ONTARIO ENERGY BOARD
COST OF CAPITAL REVIEW
EB-2024-0063

VECC COMPENDIUM
PANEL 1 - M1 LEI

September 26, 2024

TAB 1

- *beta* is the measure of asset risk (with the assumption that higher volatility in asset returns implies higher risk), i.e., a beta greater than 1 means the asset is more volatile than the market, and a beta less than 1 means it is less volatile;
- the *market risk premium* measures what investors, on average, demand as an extra return for investing in a portfolio relative to the risk-free asset for undertaking additional risk; and
- the *additional risk premium* measures risks beyond what standard CAPM captures.

Beta is a key component of CAPM that is intended to measure the systematic risk faced by a particular firm or sector, relative to the market. As such, considering beta and MRP together to determine the ERP (beta x MRP) provides a more accurate measure of returns required over the risk-free rate.

Although there are various ways to estimate beta for a publicly traded firm, this is typically estimated by regressing the firm's stock returns against the market returns. LEI believes the peer group needs to be representative of the business and financial risks faced by OEB-regulated entities. The peer groups determined by LEI for electricity generation, wires (electricity transmission/distribution) and gas transmission/distribution are presented earlier in Alternative #2. LEI has determined 1-year, 3-year and 5-year betas, with a preference for a 5-year beta, which tends to be more stable over time.

To estimate the beta, LEI utilized a three-step process:

(i) first, LEI used the raw beta for peer companies;

(ii) second, the raw betas were unlevered using the operating leverage of each of the peer companies (to diversify away the firm-specific unsystematic risk); and

(iii) finally, the average unlevered beta of the peer group was re-levered using the OEB allowed deemed capital structure.

LEI finds that un-levering the raw betas with the operating leverage of peer companies and re-levering the average un-levered beta with deemed operating leverage allowed by the OEB provides for a prudent estimate of beta. The results are shown in Figure 39 below.

TAB 2

electric and gas utilities (extracted from S&P Capital IQ) are considered the dependent variable, and 30-year US Treasury bond yields are considered the independent variable. The analysis yielded an adjustment factor of 0.39.

The utility bond spread adjustment factor was determined using a similar methodology as above. However, Moody's seasoned Baa corporate bond yields were considered the independent variable (in place of 30-year US Treasury bond yields).[308] The utility bond spread adjustment factor estimated using this approach worked out to 0.33.

2. Same as #1 but determining base ROE with the DCF approach instead of the ERP approach

The DCF method discounts the future stream of income that an asset or company is expected to generate. It is an attempt to estimate the present market value of a security based on its expected future earnings. The discount rate is the return on equity that equates the current price of the stock with the present value of its forecasted dividend stream. The DCF model estimates the present value of a stock using two variables - current dividend yield and the expected long-run growth in the firm's earning power, represented by expected growth in earnings per share ("EPS").

To shortlist the peer companies, LEI considered the following criteria:

1. The company stock is publicly traded in a recognized North American stock exchange; and
2. A certain percentage of the company's revenue or assets are from operations related to particular sectors:
    a. For generation peer companies, at least 70% from electricity generation
    b. For wires peer companies, at least 70% from electricity transmission /distribution
    c. For natural gas peer companies, at least 80% from natural gas transmission/distribution.

The resulting peer companies and the determination of DCF ROEs are shown in Figure 37 below (data is sourced from S&P Capital IQ). The average DCF ROE is determined separately for generation, wires (electricity transmission and distribution) and gas distribution sectors.

[308] For bonds, a seasoned issue is one that has been traded for longer than a year and has not experienced any repayment issues. Source: Investopedia.

TAB 3

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-10-VECC-41

Interrogatory

Reference:

Exhibit M1, pages 111, 113 and 117-119
Exhibit M2, pages 66 and 83

Preamble:

At page 113, LEI describes Alternative #4 for the ROE methodology as follows:

"Determination of base ROE using CAPM and adjustment of ROE using CAPM formula parameters".

At page 66, Concentric states:

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

And at page 83, Concentric states:

"With regard to beta, Concentric believes it is appropriate and consistent with empirical financial research to use Blume adjusted betas rather than raw betas for the reasons discussed earlier in our Report."

Question(s):

a) At page 111 the Report makes reference to average Blume-adjusted beta estimates from Value Line and Bloomberg using five years of data. Please confirm that, per Concentric's Report, LEI did not use Blume adjusted beta estimates. If confirm, please explain why LEI considers it appropriate to use raw, unadjusted betas versus Blume adjusted betas for purposes of the CAPM.

b) Please explain more fully why it is necessary to re-lever the betas.

c) Please provide a sample calculation illustrating how the raw betas are un-levered and then re-levered.

d) Please provide revised versions of Figures 40 and 41 based on the un-levered betas.

e) For purposes of its ROE analysis based on CAPM LEI relies on the re-levered 5-yr betas (Figure 40). However, the relative 5-year betas for electricity transmission/distribution and generation (0.67 and 0.64 respectively) suggest that electricity transmission/distribution requires a higher adjustment for risk than generation. Is this result, consistent with LEI's understanding as to the relative business and financial risks faced by electricity generation vs. electricity transmission/distribution? If not, why is it appropriate to rely on the 5-year betas?

Response: Note that this interrogatory response has been prepared by LEI.

a) LEI did not use Blume Adjustment as it inflates the beta estimates. The detailed reasoning is provided in LEI's response to IR #N-M1-0-SEC-3.

b) Un-levering beta removes the impact of a peer company's debt, theoretically isolating the business risk from financial risk. This gives a clearer picture of the inherent risk of the company's operations and allows for a fairer comparison between companies with different capital structures. Re-levering beta adjusts the un-levered beta to reflect the company's actual or target capital structure.

c) For peer companies, the raw beta is unlevered using the following formula: unlevered beta = levered beta ÷ [1 + (1 – tax rate) * (debt ÷ equity)]. For the calculations, LEI has used peer companies' average debt and equity for the last three years. Tax rate assumptions are based on the prevailing corporate tax rates in jurisdictions where the peer companies are headquartered.

   The average of unlevered betas is re-levered using the following formula: levered beta = unlevered beta × [1 + (1 – tax rate) × (debt ÷ equity)]. For the calculations, tax rate, debt, and equity inputs are for Ontario utilities.

d) Using un-levered betas to estimate the CAPM ROE is methodologically incorrect.

e) LEI generally expects electricity generation to have a slightly higher beta than electricity distribution/transmission if operating in a competitive wholesale market on a merchant basis. However, many generation companies have a significant proportion of their output under long term contracts. Generally, using a longer time horizon (5-year data) is more appropriate as it reduces the impact of short term market fluctuations. Further, results from data analysis should not be excluded just because they differ from expectations.

TAB 4

methodology to estimate the MRP. While some practitioners incorporate forward data into their equity return analysis, LEI believes forwards are too short-term and become less liquid in out years. LEI uses historical data, weighted towards more recent market experience.

The two other issues when considering MRP include the period of historical returns to consider and whether to consider MRP based on US or Canadian markets. In Figure 41 below, LEI has presented six options for considering MRP and the resulting CAPM ROE (utilizing a 5-year beta of 0.69 and a risk-free rate of 3.19%).

Figure 41. Six options for determining MRP and the resulting CAPM ROE for each option

MRP variables	Risk-free rate (R_f)	Beta	MRP	ERP (Beta * MRP)	CAPM ROE (R_f + ERP)
1928-2023 S&P 500 total returns - US 10-year treasury bond yields	3.19%	0.69	6.54%	4.53%	**7.72%**
1984-2023 S&P 500 total returns - US 30-year treasury bond yields			7.12%	4.92%	**8.11%**
1994-2023 S&P 500 total returns - US 30-year treasury bond yields			7.28%	5.03%	**8.23%**
2004-2023 S&P 500 total returns - US 30-year treasury bond yields			7.52%	5.20%	**8.39%**
2014-2023 S&P 500 total returns - US 30-year treasury bond yields			10.16%	7.03%	**10.22%**
2004-2023 S&P/TSX total returns - 30-year GoC bond yields			2.81%	1.94%	**5.14%**

Note: LEI's preferred CAPM ROEs are highlighted in green.

