Independent expert report for the Generic Proceeding on cost of capital and other matters (EB-2024-0063)

prepared for the Ontario Energy Board ("OEB" or "the Board") by London Economics International LLC ("LEI")

June 21st, 2024

LEI was engaged by OEB Staff to assist their participation in the generic proceeding on cost of capital and other matters (referred to as "Generic Proceeding" or "EB-2024-0063"), and file evidence, testify and provide an independent analysis of the relevant matters pertaining to utilities and the Ontario energy sector.

In this report, LEI was asked to review the 22 issues (primarily related to matters associated with cost of capital) identified in the OEB's Final Issues List for the Generic Proceeding. LEI has evaluated precedents, practices followed in North American and global jurisdictions, current landscape, and potential alternatives, and made recommendations based on the following principles: (i) meeting the Fair Return Standard ("FRS"); (ii) simple to administer relative to the status quo; (iii) transition from status quo only if the benefits of transition are material; (iv) fairness in approach to consumers and utilities; and (v) predictability and transparency.

Overall, LEI proposes evolutionary rather than revolutionary changes in response to the issues identified in the Generic Proceeding. LEI has recommended that several aspects of the status quo (such as adjusting the deemed capital structure only when there is a significant change in risk profile, not considering the ownership structure of the utilities in the cost of capital determination, and the updating frequency of key cost of capital parameters) be retained. However, the findings suggest that Ontario utilities and consumers may benefit from modifications to the current approaches, such as determining base return on equity ("ROE"), debt interest rates, and carrying charges allowed for the cloud computing deferral account.

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List of acronyms

ACM	Dutch Authority for Consumers and Markets
AER	Australian Energy Regulator
AGO	Auditor General of Ontario
Apex	Apex Utilities Inc.
AUC	Alberta Utilities Commission
BA	Bankers' Acceptance
BC	British Columbia
BC Hydro	British Columbia Hydro and Power Authority
BCA	Benefit-cost analysis
BCUC	British Columbia Utilities Commission
BoC	Bank of Canada
BRA	Business risk assessment
bps	Basis points
CAPM	Capital asset pricing model
capex	Capital expenditure
CARR	Canadian Alternative Reference Rate
CCM	Cost of Capital Mechanism
CCR	Capital cost recovery
CDOR	Canadian Dollar Offered Rate
CE	Comparable Earnings
CER	Canada Energy Regulator
CFIF	Canadian Fixed-Income Forum
CFO	Cashflow from Operations
CGS	Commonwealth Government Securities
COA	1-month Canadian Overnight Repo Rate Average future
Con Edison	Consolidated Edison Company of New York, Inc.
Concentric	Concentric Energy Advisors
CORRA	Canadian Overnight Repo Rate Average
COS	Cost-of-service
CPI	Consumer Price Index
CPIH	Consumer Price Index including owner occupiers' housing costs
CPUC	California Public Utilities Commission

CRA	3-month Canadian Overnight Repo Rate Average future
CWIP	Construction work in progress
DBRS	DBRS Morningstar
DCF	Discounted cash flow
DGM	Dividend growth model
DLTDR	Deemed long-term debt rate
DSTDR	Deemed short-term debt rate
DVAs	Deferral and variance accounts
EBIT	Earnings before Interest and Taxes
EBITDA	Earnings before Interest, Taxes, Depreciation and Amortization
ED	Electric distribution
EICSI	Energy Infrastructure Credit Spread Index
Enbridge Gas	Enbridge Gas Inc.
ENMAX	ENMAX Energy Corporation
ENWL	Electricity North West Limited
EPCOR Natural Gas	EPCOR Natural Gas Limited Partnership
EPS	Earnings per share
ERP	Equity risk premium
ESG	Environmental, social, and governance
FBC	FortisBC Inc.
Fed	Federal Reserve
FEI	FortisBC Energy Inc.
FFO	Funds from Operations
Foster	Foster Associates Inc.
FRA	Financial risk assessment
FRS	Fair Return Standards
FTSE mid-term index	FTSE Canada Mid Term Bond Index All Corporate yield
GCOC	Generic cost of capital
GD	Gas distribution
GoC	Government of Canada
GOCA	Getting Ontario Connected Act
GRA	General Rate Application

