interest costs. This would limit utility risk management and flexibility, and would disproportionately affect customers if utilities defer rebasing applications[282], including the potential 10-year deferrals allowed under the MAADs Handbook.[283] This impact was not considered in the OEB's recent MAADs policy review.[284]

6.1.10 If the OEB does approve a significantly higher interest rate methodology for DVA balances, it must also amend its policy to require utilities to seek clearance for all Group 2 DVAs annually, rather than waiting until the next rebasing application. SEC acknowledges that this would present substantial regulatory challenges, as it would shift routine rate adjustments from delegated authority to full hearings. However, it would be manifestly unfair for customers to allow utilities to earn substantial interest, including equity returns, on these balances over an extended period.

6.2 ***Prescribed Interest Rate on CWIP***

6.2.1 ***CWIP Rate.*** The OEB's current practice is to calculate the prescribed interest rate on CWIP balances quarterly, based on the FTSE Canada Mid-Term Bond Index (All Corporate Yield).[285] This methodology was adopted by the OEB to reduce the administrative burden associated with managing multiple CWIP rates based on varying construction periods (short- and long-term).[286]

---

[281] Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service, p.65

[282] The OEB's approach to deferral requests "looks at both financial and non-financial performance. This includes consideration of information about return on equity and recent capital expenditures, as well as the distributor's scorecard performance." (See OEB Letter, Re: Application for 2023 Electricity Distribution Rates, (December 1, 2021), p.2)

[283] Handbook to Electricity Distributor and Transmitter Consolidations (Revised July 11, 2024), p.17-18

[284] See Evaluation of Policy on Utility Consolidations (EB-2023-0188)

[285] M1, p.166

[286] M1, p.167; OEB Letter, Re: Approval of Accounting Interest Rates Methodology for Regulatory Accounts (EB-2006-0117), November 28, 2006, p.9

6.2.2 Concentric recommends using a utility-specific WACC for CWIP.[287] SEC believes there is no need to change the current methodology for setting the prescribed CWIP rate, so it should remain in place.

6.2.3 SEC disagrees with Concentric that there should be any equity return on CWIP balances, as it proposes through the use of the WACC.

6.2.4 Utilities are compensated for construction of assets through the ROE when the asset is added to rate base. It should not "double recover" through receiving a return on the funds used during construction, and then a return on that accrued interest. Moreover, Concentric's approach assumes that CWIP is funded by utility equity. Often this is explicitly not the case. For many utilities that implement projects that take more than a year to complete, they fund at least the construction costs through construction loans.[288]

6.2.5 It is notable that in Enbridge's most recent rebasing application, the company harmonized its accounting policies and proposed using the OEB's prescribed interest rate for CWIP for Interest During Construction. This differs from Enbridge Gas Distribution's historic approach, which applied the weighted average cost of debt. [289]

6.3 ***Implementation***

6.3.1 ***ROE, DLTDR, DSTDR.*** SEC submits that changes in the cost of capital components (ROE, DLTDR and DSTDR) should be implemented at a utility's next rebasing application, unless it is rebasing for 2025 rates, and the adjustment is permitted under any approved settlement proposal.[290] For all other utilities, applying these changes at other times could disrupt the overall rate structure and fairness of the regulatory process.

---

[287] M2, p.165

[288] Since the OEB has a specific methodology, utilities are not required to report on how they actually fund expenditures that attract CWIP. A review of the record in a number of proceedings, though, does provide some insight in utility use of construction loans. See for example Festival Hydro (EB-2024-0023, Interrogatory Responses Attachment 8_1-SEC-2, '2025 Budget', pdf p.560; Synergy North (EB-2023-0053, Interrogatory Responses, Attachment 5-3, SNC Budget Correspondence, pdf p.105); EB-2020-0026, Halton Hills Hydro (EB-2020-0026, SEC-CQR-13, p.2)

[289] M2-19-SEC-58

[290] For example, the filed Toronto Hydro Settlement Proposal for 2025-2029 rates states: "….the Parties acknowledge that for the 2026-2029 capital structure and cost of capital parameters Toronto Hydro will implement whatever outcomes are decided by the OEB in the Generic Cost of Capital Proceeding (EB-2024-0063), including what the OEB decides with respect to implementation." (See EB-2013-0195, Settlement Proposal, August 16 2024, p.47). In contrast, the filed Settlement Proposal for B2M LP states. "Notwithstanding the Generic Cost of Capital Proceeding, the Parties agreed that: (i) the 2025 to 2029 cost of common equity and short-term debt rate will be based on the OEB's 2025 cost of capital parameters to be published in the fourth quarter of 2024…." (EB-2024-

6.3.2 For most of Ontario's utilities, rates are set under the Price Cap IR rate-setting framework. After the initial cost of service year, rates are adjusted by a formula designed to decouple costs from rates. For these utilities, it is unclear how changes in cost of capital parameters could be incorporated into rates mid-term.