Sources: S&P Capital IQ, Statistics Canada, St. Louis Fed, NYU Stern.

LEI believes that CAPM ROE based on Canadian market data (5.14%) does not reflect investors' expected equity returns. The eight major pension funds in Canada (informally known as the Maple 8) allocate only about 25% of their portfolio to domestic Canadian investments, which indicates that investors are more likely to consider their MRP opportunity costs based on the US MRP.[314,315] As such, LEI prefers CAPM determined using US MRP.

Regarding the historical period to consider when determining the appropriate MRP, LEI prefers longer term averages (at least 10 years) as year over year MRP tends to be volatile (see Figure 42 below).

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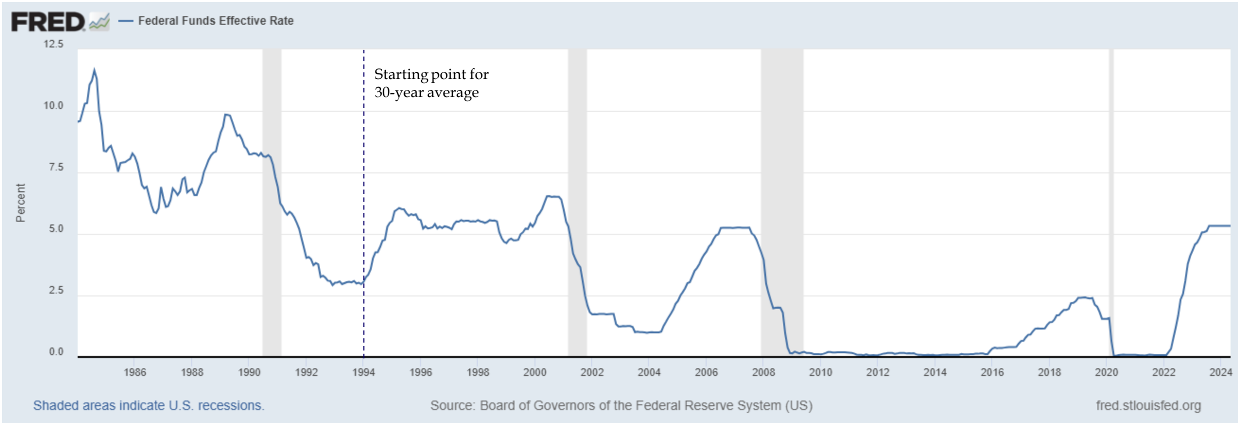
[314] Omers. Terms Explained: Pensions. November 12th, 2021.

[315] The Globe and Mail. Opinion: Pension funds need to seek out more investments in Canada. November 30th, 2023.

TAB 5

Figure 43. Fed policy rates (1984 – present)



Source: St. Louis Fed.

Notably, LEI's ERP estimate does not include 50 bps of transaction costs implicitly assumed in the 2009 ERP determination. As with LEI's recommendation for the treatment of transaction costs from debt issuances, LEI recommends considering the transaction costs associated with equity issuances as operating costs for similar reasons. Equity issuances do not happen with predictable regularity, which makes it more suitable to recover such costs as and when the utility incurs expenses.

Under this approach, the OEB may update the risk-free rate/LCBF annually. However, the beta and MRP are more stable and can be updated after five years. For instance, the US MRP recommended by Kroll (formerly Duff & Phelps) has ranged between 5% and 6% since 2008 (Kroll has updated the recommended MRP 33 times during this period).

Alternatively, the OEB can update the LCBF and ERP annually, using the same beta for five years. Kroll regularly updates their ERP recommendations for the US (when warranted).[317] Effective June 8th, 2023 (to remain until further updates), Kroll recommended an ERP of 5.5% for the US (assuming a beta of 1). Kroll estimates the ERP based on historical market returns starting from 1963 (compared with US 20-year bond returns).[318]

5. Determination of base ROE using CAPM, with ROE updated annually using adjustment factors determined in #3

The OEB may determine the base ROE using CAPM (alternative #4). LEI believes that the mean CAPM ROE of 8.95% is a reasonable estimate for the base ROE. The base ROE may be updated

[317] Kroll. Kroll Recommended U.S. Equity Risk Premium (ERP) and Corresponding Risk-free Rates (R_f); January 2008–Present. Accessed on May 20th, 2024.

[318] Kroll. Proper Application of the Duff & Phelps ERP Adjustment. May/June 2011.

TAB 6

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

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

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

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

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

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

TAB 7

limitations of a single approach. Instead, it uses basic economic cost-of-equity models that are common in regulation, investments, and valuations; it is prospective where possible rather than based on historical data; and it does not incorrectly attribute a country risk premium to the US versus Canada.

We turn first to the issue of the relevant market for capital for Ontario service providers, insofar as this informs the entirety of our analysis as well as our criticism of LEI's CAPM analysis.

B. The Canadian and US Capital Markets are Integrated into a Single North American Capital Market

1. Explanation of the Issue and Why it is Important to this Proceeding

We conclude that capital relevant to the Ontario electric service providers ultimately comes from a single, integrated North American capital market. This conclusion is important for two reasons. First, the conclusion that the markets are integrated provides the basis for our selection of risk-comparable firms from the pool of North American electric utilities. Second, the conclusion is the basis for determining that LEI errs in its application of the CAPM to its base cost of equity result and to the annual adjustment mechanism.

Our conclusions regarding capital market integration are consistent with the 2009 Board Report, which concluded that Canada and the US capital markets were one-and-the-same, and accepted the use of selected US electric utilities as firms of comparable risk ("comparables") to the target firms.[38]

Ontario electricity distributors must raise capital funds from somewhere and it is important to understand how scarce funds are allocated in the market.

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[38] 2009 Report, p. 22 accepting the Concentric Economics approach to winnowing the field of US-based electric service providers.

TAB 8

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-10-VECC-44

Interrogatory

Reference:

Exhibit M1, pages 122-123

Preamble:

LEI describes Alternative #5 as follows:

“Determination of base ROE using CAPM, with ROE updated annually using adjustment factors determined in #3.”

“Using the base LCBF of 3.19% (see Figure 41) and the base utility bond spread determined as of March 2024 (see Figure 44 below), the Annual ROE formula (for year “t”) will be as follows:

$ROE_t = 8.95\% + 0.26 \times (LCBF_t - 3.19\%) + 0.13 \times (UtilBondSpread_t – 1.385\%)$”.

Question(s):

a) What is the assumed base year for the formulae?

b) All of the values used in the formulae do not appear to reflect the same base year” as: i) the 8.95% and the 3.19% are based on 2025 whereas ii) the UtilBondSpread is based on 2024 data. Please reconcile.

Response: Note that this interrogatory response has been prepared by LEI.

a) LEI understands that the base ROE, base LCBF, and base utility bond spreads determined in this proceeding (with updated data as of September 2024) will be used as inputs to update the authorized ROE annually for the years 2025-2029. This implies a base year of 2024.

b) To the best of LEI’s knowledge, there are no 2025 forecasts available for utility bond spreads. As such, the utility bond spread is estimated based on recently available 2024 data (LEI recommends updating this as of September 2024).

TAB 9

All major Canadian banks provide forecasts for 30-year GoC bond yield on a quarterly or monthly basis (see Figure 26). In the illustrative sample, the average forecast yield for 2025 is 3.19%. Similar to Alternative #1, to estimate the spread over LCBF for an A-rated utility, a 12-month trailing average of Bloomberg's BVCAUA30 BVLI Index can be used. The OEB can consider the latest available forecasts as of September 30th each year.