HER	Historical excess return
Hydro One	Hydro One Networks Inc.
IAs	Impact assessments
ICM	Incremental Capital Module
IR	Incentive rate-setting
IRAC	Price Edward Island Regulatory and Appeals Commission
IRM	Incentive rate-setting mechanism
IRs	Information requests
LCBF	Long Canada Bond Forecast
LEAP EFA	Low-income Energy Assistance Program Emergency Financial Assistance
LEI	London Economics International LLC
LIBOR	London Interbank Offered Rate
MAADs	Mergers, acquisitions, amalgamations and divestitures
MECL	Maritime Electric Company Limited
Moody's	Moody's Investors Service
MRP	Market risk premium
NARUC	National Association of Regulatory Utility Commissioners
NEB	National Energy Board
NEO	National Electricity Objective
NGO	National Gas Objective
NGR	National Gas Rules
NGTL	NOVA Gas Transmission Limited
NPVs	Net present values
NSPI	Nova Scotia Power Inc.
NSPs	Network Service Providers
NWAs	Non-wires alternatives
NY	New York
NYSEG	New York State Electric & Gas Corporation
OBR	Office of Budget Responsibility
OCR	Operating cost recovery
OEB	Ontario Energy Board
OEB Act	Ontario Energy Board Act
OECD	Organisation for Economic Co-operation and Development

Ofgem	Office of Gas and Electricity Markets
OM&A	Operations, maintenance, and administration
OPG	Ontario Power Generation Inc.
PBR	Performance-based ratemaking
PG&E	Pacific Gas & Electric Company
RAB	Regulated Asset Base
RAM	Return Adjustment Mechanisms
RAV	Regulatory Asset Value
RBA	Reserve Bank of Australia
REV	Reforming the Energy Vision
RG&E	Rochester Gas & Electric Corporation
RIIO	Revenues = Incentives + Innovation + Outcomes
RIIO1	First price control period under the Revenues = Incentives + Innovation + Outcomes framework
RIIO2	Second price control period under the Revenues = Incentives + Innovation + Outcomes framework
RIIO-ED1	First price control final determinations for electric distribution companies under the Revenues = Incentives + Innovation + Outcomes framework
RIIO-ED2	Second price control final determinations for electric distribution companies under the Revenues = Incentives + Innovation + Outcomes framework
ROE	Return on equity
RPI	Retail Prices Index
RRA	Revenue Requirement Application
RRFE	Renewed regulatory framework for electricity
S&P Global	S&P Global Ratings
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SL CAPM	Sharpe-Lintner capital asset pricing model
SFVD	Straight fixed variable with demand
SoCalGas	Southern California Gas Company
SOFR	Secured Overnight Financing Rate
SSSC	Standard Supply Service Code
Tx	Transmission
The Board	Ontario Energy Board
TMR	Total market returns

TMX	Montreal Exchange
TransCanada	TransCanada PipeLines Ltd.
UK	The United Kingdom
USAID	United States Agency for International Development
UsoA	Uniform System of Accounts
WACC	Weighted average cost of capital

1 Executive summary

LEI was retained by OEB Staff as an independent expert to address the questions identified in the OEB's Final Issues List for the Generic Proceeding. This report also includes a jurisdictional review, highlighting approaches unique or relevant to the Ontario context, and provides indicative recommendations associated with relevant issues/questions.

The OEB has identified 22 issues in this Generic Proceeding associated with methodologies for calculating the cost of capital parameters (ROE and deemed long-term/short-term debt rates), deemed capital structure, prescribed interest rates for deferral/variance accounts, and additional interest rate/ carrying charge, if any, that should apply to the generic cloud computing deferral account.

LEI has devised five overarching principles to evaluate its potential alternatives (derived from OEB's mission and mandate, and its existing principles related to cost of capital and accounting) and arrived at its recommended approach. The principles are as follows:

1. ***Meeting the FRS***, which is a legal requirement;
2. ***Simple to administer relative to the status quo***, i.e., the costs (if any) of transitioning away from the status quo and administering the recommended alternative are reasonable;
3. ***Transitioning away from the status quo only if the associated benefits are material*** as there is limited merit in modifying aspects of the methodology that have worked well;
4. ***Fairness in approach to consumers and utilities***, consistent with the OEB's mission and mandate, to ensure efficient investments; and
5. ***Predictability and transparency*** in the recommended approach to ensure that the outcomes from the proposed methodology are relatively stable over a long-term time horizon.