6.3.3 When the OEB sets rates through cost of service or Custom IR applications, it considers the reasonableness of the entire revenue requirement and bill impacts, including the cost of capital. Changing one component of the rates after the fact would be unfair. Had the OEB known the cost of capital would be higher or lower, it likely would have influenced the level of capital spending allowed, to ensure that the overall rates and bill impacts were reasonable.

6.3.4 If the OEB considers adjusting utility base rates before rebasing, it will need to determine the appropriate method for doing so through a further phase of this proceeding. Otherwise, the OEB could face 60+ applications from utilities, each proposing their own approach, which would lead to a complex and time-consuming regulatory process. This would likely prompt ratepayer groups involved in the initial cost of service or Custom IR application to intervene, seeking to review the approach and calculations.

6.3.5 For Custom IR applications, SEC agrees with Concentric that, depending on the specific decision and terms of the settlement proposal, a mid-term rate adjustment may not be allowed.[291]

6.3.6 Regardless, SEC submits that a mid-term adjustment for a change in cost of capital parameters is not generally permitted. Under all three rate-setting mechanisms (Custom IR, Price Cap, and Annual IR), the ability to adjust rates outside of a cost of service or Custom IR application is strictly limited, unless specified at the time.[292] With the limited exception of a utility's 2025 test year where the current proceeding was

---

0116, Settlement Proposal, p.19)

[291] M2-19-SEC-56a. Hydro One and Hydro Ottawa both take the view that their specific Custom IR settlement proposals do not permit an adjustment to the cost of capital as a result of this generic hearing until they rebase. (See M2-19-SEC-56b)

[292] For example, specified by an approved settlement proposal, decision, or established rate adjustment mechanism such as IRM, ICM, Z-Factor, or +/-300 bps off-ramp. See Handbook on Utility Rate Applications, p.i, 27-38; Filing Requirements for Electricity Distribution Rate Applications, Chapter 3, Incentive Rate-Setting Applications, June 15, 2023, p.22, 24 and 26

expressly contemplated, SEC is not aware of any adjustment mechanism available.

6.3.7 ***DVA Prescribed Interest Rate Change Implementation.*** SEC acknowledges that certain changes to other parameters could be implemented before a utility rebases. For example, if the OEB changes how it determines interest on DVA balances, these changes could be implemented without the same complications as adjustments to base rates. However, for certain utility specific DVAs, it cannot be implemented until their rebasing application as a result of the specific language in certain approved Accounting Orders, often as a result of an agreed Settlement Proposal. For example, most existing Enbridge DVA Accounting Orders specify that the "[s]imple interest is to be calculated on the opening monthly balance of this account using the OEB-approved EB-2006-0117 interest rate methodology."[293] Utilities will need to review their specific approved Accounting Orders.

6.3.8 If the OEB does makes a material change to how it calculates interest, then the OEB should require utilities to clear all Group 2 accounts on an annual basis.

6.4 *Review, Reporting and Monitoring.*

6.4.1 ***Periodic Review Period.*** SEC believes that a full review every five years through a generic hearing, as is being undertaken in this proceeding, is appropriate, and balances the need to keep cost of capital parameters reasonable with the goal of regulatory efficiency.

6.4.2 If circumstances change significantly due to macroeconomic conditions, utility business or financial risk, or any other indicators from ongoing OEB monitoring that suggest the current parameters are no longer consistent with the FRS (whether too high or too low), the review can be scheduled sooner. Additionally, it should always be possible, in the context of a specific rate application, for both the applicant utility and intervenors, to propose a deviation from the cost of capital parameters and policy when appropriate.