Figure 26. 30-year GoC bond yield forecasts (illustrative; list not exhaustive)

Entity	Forecast date	Yield	2024			2025			
			Q2	Q3	Q4	Q1	Q2	Q3	Q4
Bank of Montreal ("BMO")	March 25th, 2024	30-year GoC bond	3.33%	3.30%	3.25%	3.20%	3.20%	3.20%	3.15%
Canadian Imperial Bank of Commerce ("CIBC")	April 24th, 2024		3.50%	3.45%	3.35%	3.30%	3.20%	3.15%	3.35%
Desjardins	May 16th, 2024		3.55%	3.45%	3.25%	3.10%	2.85%	2.85%	2.75%
National Bank of Canada ("National Bank")	May 2024		3.50%	3.45%	3.35%	3.15%	3.15%	3.15%	3.15%
Royal Bank of Canada ("RBC")	March 12th, 2024		3.25%	3.15%	3.05%	3.00%	3.05%	3.10%	3.15%
Scotiabank	April 18th, 2024		3.60%	3.50%	3.50%	3.45%	3.50%	3.50%	3.50%
Toronto Dominion ("TD") Bank	March 20th, 2024		3.75%	3.65%	3.55%	3.45%	3.35%	3.25%	3.20%
Average			**3.50%**	**3.42%**	**3.33%**	**3.24%**	**3.19%**	**3.17%**	**3.18%**

Sources: Desjardins, Scotiabank, TD Bank, BMO, RBC, National Bank, and CIBC.

Application of DLTDR methodology

With respect to the application of the DLTDR methodology, the OEB can choose from the following options:

1. **Status-quo**: As described in Section 4.6.1, the DLTDR currently only applies to electricity distributors and transmitters.
2. **Modified status quo approach with the DLTDR as a cap, but uniformly applicable for all utilities** (not just electricity distribution and transmission)
3. **Uniform application of the DLTDR for all utilities (no actual/embedded rate to be considered)**: For fixed-rate debt, the DLTDR is to be considered for the year of issuance;[241] the latest DLTDR is to be considered for variable-rate loans.

4.7.2 Recommendations

LEI recommends considering reputable publicly available sources for 30-year bond forecasts for LCBF/risk-free rate. As highlighted in the preceding section, this eliminates the need to calculate 30-year vs. 10-year bond yield spreads and is easily verifiable due to the public availability of forecasts. As such, it is simple to administer relative to the status quo and more transparent,

[241] For example, DLTDR approved for 2019 will be considered for the maturity term if the debt was issued in 2019.

TAB 10

Potential alternatives for ROE determination

The OEB may consider the following options for ROE methodology:

1. Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads, and adjustment factors based on current data;
2. Same as #1 but determining base ROE with the discounted cash flow ("DCF") approach instead of the ERP approach;
3. Same as #1 but determination of adjustment factors using multivariate regression analysis;
4. Determination of base ROE using CAPM and adjustment of ROE using CAPM formula parameters;
5. Determination of base ROE using CAPM, with ROE updated annually using adjustment factors determined in #3; and
6. Determination of an average base ROE from CAPM, ERP and DCF methodologies, with annual updating of ROE based on #3.

In subsequent paragraphs, LEI has discussed the above alternatives in more detail.

1. Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads and adjustment factors based on current data

LEI analyzed the historical premiums observed between 30-year GoC bond yields and returns from the S&P/TSX composite index (total returns, including dividend returns) and from the BMO equal weight utilities index ETF to determine base ROE based on the ERP approach. This is similar to Dr. J.H. Vander Weide's ERP approach in EB-2009-0084. This approach, using current data, yielded an ERP of 5.94% (as presented in Figure 36).

Figure 36. Determination of updated ERP

Comparable group	Period of analysis	Average stock return	Average bond yield	ERP
S&P/TSX composite (total return) index	2001-2024	6.77%	3.37%	3.40%
BMO equal weight utilities index ETF	2010-2024	10.98%	2.50%	8.48%
Average				**5.94%**

Sources: S&P Capital IQ, Bloomberg, BMO.

The base LCBF using March 2024 data is 3.15%. As such, the base ROE is 9.09% (3.15% + 5.94%) using the existing methodology.

To determine the LCBF adjustment factor, LEI used regression analysis for the 2001 to 2023 period. To maximize the data points for regression analysis, LEI utilized quarterly data instead of annual data (see Appendix 7). The weighted average ROEs allowed by US regulators for

TAB 11

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-10-VECC-36

Interrogatory

Reference:

Exhibit M1, pages 113-114

Preamble:

LEI describes Alternative #1 for the ROE methodology as follows:

"Status quo with updated values for base ROE (using ERP approach), base LCBF, base utility bond spreads, and adjustment factors based on current data."

And

"The base LCBF using March 2024 data is 3.15%. As such, the base ROE is 8.65% (3.15% + 5.50%) using the existing methodology."

Question(s):

a) With respect to Figure 36, how was the average bond yield value calculated for each of the two periods: i) 2001-2024 and ii) 2010-2024 and is it just coincidence that the values are the same (i.e., 3.37%)?

b) In EB-2009-0084 did Dr. Vander Weide use historical premiums observed between 30-year GoC bond yields and both: i) returns from the S&P/TSX composite index (total returns, including dividend returns) and ii) from the BMO equal weight utilities index ETF to determine the base ROE for the ERP approach?

c) With respect to Figure 36, please provide a revised version with two additional rows: i) Use the S&P/TSX composite (total return) index results for the period 2010 to 2024 and ii) Use the BMO equal weight utilities index ETF results for the period 2001-2024. Note: If the BMO equal weight utilities index ETF does not have values back to 2001, please provide two rows where: i) the first provides the BMO equal weight utilities index ETF results from its starting year to 2024 and ii) second provides the S&P/TSX composite (total return) index results based on the same period.

d) Is 2024 the "base year" for the calculated base ROE of 8.65%? If not why not and what is the associated base year?

e) With respect to Alternative #1, please set out the formula that would be used to calculate the ROE in future years.

Response: Note that this interrogatory response has been prepared by LEI.

a) LEI inadvertently considered average bond yields as 3.37% for both periods. The corrected calculations are provided below:

Comparable group	Period of study	Average stock return	Average bond yield	ERP
S&P/TSX utilities	2001-2024	6.77%	3.37%	3.40%
BMO utilities	2010-2024	10.98%	2.50%	8.48%
Average				**5.94%**

b) Dr. Weide used the historical data on ROEs in S&P/TSX utilities stock index with the period of study between 1956 – 2008 and a basket of Canadian utility stocks created by the BMO CM with the period of study between 1983 – 2008.[8]

c) The BMO equal-weight utilities index ETF was launched on January 20th, 2010, with an average return of 10.98% as of May 14th, 2024. Therefore, LEI added a row showing the average return of the S&P/TSX composite (total return) index from January 20th, 2010, to May 14th, 2024. The resulting average ERP is 5.1%.

Comparable group	Period of study	Average stock return	Average bond yield	ERP
S&P/TSX utilities	2001-2024	6.77%	3.37%	3.40%
S&P/TSX utilities	2010-2024	5.91%	2.50%	3.41%
BMO utilities	2010-2024	10.98%	2.50%	8.48%
Average				**5.10%**

d) 2024 is the “base year” for the calculated base ROE of 9.09% (updated after accounting for the change discussed in a)).

e) $ROE_t = 9.09\% + 0.39 \times (LCBF_t - 3.15\%) + 0.33 \times (UtilBondSpread_t – 1.385\%)$

[8] Union Gas Inc. Appendix A to response to questions raised as issues for discussion at stakeholder conference. September 8th, 2009.

TAB 12

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-10-VECC-42

Interrogatory

Reference:

Exhibit M1, pages 115 and 118

Question(s):

a) Please explain why Figure 39 (which derives the beta values for electricity generation, wires (electricity transmission/distribution) and gas transmission/distribution for purposes of the CAPM) includes as peers, companies that are not used as peers in Figure 37 (for purposes of the DCF model).

b) Please re-do Figures 39, 40 and 41 using only those companies included in Figure 37 for purposes of determining the beta values.

Response: Note that this interrogatory response has been prepared by LEI.

a) The reasoning for excluding some peer companies is provided as a note in Figure 37. The note is reproduced here for reference: *“LEI has excluded some outlier companies from the generation peer group due to very high or very low 2024-2026 annual EPS growth estimates that resulted in implausible estimates of DCF ROE for the generation peer group. The excluded companies include Brookfield Renewable Corporation, Clearway Energy, Inc., Innergex Renewable Energy Inc., Northland Power Inc., and TransAlta Corporation. Others, such as Talen Energy, lacked sufficient historical data.”*

b) Please see LEI response in a).