Overall, LEI proposes evolutionary rather than revolutionary changes in response to the issues identified in the Generic Proceeding. The table below summarizes the issues identified by the OEB, the OEB's current practice, and LEI's recommendations.

Issue #	Issue	Status quo	LEI recommendation
	A. General issues		
1	Should the approach to setting cost of capital parameters and capital structure differ depending on: a) The source of the capital (i.e., whether a utility finances its business through the capital markets or through government lending such as Infrastructure Ontario, municipal debt, etc.)? b) The different types of ownership (e.g., municipal, private, public, co-operative, not for profit, Indigenous / utility partnership, etc.)?	The OEB considers different funding sources (by considering actual debt interest rates in most cases) but does not consider the ownership structure	• The OEB's existing methodology implicitly accounts for differences in sources of funding when approving rate applications. LEI recommends that this aspect of the OEB methodology be retained. • Consistent with the OEB's existing policy, the approach to setting the cost of capital parameters and capital structure should not depend on a utility's ownership structure. LEI believes the status quo is consistent with the FRS and Canadian Supreme Court judgement(s).
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?	• The recent risk assessments have considered business risks (energy transition risk, volumetric risk, operational risk, regulatory risk, and policy risk) and financial risk • The OEB undertakes a full reassessment of a utility's capital structure in the event of significant changes in risks	• The risk factors considered in recent equity thickness proceedings are sufficient. o Business risk assessment can be performed based on changes in volumetric risk, operational risk, regulatory risk and policy risk (including energy transition risk). o The assessment of financial risks can focus on the utility's ability to continue attracting debt and equity financing at reasonable terms, primarily relying on assessing key credit metrics and their potential impact on credit ratings. • The current policy of considering the impact of risk factors when there is a significant change in business/financial risks is a reasonable approach and is recommended to be retained.

Issue #	Issue	Status quo	LEI recommendation
3	What regulatory and rate-setting mechanisms impact utility risk, and how should these impacts be considered in determining the cost of capital parameters and capital structure?	• LEI reviewed five major OEB policy initiatives since 2006 • The OEB considers regulatory risks during risk assessments associated with equity thickness proceedings	• Any regulatory mechanism that can significantly impact the stability of future cash flows must be considered for review as part of regulatory risks • The five major OEB policy initiatives since 2006 reviewed by LEI have slightly reduced the risks for electricity distributors • The current policy of considering the impact of risk factors on request when there is a significant change in business/financial risks (including regulatory risk) is a reasonable approach, which LEI recommends be retained • In addition, LEI recommends proactive impact assessments ("IAs") before material regulatory changes
	B. Short-term debt rate		
4	Should the short-term debt rate for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be set using the same approach as set out in the OEB Report?[1]	• For electricity distributors and transmitters, DSTDR is used to set short-term debt rates, using a formulaic approach • For natural gas distributors and OPG, short-term debt rates are based on their actual debt portfolio	The current DSTDR methodology (3-month BA rate plus a spread) is no longer appropriate as major Canadian banks will transition all existing financial products that reference CDOR/BAs to referencing Canadian Overnight Repo Rate Average ("CORRA") on or before June 28th, 2024
5	If no to Issue #4, how should the short-term debt rate be set?	N/A	• For reference rate, the average of 3-month CORRA futures rates be considered for the next 12-month period • The spread for a R1-low rated utility over CORRA be determined from an annual confidential survey of banks (slightly modified from the status quo vis-à-vis larger sample size of 6-10 banks and limited exclusion of outliers) • DSTDR be applied as a cap for all utilities
	C. Long-term debt rate		

[1] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (OEB Report), December 11, 2009, pp. iii, 55-59