6.4.3 ***Utility Reporting and OEB Monitoring.*** LEI proposes several enhancements to utility reporting that would help the OEB assess whether the cost of capital parameters remain appropriate over time.[294] The additional reporting would include, among other items, details on short-term and long-term debt borrowing and equity issues throughout the

---

[293] See for example, *Interim Rate Order* (EB-2022-0200), April 11, 2024, Appendix C
[294] M1, p.151

year. Concentric opposes this enhanced reporting, arguing that it is unnecessary and "administratively burdensome."[295]

6.4.4 SEC agrees with LEI, that the additional information is valuable for monitoring the reasonableness of cost of capital parameters. The reporting requirements are not administratively burdensome, especially when considering the overall cost to customers of a utility's cost of capital. For debt, the reporting should simply include the utility's actual annual cost of short-term borrowing and the same information currently provided in Appendix 2-OB for long-term debt rates. Utilities have to maintain this information anyway to report at each rebasing.

6.4.5 For equity, the information should include the amount of equity issued in a given year, its source, number of shares issued, share price, number of outstanding shares, gross proceeds, and net proceeds after transaction costs.

6.4.6 The debt information is essential for the OEB to compare deemed rates with actual borrowing rates, while the equity data allows for monitoring of the need for equity capital and the costs associated with raising it.

6.5 ***Cloud Computing***

6.5.1 The approved issues list asks, 'Should carrying charges and/or another type of rate apply to the Cloud Computing deferral account? If so, what rate should be applied?' SEC submits that the OEB should apply the prescribed interest rate applicable to DVAs, using whatever methodology is approved in this proceeding. There is no compelling reason for cloud computing costs to be treated differently from other costs included in a deferral or variance account.

6.5.2 It is important to clarify the scope of this issue on the Issues List and what the OEB deemed in scope for this proceeding. In its letter establishing a generic deferral account to record incremental cloud computing implementation costs, the OEB stated that the specific carrying cost (or other rate) to be applied to the account would be considered as part of the generic proceeding on cost of capital.[296] This is reflected in the approved issue. However, the OEB also hinted at a possible rationale for considering a different rate, stating that the "risk profile of cloud computing solutions and on-premises

[295] M2, p.145
[296] OEB Letter, Re: Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs, (November 2, 2023), p.3

solutions is expected to be included in the scope of that cost of capital proceeding."[297]

6.5.3 SEC finds LEI's recommendation confusing, but understands it to mean that any balance in the cloud computing deferral account would attract the prescribed interest rate, but at rebasing, the OEB would essentially add those costs to rate base, after which the unamortized costs would attract WACC.[298] If this interpretation is correct, only the first part of the recommendation directly addresses the approved issue.

6.5.4 LEI's recommendation regarding rate treatment of the balance at rebasing addresses a different question from what is outlined in the approved issues list. In its letter establishing the cloud computing deferral account, the OEB stated that utilities could propose regulatory treatment for any material cloud computing implementation costs, with the expectation that the proposal "is expected to be informed by any results of the generic proceeding related to the issue."[299] LEI's recommendation to treat the unamortized balance at rebasing as a deemed capital addition attracting WACC goes beyond providing information to inform a utility's proposal, it suggests a specific regulatory treatment. SEC submits that this was not what the OEB intended when it issued the letter, nor is it covered by the approved issues list. Parties might have engaged experts to address that specific question if they had known that was within the scope.

6.5.5 Changing the regulatory treatment of an issue is both complex and fact specific. The OEB retained KPMG to review this matter, who examined eight different approaches, each with its own advantages and disadvantages.[300] KPMG concluded that "the different rate-making approaches analyzed have quite different impacts on the allocation of costs to customers over time, on utility funding requirements, and on the profile of cost recovery."[301] It further noted that "the best option in any given circumstance may depend on the specific factors at play" and that "[r]elevant considerations may include the size of the project relative to overall capital budgets, the degree of incentive

---

[297] OEB Letter, Re: Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs, (November 2, 2023), p.3

[298] M1-22-SEC-25; M1-22-CCC-9; M1, p.173-175

[299] OEB Letter, Re: Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs, (November 2, 2023), p.4

[300] KPMG, Cloud Computing Costs: Regulatory Options For The Treatment of Cloud Computing Costs (September 8 2023)

[301] KPMG, Cloud Computing Costs: Regulatory Options For The Treatment of Cloud Computing Costs (September 8 2023), p.3

required, and the accuracy of available cost estimates available."[302] SEC agrees, and this is why the OEB should not determine the future regulatory treatment of cloud computing costs within the context of this proceeding.

6.5.6 The OEB created the cloud computing deferral account to address the disincentives utilities faced in implementing cloud computing solutions during the incentive rate-setting period, when such costs were not built into rates.[303]

6.5.7 SEC agrees with LEI that the OEB-prescribed interest rate should be used for carrying charges on the deferral account. There is no evidence suggesting that cloud computing costs have a different risk profile than other costs, which would warrant different regulatory treatment. The OEB's establishment of the account removes the disincentive utilities may face during an IRM term in choosing cloud computing solutions over traditional capital IT investments.