TAB 13

Issue #	Issue	Status quo	LEI recommendation
9	What are the implications of variances from the deemed capital structure (i.e., notional debt and equity) and how should they be considered in setting the cost of long-term debt?	• The OEB considers the deemed capital structure when determining the cost of capital • For short-term debt, the OEB considers 4% for electricity distributors and transmitters and the unfunded portion of the capital structure for other utilities	The status-quo approach (considering deemed capital structure regardless of the actual capital structure) is retained
	D. Return on equity		
10	What methodology should the OEB use to produce a return on equity that satisfies the Fair Return Standard (FRS)?	• The base ROE was determined using the equity risk premium ("ERP") approach in 2009 • The ROE is updated annually using adjustment factors for long Canada bond forecast ("LCBF") and A-rated utility bond yield spread	• LEI recommends using the Capital Asset Pricing Model ("CAPM") to determine the base ROE (average estimate of 8.95%, low estimate of 8.23%, and a high estimate of 10.22%), as it meets the FRS • The ROE should be updated annually using the adjustment factors (0.26 for LCBF and 0.13 for utility bond spread) determined simultaneously with multivariate regression analysis (as opposed to independent determination in 2009)
11	Are the perspectives of debt and equity investors in the utility sector relevant to the setting of cost of capital parameters and capital structure? If yes, what are the perspectives relevant to that consideration, and how should those perspectives be taken into account for setting cost of capital parameters and capital structure?	• The allowed ROEs are legally required to meet the FRS, which is inherently designed to allow sufficient returns for the commensurate risk undertaken by the investors and ensure that the utilities continue to attract incremental capital at reasonable terms • The DLTDR and DSTDR formulae are devised considering OEB-regulated entities' credit profiles	• The OEB's current approach to cost of capital determination (including the determination of deemed capital structure) sufficiently considers investor perspectives, i.e., the allowed cost is commensurate with the perceived risks associated with the sector. • LEI believes that the existing approach meets the FRS.
	E. Capital structure		

TAB 14

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-10-VECC-40

Interrogatory

Reference:

Exhibit M1, page 116

Preamble:

At page 116, LEI states:

"Considering the two variables simultaneously (the weighted average ROEs allowed by US regulators for electric and gas utilities as the dependent variable; 30-year GoC government bond yields and Moody's seasoned Baa corporate bond yields as independent variables) using multivariate regression analysis lowers the adjustment factors for each variable, i.e., 0.26 for the LCBF adjustment factor and 0.13 for the utility bond spread adjustment factor."

At page 118 (Figure 69), LEI provides the actual regression results and lists US 30-year Treasury bonds as one of the independent variables.

Question(s):

a) At page 116 the Report indicates that 30-year GoC government bond yields were used as one of the independent variables. However, in Figure 69, the independent variable is indicated to be US 30-year Treasury bonds. Please reconcile and indicate which government's bonds were used in the regression analysis.

b) Using LEI's regression equation, the current Moody's seasoned Baa corporate bond yields and the current yields for the appropriate government's 30-year bond what is the resulting ROE?

c) If US 30-year Treasury bonds were used as the independent variable, please re-estimate the equation using 30-year GoC government bond yields instead and provide the results. Using this revised equation, the current Moody's seasoned Baa corporate bond yields and the current 30-year GoC government bond yields, what is the resulting ROE?

Response: Note that this interrogatory response has been prepared by LEI.

a) LEI performed regression analyses using US data to determine the adjustment factors of LCBF and A-rated utility bond yields. The reference to 30-year GoC government bond yields on page 116 of the LEI report is a typographical error.

b) The purpose of this regression analysis was to determine the appropriate adjustment factors, not estimating ROE.

c) Please see the answer in b) above.

TAB 15

LEI recommendations – Issue 19

Consistent with the OEB's existing policy, the OEB should continue to implement changes in the cost of capital parameters and capital structure upon rebasing. However, to ensure the FRS continues to be met, the OEB should also introduce an option for parties to request implementation of such changes prior to rebasing, so long as the two-factor test is met – (i) the utility should have more than 60% of its rate term remaining, and (ii) deviations in the cost of capital parameters should be material (100 bps or more).

4.20 Prescribed interest rates – appropriateness of existing methodology

Issue 20 in the Final Issues List is stated in the textbox below.[422]

Issue 20: ***Should the prescribed interest rates applicable to DVAs and the construction work in progress (CWIP) account for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be calculated using the current approach?***

4.20.1 Status quo

As described previously in Section 2, the OEB uses a formulaic approach to setting prescribed interest rates for Ontario electricity distributors, natural gas utilities, and other rate or payment amounts regulated entities for regulatory accounts under the Uniform System of Accounts. The formulaic approach was approved in 2006, with the intent of establishing an accounting interest methodology that could be updated automatically, while also being reflective of market rates and responsive to changes in market conditions.[423]

The prescribed interest rates are set for two types of accounts:[424]

- **deferral and variance accounts ("DVAs"):** DVAs are commonly used regulatory tools that allow a utility an opportunity to address costs that were unknown or uncertain when

requirement; for distributors with a revenue requirement greater than $200 million, the materiality threshold is set at $1 million. As another example, in the context of the Global Adjustment ("GA") DVAs, materiality is defined such that "*any unexplained discrepancy between the actual and expected balance that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation*." (Source: OEB. *Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications (Chapter 2: Cost of Service).* December 15, 2022)

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

[423] OEB. *EB-2006-0117, Approval of Accounting Interest Rates Methodology for Regulatory Accounts.* November 28, 2006.

[424] Ibid.

TAB 16

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-20-VECC-57

Interrogatory

Reference:

Exhibit M1, page 163

Preamble:

At page 163, LEI states:

"LEI recommendations – Issue 19

Consistent with the OEB's existing policy, the OEB should continue to implement changes in the cost of capital parameters and capital structure upon rebasing. However, to ensure the FRS continues to be met, the OEB should also introduce an option for parties to request implementation of such changes prior to rebasing, so long as the two-factor test is met – (i) the utility should have more than 60% of its rate term remaining, and (ii) deviations in the cost of capital parameters should be material (100 bps or more)."

Question(s):

a) Please explain how the 100 bps materiality threshold applies in the case of a change in capital structure (e.g., would a change from an equity thickness of 40% to 41% be considered a 100 bps change?).

b) How is the 100 bps materiality threshold to be applied if both the ROE and equity thickness are changed but neither change meets the 100 bps threshold?

c) How is the 100 bps materiality threshold to be applied if the ROE is increased but the equity thickness decreased (or vice-versa)?

Response: Note that this interrogatory response has been prepared by LEI.

a) Please refer to LEI response in IR #N-M1-18-VECC-56. The 100 bps materiality threshold in LEI recommendation only applies to the ROE, not to capital structure.

b) Please see LEI response in a) above.

c) Please see LEI response in a) above.

TAB 17

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-6-VECC-2

Interrogatory

Reference:

Exhibit M1, pages 27-28 and 84

Preamble:

At page 27, LEI states:

“For natural gas distributors, and OPG’s prescribed rate-regulated baseload generation, the long-term debt rates are considered based on the weighted cost of actual embedded debt.

For electricity distributors and transmitters, the OEB’s stated policy is to primarily rely on embedded or actual cost for existing long-term debt instruments, albeit with DLTDR acting as a proxy (if the distributor has no debt) or a ceiling (if the actual rate is higher than DLTDR).

The OEB utilizes the long-term debt rate for 56% of the capital structure for electricity distributors and transmitters.”

At page 28, LEI states:

“For natural gas distributors and OPG’s prescribed rate-regulated baseload generation, the short-term debt rates are considered based on the weighted cost of actual embedded debt. The short-term debt is used for an unfunded portion to true-up the deemed capitalization to the utility’s actual capitalization and is typically a small fraction of total capitalization for rate-setting purposes.”

At page 84 the Report outlines the use of the DLTDR when an electric distribution utility has no debt or the debt is held by an affiliate.

Question(s):

a) For electricity distributors and transmitters, if the actual embedded debt is less than 56% of the capital structure, what does the OEB use as the long-term debt rate for the that portion of the rate base that is deemed to be financed by long-term debt? Please provide the relevant references supporting LEI’s understanding of the OEB’s current approach.

b) For electricity distributors and transmitters, what role (if any) does the DLTDR currently play in determining the regulated rate for long term debt if the debt is not held by an affiliate?