Issue #	Issue	Status quo	LEI recommendation
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?[2]	• For natural gas distributors and OPG, the long-term debt rates are considered based on the weighted cost of actual embedded debts • For electricity distributors and electricity transmitters, long-term debt rates primarily rely on embedded or actual cost for existing long-term debt instruments, albeit with the DLTDR calculated using a formulaic approach, acting as a proxy or a ceiling	The current methodology is broadly appropriate but can be improved upon (see below)
7	If no to Issue #6, how should the long-term debt rate be set?	N/A	• Reputable publicly available sources for 30-year bond yield forecasts for LCBF/risk-free rate be considered • Bloomberg's BVCAUA30 BVLI Index (12-month trailing average) is appropriate for considering the spread over LCBF for an A-rated utility • DLTDR applied as a cap for all utilities
8	How should transaction costs incurred by utilities be considered when setting the long-term debt rate?	The utilities typically record the transaction costs as interest expense, amortizing them using the effective interest rate method over the term of the related debt instrument	Transaction costs should be considered as operating expenses, as this approach is more suitable for the nature of the expense, which may fluctuate from year to year

[2] OEB Report, pp. 50-55, 59; EB-2009-0084, OEB Staff Report, Review of the Cost of Capital for Ontario's Regulated Utilities (Staff Report), January 14, 2016, p. 3 Table 1

<table>
<tr><th>Issue #</th><th>Issue</th><th>Status quo</th><th>LEI recommendation</th></tr>
<tr><td>9</td><td>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?</td><td>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</td><td>The status-quo approach (considering deemed capital structure regardless of the actual capital structure) is retained</td></tr>
<tr><td></td><td colspan="3">D. Return on equity</td></tr>
<tr><td>10</td><td>What methodology should the OEB use to produce a return on equity that satisfies the Fair Return Standard (FRS)?</td><td>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</td><td>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)</td></tr>
<tr><td>11</td><td>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?</td><td>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</td><td>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.</td></tr>
<tr><td></td><td colspan="3">E. Capital structure</td></tr>
</table>

Issue #	Issue	Status quo	LEI recommendation
12	How should the capital structure be set for electricity transmitters, electricity distributors, natural gas utilities, and OPG to reflect the FRS?	The OEB sets a uniform ROE for all regulated entities and adjusts the equity thickness in the capital structure based on business and financial risk assessment relative to the previous assessment	• The OEB's current approach of revising the capital structure upon application if warranted due to increase in business/financial risks is a reasonable practice, as OEB has noted that risks rarely change meaningfully in a short period of time • LEI believes that the existing approach meets the FRS • Applicants should be required to include forward cash flow modeling and scenario analysis showing impact on credit metrics to support their case
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?	While the capital structure for transmitters is determined on a case by case basis, the OEB has allowed a 40% equity thickness to all electricity transmitters since 2006 (same as electricity distributors)	• The current approach of allowing the same equity thickness to all electricity transmitters (and distributors) should be maintained
	F. Mechanics of implementation		
14	What on-going monitoring indicators to test the reasonableness of the results generated by its cost of capital methodology should the OEB consider, including the monitoring of market conditions?	The OEB conducts an ongoing monitoring process through quarterly reports for internal review purposes only	• Consistent with the OEB's existing policy, OEB staff should continue to monitor the cost of capital parameters and test their reasonableness in the context of prevailing macroeconomic conditions on a quarterly basis, through reports prepared for internal review purposes only
15	How should the OEB regularly confirm that the FRS continues to be met and that rate-regulated entities are financially viable and have the opportunity to earn a fair, but not excessive, return?	The OEB regularly confirms that the FRS is being met in its annual cost of capital update letters	• The OEB should continue to annually confirm that the FRS is being met, as it currently does through its cost of capital update letters • In addition, the OEB should direct utilities, as part of the annual reporting requirements, to provide credit ratings and details regarding new short-term and long-term debt and equity issued/borrowed during the year • The OEB may use this information to monitor the credit ratings and pace of capital injections for the regulated utilities on an ongoing basis, as a further test of whether the FRS continues to be met