6.5.8 What happens to those costs when the DVA is cleared should be considered by the OEB in the rebasing proceedings of the utilities that have incurred those costs. One size will almost certainly not fit all.

All of which is respectfully submitted.

Mark Rubenstein
Counsel for the School Energy Coalition

[302] KPMG, Cloud Computing Costs: Regulatory Options For The Treatment of Cloud Computing Costs (September 8, 2023), p.3
[303] OEB Letter, Re: Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs, (November 2, 2023), p.2

APPENDIX A – CONCORDENCE WITH ISSUES LIST

OEB Issue	SEC Argument Reference
A. Geneal Issues	
1. Should the approach to setting cost of capital parameters and capital structure differ depending on: a) the source of the capital (i.e., whether a utility finances its business through the capital markets or through government lending such as Infrastructure Ontario, municipal debt, etc.)? b) The different types of ownership (e.g., municipal, private, public, co-operative, not for profit, Indigenous / utility partnership, etc.)?	1.2
2. What risk factors (including, but not limited to, the energy transition) should be considered, and how should these risk factors under the current and forecasted macroeconomic conditions be considered in determining the cost of capital parameters and capital structure?	3.1-3.4
3. What regulatory and rate setting mechanisms impact utility risk, and how should these impacts be considered in determining the cost of capital parameters and capital structure?	3.1-3.4
B. Short-Term Debt	
4. Should the short-term debt rate for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be set using the same approach as set out in the OEB Report?	5.1
5. If no to Issue #4, how should the short-term debt rate be set?	5.1
C. Long-Term Debt	
6. Should the long-term debt rate for electricity distributors, natural gas utilities, and OPG continue to be set using the same approach as set out in the OEB Report and as set out in the Staff Report for electricity transmitters?	5.2
7. If no to Issue #6, how should the long-term debt rate be set?	5.2
8. How should transaction costs incurred by utilities be considered when setting the long-term debt rate?	5.2
9. What are the implications of variances from the deemed capital structure (i.e., notional debt and equity) and how should they be considered in setting the cost of long-term debt?	5.2.11
D. Return on Equity	
10. What methodology should the OEB use to produce a return on equity that satisfies the Fair Return Standard (FRS)?	2.1 – 2.4, 4.1-4.7
11. Are the perspectives of debt and equity investors in the utility sector relevant to the setting of cost of capital parameters and capital structure? If yes, what are the perspectives relevant to that consideration, and how should those perspectives be	4.1-4.7

taken into account for setting cost of capital parameters and capital structure?

E.	**Capital Structure**	
12.	How should the capital structure be set for electricity transmitters, electricity distributors, natural gas utilities, and OPG to reflect the FRS?	3.5
13.	Should the OEB take a different approach for setting the capital structure for electricity transmitters depending on whether they are a single versus multiple asset transmitter?	3.5
F.	**<u>Mechanics of Implementation</u>**	
14.	What on-going monitoring indicators to test the reasonableness of the results generated by its cost of capital methodology should the OEB consider, including the monitoring of market conditions?	6.4.3
15.	How should the OEB regularly confirm that the FRS continues to be met and that rate-regulated entities are financially viable and have the opportunity to earn a fair, but not excessive, return?	6.4.3
16.	What should be the timing of the OEB's annual cost of capital parameters updates, including the timing, as required, of the underlying calculations?	4.7.7, 5.2.7
17.	What should be the defined interval (for example, every three to five years) to review the cost of capital policy (including, but not limited to, a review of the ROE formula and the capital structure)? Should the OEB adopt trigger mechanism(s) for a review and if so, what would be the mechanisms?	6.4.1
18.	How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one time basis upon rebasing or gradually over a rate term)?	6.3.1
19.	Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?	6.3.1
G.	**<u>Other Issues</u>**	
20.	Should the prescribed interest rates applicable to deferral and variance accounts ("DVAs") and the construction work in progress (CWIP) account for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be calculated using the current approach?	6.1-6.2
21.	If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?	6.1-6.2
22.	Should carrying charges and/or another type of rate apply to the Cloud Computing deferral account? If so, what rate should be applied?	6.5

APPENDIX B

SEC_COC_FinalArgument_AppendixB_20241107.xls

APPENDIX C

SEC_COC_FinalArgument_AppendixC_20241107.xls