Response: Note that this interrogatory response has been prepared by LEI.

a) Please refer to the 2016 OEB Staff Report in EB-2009-0084:

"Notional debt can be either positive (i.e. deemed debt is greater than actual debt) or negative (where deemed debt is less than actual debt). Since the factors which cause notional debt to arise are largely under the control of the utility, the OEB has determined in a number of cases that notional debt should attract the weighted average cost of actual long-term debt rate rather than the deemed long-term debt rate issued by the OEB.4 An exception to this is where a utility is 100% equity financed and has no current debt or recent history of debt financing. In such a circumstance, the OEB has noted that the deemed long-term debt rate should apply as a ceiling."

b) LEI has summarized its understanding of the OEB's current DLTDR guidelines in page 84 of the LEI report. The relevant portion is reproduced below. Only the second bullet point refers to "debt held by an affiliated party"; the rest applies for debt not held by an affiliate.

"For electricity distributors and electricity transmitters, the OEB's stated policy is to primarily rely on embedded or actual cost for existing long-term debt instruments, albeit with DLTDR acting as a proxy (if the distributor has no debt) or a ceiling (if the actual rate is higher than DLTDR). In particular, these circumstances include:

- *The DLTDR will be used as a proxy for long-term debt rate where an electricity distribution utility has no actual debt;*
- *For debt held by an affiliated party with a fixed rate, the DLTDR at the time of issuance will be used as a ceiling on the rate allowed for that debt (e.g., DLTDR approved for 2019 will be considered for the maturity term if the debt was issued in 2019);*
- *For debt with a variable rate, the DLTDR will be a ceiling on the rate allowed for that debt; This applies whether the debt holder is an affiliate or a third-party.*
- *For debt that is callable on demand (within the test year period), the current DLTDR will be a ceiling on the rate allowed for that debt; and*

  For debt that is callable, but not within the test year period, it will have its debt cost considered as if it is not callable. As such, the debt cost will be treated in accordance with other guidelines pertaining to actual, affiliated or variable-rate debt."

Table 5-11 - OEB Appendix 2-OB 2021 Actual Loan Schedule

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Term Loan Payable 9214932-02 - 3.38%	TD Bank	Third Party	Fixed	1-Aug-12	10	$ 2,562,231	0.0338	$ 87,139.53
2	Term Loan Payable 3.40%, interest only	TD Bank	Third Party	Fixed	1-Dec-17	5	$ 2,500,000	0.034	$ 85,000.00
3	Term Loan Payable - 4.20%	TD Bank	Third Party	Fixed	2-Jan-19	10	$ 1,880,608	0.042	$ 79,068.99
4	Term Loan Payable - 3.60%	TD Bank	Third Party	Fixed	31-Mar-17	10	$ 1,768,271	0.036	$ 63,740.88
5	Term Loan Payable 9214932-12- 3.54%	TD Bank	Third Party	Fixed	19-Apr-19	20	$ 3,440,863	0.0354	$ 121,944.87
6	Term Loan Payable - 2.58% renewable	TD Bank	Third Party	Fixed	3-Feb-21	5	$ 959,733	0.0258	$ 24,755.07
7	Term Loan Payable 9214932-04 - 3.62%	TD Bank	Third Party	Fixed	1-Dec-21	5	$ 1,000,000	0.0362	$ 3,173.70
Total							$ 14,111,707	3.29%	$ 464,823.04

Table 5-12 - OEB Appendix 2-OB 2022 Actual Loan Schedule

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Term Loan Payable 9214932-02 - 3.38%	TD Bank	Third Party	Fixed	1-Aug-12	10		0.0338	$ 50,809.93
2	Term Loan Payable 9214932-02 -4.866%	TD Bank	Third Party	Fixed	1-Aug-22	5	$ 2,226,459	0.04866	$ 35,955.02
3	Term Loan Payable 3.40%, interest only	TD Bank	Third Party	Fixed	1-Dec-17	5		0.034	$ 76,736.74
4	Term Loan Payable 5.007%, P 13888.89+i	TD Bank	Third Party	Fixed	1-Dec-22	5	$ 2,451,389	0.05007	$ 10,014.64
5	Term Loan Payable - 4.20%	TD Bank	Third Party	Fixed	2-Jan-19	10	$ 1,829,246	0.042	$ 76,915.85
6	Term Loan Payable - 3.60%	TD Bank	Third Party	Fixed	31-Mar-17	10	$ 1,709,545	0.036	$ 61,630.13
7	Term Loan Payable 9214932-12- 3.54%	TD Bank	Third Party	Fixed	19-Apr-19	20	$ 3,340,232	0.0354	$ 118,402.79
8	Term Loan Payable - 2.58% renewable	TD Bank	Third Party	Fixed	3-Feb-21	5	$ 931,234	0.0258	$ 24,055.46
9	Term Loan Payable 9214932-13 - 4.922%	TD Bank	Third Party	Fixed	8-Sep-22	5	$ 2,993,122	0.04922	$ 50,088.46
10	Term Loan Payable 9214932-04 - 3.62%	TD Bank	Third Party	Fixed	1-Dec-21	5	$ 986,481	0.0362	$ 35,712.08
Total							$ 16,467,707	3.28%	$ 540,321.10

Table 5-13 - OEB Appendix 2-OB 2023 Bridge Loan Schedule

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Term Loan Payable 9214932-02 -4.866%	TD Bank	Third Party	Fixed	1-Aug-22	5	$ 2,030,188	0.04866	$ 99,113.52
2	Term Loan Payable 5.007%, P 13888.89+i	TD Bank	Third Party	Fixed	1-Dec-22	5	$ 2,342,536	0.05007	$ 109,719.57
3	Term Loan Payable - 4.20%	TD Bank	Third Party	Fixed	2-Jan-19	10	$ 1,775,684	0.042	$ 74,670.52
4	Term Loan Payable - 3.60%	TD Bank	Third Party	Fixed	31-Mar-17	10	$ 1,648,669	0.036	$ 59,442.12
5	Term Loan Payable 9214932-12- 3.54%	TD Bank	Third Party	Fixed	19-Apr-19	20	$ 3,235,988	0.0354	$ 114,720.79
6	Term Loan Payable - 2.58% renewable	TD Bank	Third Party	Fixed	3-Feb-21	5	$ 902,009	0.0258	$ 23,302.30
7	Term Loan Payable 9214932-13 - 4.922%	TD Bank	Third Party	Fixed	8-Sep-22	5	$ 2,963,449	0.04922	$ 145,942.90
8	Term Loan Payable 9214932-04 - 3.62%	TD Bank	Third Party	Fixed	1-Dec-21	5	$ 959,928	0.0362	$ 34,786.71
Total							$ 15,858,451	4.17%	$ 661,698.43

Table 5-14 - OEB Appendix 2-OB 2024 Test Loan Schedule

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Term Loan Payable 9214932-02 -4.866%	TD Bank	Third Party	Fixed	1-Aug-12	5	$ 1,927,367	0.04866	$ 94,653.23
2	Term Loan Payable 3.40%, interest only	TD Bank	Third Party	Fixed	1-Dec-22	5	$ 2,220,591	0.05007	$ 111,740.73
3	Term Loan Payable - 4.20%	TD Bank	Third Party	Fixed	2-Jan-19	10	$ 1,719,933	0.042	$ 72,536.88
4	Term Loan Payable - 3.60%	TD Bank	Third Party	Fixed	31-Mar-17	10	$ 1,585,647	0.036	$ 57,337.94
5	Term Loan Payable 9214932-12- 3.54%/5.:	TD Bank	Third Party	Fixed	19-Apr-19	20	$ 3,150,302	0.0354	$ 153,848.04
6	Term Loan Payable - 2.58% renewable	TD Bank	Third Party	Fixed	3-Feb-21	5	$ 872,052	0.0258	$ 22,593.37
7	Term Loan Payable 9214932-13 - 4.922%	TD Bank	Third Party	Fixed	8-Sep-22	5	$ 2,916,918	0.04922	$ 144,060.36
8	Term Loan Payable 9214932-04 - 3.62%	TD Bank	Third Party	Fixed	1-Dec-21	5	$ 933,430	0.0362	$ 33,923.86
9	Budgeted Term Loan	TD Bank	Third Party	Fixed	31-May-24	5	$ 743,954	0.053	$ 39,636.41
Total							$ 16,070,196	4.54%	$ 730,330.81

5.1.4 VARIANCE ANALYSIS OF CAPITAL STRUCTURE

Year: 2021

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (Years)	Average Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments (if any)
Shareholder Loan	City of Stratford	Affiliated	Fixed Rate	11/1/2000	Demand	15,600,000	4.77%	744,120	
Infrastructure Loan 01	RBC	Third-Party	Fixed Rate	12/15/2010	15	406,607	4.40%	76,220	paid off early and replaced
Infrastructure Loan 02	RBC	Third-Party	Fixed Rate	4/1/2011	15	61,712	3.98%	8,584	paid off early and replaced
Swap Loan	RBC	Third-Party	Fixed Rate	5/31/2013	25	10,624,667	3.35%	355,926	
Bank Loan	RBC	Third-Party	Fixed Rate	11/4/2021	4	900,000	0.22%	1,965	to replace IO loans
Total						27,592,986	4.30%	1,186,815	

Year: 2022

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (Years)	Average Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments (if any)
Shareholder Loan	City of Stratford	Affiliated	Fixed Rate	11/1/2000	Demand	15,600,000	4.77%	744,120	
Swap Loan	RBC	Third-Party	Fixed Rate	5/31/2013	25	10,142,500	3.35%	339,774	
Bank Loan	RBC	Third-Party	Fixed Rate	11/4/2021	4	783,335	2.62%	20,523	to replace IO loans
Total						26,525,835	4.16%	1,104,417	

Year: 2023

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (Years)	Average Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments (if any)
Shareholder Loan	City of Stratford	Affiliated	Fixed Rate	11/1/2000	Demand	15,600,000	4.77%	744,120	
Bank Loan	RBC	Third-Party	Fixed Rate	11/4/2021	4	563,996	2.62%	14,777	
Swap Loan # 1	RBC	Third-Party	Fixed Rate	5/31/2013	25	9,644,583	3.35%	323,094	
Swap Loan # 2	RBC	Third-Party	Fixed Rate	12/31/2024	25	2,500,000	4.92%	123,000	
Total						28,308,579	4.26%	1,204,990	

Year: 2024

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (Years)	Average Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments (if any)
Shareholder Loan	City of Stratford	Affiliated	Fixed Rate	11/1/2000	Demand	15,600,000	4.77%	744,120	
Bank Loan	RBC	Third-Party	Fixed Rate	11/4/2021	4	338,840	2.62%	8,878	
Swap Loan # 1	RBC	Third-Party	Fixed Rate	5/31/2013	25	9,131,667	4.74%	432,841	
Swap Loan # 2	RBC	Third-Party	Fixed Rate	12/31/2024	25	5,000,000	7.22%	361,000	
Total						30,070,507	5.14%	1,546,839	

Year: 2025

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (Years)	Average Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments (if any)
Shareholder Loan	City of Stratford	Affiliated	Fixed Rate	11/1/2000	Demand	15,600,000	4.58%	714,480	
Bank Loan	RBC	Third-Party	Fixed Rate	11/4/2021	4	107,715	2.62%	2,822	
Swap Loan #1	RBC	Third-Party	Fixed Rate	5/31/2013	25	8,601,500	4.74%	407,711	
Swap Loan #2	RBC	Third-Party	Fixed Rate	12/31/2024	25	4,813,816	4.02%	193,515	
New Loan	RBC	Third-Party	Fixed Rate	1/1/2025	25	4,875,800	6.05%	294,986	
Total						33,998,831	4.75%	1,613,515	

Notional Debt

FHI's deemed and actual long-term debt are different. For the 2025 Test Year, the actual amount of Long Term Debt is $33,998,831 (Table 5-3) and the deemed Long Term Debt is $40,417,230 (Table 5-2). Therefore, FHI has a positive notional debt of $6,478,317.

Year 2019									
Row	**Description**	**Lender**	**Affiliated or Third-Party Debt?**	**Fixed or Variable-Rate?**	**Start Date**	**Term (years)**	**Principal ($)**	**Rate (%) (Note 2)**	**Interest ($) (Note 1)**
1	Loan from Shareholders	Various	Affiliated	Fixed Rate		N/A	$ 5,260,461	4.12%	$ 216,730.98
2	Bank Swap #1	CIBC	Third-Party	Fixed Rate	12/28/2011	10	$ 1,317,512	4.050%	$ 53,359.24
3	Bank Swap #2	CIBC	Third-Party	Fixed Rate	01/01/2012	15	$ 1,227,659	4.900%	$ 60,155.29
4	Bank Swap #3	CIBC	Third-Party	Fixed Rate	06/30/2011	10	$ 1,980,685	4.050%	$ 80,217.74
5	Bank Swap #4	CIBC	Third-Party	Fixed Rate	08/19/2013	15	$ 1,499,443	4.250%	$ 63,726.33
6	Bank Swap #5	CIBC	Third-Party	Fixed Rate	06/12/2014	15	$ 2,116,373	4.250%	$ 89,945.85
7	Bank Swap #6	CIBC	Third-Party	Fixed Rate	07/01/2017	15	$ 1,666,667	4.250%	$ 70,833.35
8	Bank Swap #7	CIBC	Third-Party	Fixed Rate	03/01/2018	15	$ 3,511,111	4.250%	$ 149,222.22
9	Bank Swap #8	CIBC	Third-Party	Fixed Rate	01/01/2019	15	$ 3,733,333	4.250%	$ 158,666.65
Total							**$ 22,313,244**	**0.042255517**	**$ 942,857.65**

TAB 18

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-6-VECC-29

Interrogatory

Reference:

Exhibit M1, page 89, Figure 24

Preamble:

At page 89, Figure 24 shows:

Figure 24. Summary of the jurisdictional review (long-term debt determination)

Jurisdiction	Approach to determining allowed cost of debt	Description
Australia	Formulaic	• Simple average of a benchmark debt portfolio with a credit rating of BBB+ for existing NSPs • On-the-day cost of debt as at end of December 2022 for new NSPs
California	Case by case	Based on actual or embedded costs of long-term debt
New York	Case by case	Based on actual or embedded costs of long-term debt
United Kingdom	Formulaic	• Indexation of the cost of debt allowance using the yield of the iBoxx GBP Utilities 10yr+ index • Addition of additional costs of borrowing and infrequent issuer premium • Calibration of the index • Deflation to CPIH real yields

Question:

LEI recommends the Board continue with its current methodology for DLTDR which uses an embedded cost of debt. While the calculation of the different methodologies are explained in detail no analysis is provided as to the merits of employing what appear to be two different regulatory philosophies – one using embedded (actual) debt and the other calculating a "debt cost proxy" via a formulaic approach. What are the advantages and disadvantages of these two methods and why is one method to be preferred over the other?

Response: Note that this interrogatory response has been prepared by LEI.

While the debt cost proxy approach sets a benchmark for utilities to meet, it also may or may not be fully reflective of market conditions. Ontario's hybrid approach allows for relatively small deviations between utilities while retaining the benchmark as a cap. Customers benefit when rates are lower than the cap. While LEI finds benchmark approaches to be a reasonable approach to setting the cost of debt, LEI does not see a compelling reason to move away from current practice.

TAB 19

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-3-VECC-19

Interrogatory

Reference:

Exhibit M1, pages 67-68

Question:

LEI makes the observation that changing rate design to increase the recovery of distribution cost via a fixed rate component, as compared to a volumetric charge, reduces volumetric risk. The Report also notes that predictability of cash flow is considered by utility debt rater agencies. What study has LEI done in order to understand the magnitude of the risk adjustment resulting from the actual electricity rate design changes to greater fixed rate recovery and the proposed changes of Enbridge Gas. Would the change in the proportion of distribution revenues recovered from fixed rates as compared to variable rates provide any insight as to the change in risk?

Response: Note that this interrogatory response has been prepared by LEI.

Fixed charges provide greater revenue certainty because the charges typically remain fixed for about a year, irrespective of the actual electricity usage. Greater revenue certainty reduces risk. Notably, the OEB also made similar conclusions in EB-2012-0410 (report dated April 2nd, 2015): *"Currently, a distributor's revenues vary depending on conservation, weather and economic activity. However, these factors have very little influence (in the short-term) on the costs a distributor pays. Under a fixed monthly charge, distributor revenues will be more stable and more predictable."*

TAB 20

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-4-VECC-22

Interrogatory

Reference:

Exhibit M1, page 77

Preamble:

At page 77, LEI states:

“Some regulators will exclude short-term debt with the view that it is temporary and will eventually be replaced with long-term capital.”

Question:

Why is the above noted methodology that is used by some regulators not superior or at least equivalent to the Board’s policy of providing a short-term debt component and associated cost rate in its deemed capital structure?

Response: Note that this interrogatory response has been prepared by LEI.

There is potential to observe variation between short-term and long-term rates. For example, the OEB approved DSTDR as 6.23% and DLTDR as 4.58% in October 2023. Distinguishing between long-term and short-term debt rates will likely result in more cost-reflective estimates.

TAB 21

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-12-VECC-49

Interrogatory

Reference:

Exhibit M1, page 138, Figure 50

Preamble:

At page 138, Figure 50 shows:

Figure 50. Deemed capital structure allowed to electricity distributors in Ontario from 1999 to 2006

Rate base	Deemed capital structure		Deemed debt rate
	Debt	Equity	
> $1.0 billion	65%	35%	5.8%
$250 million - $1.0 billion	60%	40%	5.9%
$100 million - $250 million	55%	45%	6.0%
< $100 million	50%	50%	6.25%

Source: OEB. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20th, 2006. Page 4.

Question(s):

a) Does LEI agree that a utility's rate base or customer size could affect business or financial risk?

b) Does LEI believe that utility size (by number of customers or rate base) may affect a utility's cost of debt?

c) If an electricity or natural gas distributor is heavily reliant upon a very small number of large customers (as may occur in rural towns) how should this be addressed in either the setting of equity returns or capital structure (or at all)?

d) LEI notes that the Board moved away from variation of capital structure for electric distributors in order to encourage (or at least not discourage) utility consolidation. Why is this not a violation of the principle articulated by LEI that utility ownership should not influence cost of capital determination?

e) Why is it not a violation of the fair return standard if the regulator acknowledges a difference in risk among utilities but then ignores that difference in order to achieve a different policy outcome?

f) What jurisdiction and legislative authority does the Ontario Energy Board rely upon which would allow it to prioritize utility consolidation over the fair return standard?

g) The Board regulates a small gas utility (EPCOR). Given the Board's stated policy on consolidation was generally in respect to electricity distributors should the OEB consider varying capital structure adjustment for small gas utilities?

Response: Note that this interrogatory response has been prepared by LEI.

a) LEI has explored these questions in detail in Section 4.12.4 and Section 4.13.4 of the LEI Report.

b) Please see the response in a) above.

c) Please see the response in a) above.

d) LEI understands that the OEB recommendations for consolidation are uniformly applicable for utilities of all ownership structures.

e) LEI does not believe encouraging utility consolidation violates the FRS. All Ontario utilities retain the option to pursue consolidation if size is a constraint.

f) Please see LEI response in e) above.

g) The OEB may consider the suggested implications if there is an equity thickness application by EPCOR or other participants.

3. **Grouping electricity distributors based on their risk profile** (similar to the OEB approach prior from 1999 to 2006), considering size (customers or rate base) as a proxy for risk, i.e., smaller size implies higher risk and vice versa.

4.12.4 Recommendations

LEI believes the OEB's status quo approach, with one modification, is sound, administratively efficient, and meets the FRS.[362] Alternative #2 (setting capital structure using rating agency benchmarks) has merits, but the benefits from changing the status quo approach are not material. However, the OEB should mandate forward-looking cash flow analysis with scenarios for utilities (or participants) within the status quo approach (as part of financial risk analysis) when requesting a change in equity thickness.[363]

The OEB's 1999 decision in proceeding RP-1999-0034 established a size-based capital structure for electricity distributors (with rate base as proxy for size).[364] The deemed capital structure allowed to distributors from 1999 to 2006 is shown in Figure 50 below.

Figure 50. Deemed capital structure allowed to electricity distributors in Ontario from 1999 to 2006

Rate base	Deemed capital structure		Deemed debt rate
	Debt	Equity	
> $1.0 billion	65%	35%	5.8%
$250 million - $1.0 billion	60%	40%	5.9%
$100 million - $250 million	55%	45%	6.0%
< $100 million	50%	50%	6.25%

Source: OEB. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20th, 2006. Page 4.

In 2006, the OEB moved away from this approach to a single capital structure for all distributors to avoid creating barriers to consolidation by incentivizing smaller size ***(emphasis added)***:[365]

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[362] The ROE (in absolute dollar terms) earned by a regulated equity is a function of deemed equity in the approved rate base and the allowed ROE (%). Either can be altered in response to changes in perceived risks to the utility and meet the FRS. As the same outcome can be obtained by adjusting one or the other of the levers, LEI did not consider switching to a uniform capital structure and varying ROEs.

[363] For example, in its expert report regarding the appropriate equity thickness for Enbridge Gas (EB-2022-0200 - Exhibit M - Staff Cost of Capital), LEI stress-tested equity ratios of 36%, 37% and 38% (with ROEs of 8.36%, 7.36%, and 6.36%, i.e., nine scenarios in total) for tail risk scenarios. LEI projected cash flows for the 2024-2028 IRM period to assess how the key credit metrics considered by rating agencies would be affected in each scenario.

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

[365] Ibid. Page 6.

"While there were over 300 distributors in 1998, there are now less than 90. While there are some very small distributors in existence, the trend has been toward fewer and larger distributors. A recent Government announcement of a new two-year transfer tax exemption may spur further consolidation. ***This trend underscores the need to ensure that the Board does not create barriers to consolidation. In the Board's view, one of those barriers is the differing capital structure of distributors****."*

The OEB also noted that one quarter of the small distributors have leveraged themselves with debt to levels in excess of 50%, adding that a distributor, *regardless of size, when planning and making decisions to manage its business risk, will organize its financing in line with its business needs*.[366] Furthermore, the OEB considered the higher equity thickness for smaller distributors to be unfair to the customers served by those distributors as *there is no basis upon which ratepayers should be required to bear different costs, associated with different capital structures, on the basis of distributor size*.[367]

The reasoning provided by the OEB in 2006 still applies to electricity distributors. The OEB has also consistently encouraged consolidations and has accordingly published clear guidelines to file applications for mergers, acquisitions, amalgamations and divestitures ("MAADs").[368] Allowing higher equity thickness (and thus higher cost of capital in dollar terms) will reward the utilities for remaining small. LEI acknowledges that there are other barriers to consolidation (summarized in the text box below) that are outside the scope of this Generic Proceeding.[369]

Barriers to utility consolidation (outside the scope of Generic Proceeding)

Local distribution companies may face barriers to capital raising which cannot be resolved through the cost of capital proceeding. For example, some shareholders may face challenges balancing the need to mobilize capital through equity injections or retained earnings against the desire to maintain payout ratios. However, an individual shareholder's desire to maintain a specific level of cash flows through dividend payouts has no bearing on the determination of the cost of capital itself. Furthermore, while the transfer tax changes the economics of raising equity for municipally-owned LDCs, it has no bearing on the volatility of the underlying cash flows to equity.

As such, LEI recommends that the status quo approach be continued. Consistent with the principles outlined by LEI in Section 3.1, there is no material benefit from transitioning to Alternative #2 (uniform capital structure while adjusting the ROE) or Alternative #3 (size-based capital structure with size as a proxy for risk).

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[366] Ibid. Page 7.

[367] Ibid. Page 7.

[368] OEB. Handbook to Electricity Distributor and Transmitter Consolidations. January 19th, 2016.

[369] According to the Ontario Ministry of Finance website (Ontario.ca/page/transfer-tax), a transfer tax exemption is in place until December 31st, 2024. The transfer tax upon a sale of municipally owned electricity assets to the private sector is reduced from 33% to 22% of the fair market value at the time of sale, with a further deduction for previous payments in lieu ("PIL") of taxes. Utilities with fewer than 30,000 customers are fully exempt.

Section 4.2.3) is inefficient and unnecessary. LEI recommends that the OEB's current policy (reviewing business/financial risk factors if there is a significant change from the status quo) be retained. Furthermore, LEI believes that adjusting the allowed /deemed equity thickness remains the appropriate lever to address material changes in the utility risk profile. The utility (or participants) may request a change in equity thickness in the rebasing application. If there is an application to review the change in risks by the utility or the intervenors, LEI recommends that the OEB review the change in business risks (volumetric risk, operational risk, regulatory risk and policy risk including energy transition risk) and financial risks (whether there is a change in the ability of the utility to continue to attract debt and equity financing at reasonable terms). However, this should not preclude the utilities from highlighting additional risk categories in their rate applications if they consider them to be material in nature.

LEI's recommendation to retain the status quo is consistent with the principles outlined by LEI in Section 3.1 as it meets the FRS by factoring the risk factors that may materially impact future utility cash flows, it is simple to administer as a complete review of business/financial risks is required only when the change in risk profile is perceived to be significant, and provides confidence to all stakeholders regarding the durability of the methodology by continuing with the status quo.

LEI recommendations - Issue 2

- The risk factors considered in recent equity thickness proceedings are sufficient.
  - Business risk assessment can be performed based on changes in volumetric risk, operational risk, regulatory risk and policy risk (including energy transition risk).
  - The assessment of financial risks can focus on the utility's ability to continue attracting debt and equity financing at reasonable terms, primarily relying on assessing key credit metrics and their potential impact on credit ratings.
- The current policy of considering the impact of risk factors when there is a significant change in business/financial risks is a reasonable approach, which LEI recommends be retained.

4.3 General issues – key regulatory and rate-setting mechanisms impacting utility risk

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

In the preceding section, as part of the business risk assessment, LEI classified ***regulatory risks,*** i.e., potential impacts of the regulator's policies and decisions on the utility's cash flows. LEI recommended that the OEB retain its existing policy of reviewing business/financial risks (which includes regulatory risks) if there is a significant change or upon application by the utility or the intervenors.

In this section, LEI has reviewed the impacts of some of the key OEB policies and decisions associated with regulatory and rate-setting mechanisms enacted since 2006. In addition, LEI has

TAB 22

Ontario Energy Board

Report of the Board

on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors

December 20, 2006

2.1 Capital structure

Policy and Rationale

The Board will deem a single capital structure for all distributors for rate-making purposes. The Board has considered the concerns that have been expressed by distributors and certain members of the investment community that a reduction in equity thickness or return might result in a lower credit rating. As discussed below, the Board is not convinced these concerns warrant differentiated deemed capital structures. Therefore, **the Board has determined that a split of 60% debt, 40% equity is appropriate for all distributors.**

To date, the Board has used four size-related deemed capital structures for rate regulation of electricity distributors. As noted previously, this was based on the study conducted by Dr. Cannon for the development of the first Distribution Rate Handbook. In his study, Dr. Cannon noted that:

> Conceptually, [distributor] deemed capital structure ratios for rate-regulation purposes and/or their allowed returns on equity should vary to reflect the extent of the business risks to which each MEU is exposed. Higher relative business risks will imply less debt-carrying capacity and hence call for higher deemed common equity ratios (CERs). Furthermore, if the higher CER does not fully compensate for a MEU's relatively higher business risk, then the allowed return on equity (ROE) should also be adjusted upward to compensate MEU owners for the relatively higher total investment risk that their ownership stakes are exposed to.

However, Dr. Cannon recognized that it was not practical to review the capital structure for each distributor. He concluded that it was appropriate to stratify distributors into a limited number of groupings of similar risk. Further, he identified a number of characteristics that, in his view, affected the risk profile of a distributor:

(1) The size of the distributor's operations, assets, and revenue base;
(2) The nature and stability of the distributor's customer mix;
(3) Degree of competition from other fuels;

(4) The age and condition of the physical distribution system;
(5) Local climate peculiarities;
(6) The geographic size and isolation of the distributor's service area; and
(7) The availability of back-up self-generation capacity.

However, in his final analysis, Dr. Cannon settled on factors (1) and (6). Other criteria were rejected on the basis that the influence of each factor was generally small and/or “diversifiable”. Factors (1) and (6) were assessed to be recognizably correlated with each other, and, as a result, risk categorization based on size was believed to be warranted in 1998.

The electricity distribution sector has undergone significant change over the last eight years, and that change supports the move from size-related capital structures to a common capital structure. In particular, there has been considerable restructuring through mergers and acquisitions. While there were over 300 distributors in 1998, there are now less than 90. While there are some very small distributors in existence, the trend has been toward fewer and larger distributors. A recent Government announcement of a new two-year transfer tax exemption may spur further consolidation. This trend underscores the need to ensure that the Board does not create barriers to consolidation. In the Board’s view, one of those barriers is the differing capital structure of distributors.

Larger distributors generally supported the 60:40 structure as it means little or no change for them. However, smaller distributors expressed a number of concerns and disagreed with the proposal of a single capital structure.

Many distributors commented that size was an important measure of risk that must continue to be reflected in the cost of capital. Comments were made that small distributors face greater business risk than large distributors when a significant fraction of their load is from a single customer or when there is load concentration in a limited number of sectors (e.g. forestry, agriculture, etc.). According to this view, for a small distributor, a downturn in the sector may also result in consumers and local businesses (restaurants, stores, etc.) moving away, while larger distributors may operate in more diversified local economies and hence be better protected from a sector downturn.

The Board notes that load concentration risk, which was the primary focus of distributor concerns, is not necessarily related to distributor size. Horizon Utilities, Oakville Hydro and EnWin Powerlines are examples of mid-sized distributors with concentrated loads. As discussed previously, the four size-based categories have been in effect since industry restructuring and distribution rate unbundling. Based on changes to the sector over the last eight years and data from distributors' operations since 1999 the Board concludes that size is not a key determinant of, or proxy for, risk.

This conclusion is corroborated by the Board's examination of 2005 financial data filed by electricity distributors, which show that the distributors exhibit a variety of actual debt-equity structures. According to the data, about one quarter of the small distributors have leveraged themselves with debt to levels in excess of 50%. These distributors do not appear to be experiencing particular financing concerns as a result of this debt load.

A distributor, regardless of size, when planning and making decisions to manage its business risk, will organize its financing in line with its business needs.

The Board concludes that utility size no longer represents an accurate proxy for risk. As a result, there is no basis upon which ratepayers should be required to bear different costs, associated with different capital structures, on the basis of distributor size. The question the Board must ask is whether ratepayers of smaller distributors should pay higher rates than those of larger distributors because of a thicker equity component. For these reasons it is the Board's view, that for ratemaking purposes, a single capital structure for all distributors is appropriate.

To avoid the unintended consequences of transition causing gross mismatch between actual and deemed capital structure, the Board has determined that a staged implementation will be used. This is discussed in sub-section 4.1, below. In addition, if the change in capital structure, and the increase in debt, leads to higher costs for new third-party debt, those higher costs will be reflected in rates. This is explained further in section 2.2.1.

The Board does recognize that some distributors may face materially different risks for the reasons identified by Dr. Cannon. However, it is incumbent upon the distributor to provide evidence of those risks. Whether the Board might address these risks through a different capital structure or a variance in the equity risk premium would depend on its consideration of the evidence provided. Distributors that believe they are in this category may raise this issue at rebasing. Distributors should also review the Board's letter of December 19, 2006 which deals with the timing of rebasing. Attached to that letter is a discussion paper on a screening methodology to establish a rebasing schedule for electricity distributors, including the option of self nomination.

Issues and Options Raised in Consultation

Most consumer groups support the single capital structure. During the technical conference, one stakeholder acknowledged that "small cap" firms do normally attract a risk premium in the market, but stated that information asymmetry is a major reason for this. This stakeholder further commented that information asymmetry occurs when an investor knows less about a small firm than would be the case with a large firm. However, in this context, information asymmetries are immaterial for regulated firms as they all report the same data to the regulator routinely, and publicly.

Some stakeholders expressed concern that during the transition to the new deemed structure distributors will restructure and take on more debt, possibly violating existing debt covenants or risking credit rating downgrades. However, the Board notes that a distributor's actual structure does not have to be the same as its deemed capital structure.

TAB 22