Issue #	Issue	Status quo	LEI recommendation
16	What should be the timing of the OEB's annual cost of capital parameters updates, including the timing, as required, of the underlying calculations?	• The OEB updates the cost of capital parameters every year and publishes a letter with the updated parameters in October or November for rates taking effect in January or May of the following year • The underlying calculations typically rely on data as of the end of September	Consistent with the OEB's existing policy, the OEB should continue to publish its annual cost of capital parameter updates in October or November, using 12-month trailing data as of the end of September (i.e., from October of the previous year to September of the current year), for rates going into effect in the following January or May
17	What should be the defined interval (for example, every three to five years) to review the cost of capital policy (including, but not limited to, a review of the ROE formula and the capital structure)? Should the OEB adopt trigger mechanism(s) for a review and if so, what would be the mechanisms?	• The OEB is to review the cost of capital policy every five years, as stated in the OEB's cost of capital report issued in 2009 • An applicant or intervenors can file evidence in individual rate hearings if they believe the cost of capital parameters are not reasonable • Utilities under Price Cap IR or Annual IR Index rate-setting plans have an off-ramp mechanism	• Consistent with the OEB's existing policy, the OEB should commit to reviewing the cost of capital policy every five years • The OEB should also maintain the existing trigger mechanisms, including allowing utilities to apply for different cost of capital parameters during their individual rate hearings, as well as triggering a regulatory review through the off-ramp mechanism (which may or may not include a review of the cost of capital parameters) and/or capital structure • In the event that a regulatory review is triggered, the utility and/or intervenors should be allowed to submit evidence for the OEB's consideration regarding the extent to which the cost of capital parameters and/or capital structure caused or contributed to triggering the off-ramp. The OEB can then exercise its own judgement (based on the evidence presented) as to whether the cost of capital parameters and/or capital structure are to be included in the regulatory review
18	How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?	Changes in cost of capital parameters and capital structure are implemented once a utility files its cost of service application	Consistent with the OEB's existing policy, the OEB should continue to implement changes in the cost of capital parameters and capital structure upon rebasing

Issue #	Issue	Status quo	LEI recommendation
19	Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?	Utilities only transition to the new cost of capital parameters and capital structure once they file their cost of service application, not in the middle of an approved rate term	• Consistent with the OEB's existing policy, the OEB should continue to implement changes in the cost of capital parameters and capital structure upon rebasing • However, to ensure the FRS continues to be met, the OEB should also introduce an option for parties to request implementation of such changes prior to rebasing, so long as the two-factor test is met – (i) the utility should have more than 60% of its rate term remaining, and (ii) deviations in the cost of capital parameters should be material (100 bps or more)
	G. Other issues (prescribed interest rates)		
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?[3]	The OEB uses a formulaic approach to setting prescribed interest rates for DVAs and CWIP	• The current methodology for DVAs is no longer appropriate • The current methodology for CWIP should be retained

[3] 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

Issue #	Issue	Status quo	LEI recommendation
21	If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?	N/A	• For DVAs, LEI recommends aligning the prescribed interest rate with the revised calculation methodology recommended by LEI for the DSTDR – namely: o For the reference rate, LEI recommends considering the average of 3-month CORRA futures rates for the next 12-month period o The spread for a R1-low rated utility over CORRA should be determined via an annual confidential survey of banks (slightly modified from status quo vis-à-vis a larger sample size of 6-10 banks and no exclusion of outliers) • For CWIP, LEI recommends continuing the current approach of basing the prescribed interest rate on the FTSE Canada Mid Term Bond Index All Corporate yield for all construction projects, regardless of duration LEI also recommends continuing the current CWIP accounting procedures as set out in Article 220 (p. 200) and Article 410 (p. 27-28) of the OEB's *Accounting Procedures Handbook for Electricity Distributors*.
	G. Other issues (cloud computing deferral account)		
22	Should carrying charges and/or another type of rate apply to the Cloud Computing deferral account? If so, what rate should be applied?[4]	The OEB treats the cloud computing deferral account as a regular DVA account	• LEI believes a deemed WACC is necessary as a means of aligning incentives for utilities to transition to cloud computing solutions • LEI recommends that the OEB employ a deemed capital additions approach, which allows deemed WACC on the unamortized portions of the cloud computing contracts

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

2 Background and status quo

2.1 Procedural background

On March 6th, 2024, the OEB issued a Notice of Hearing on its own motion to initiate the Generic Proceeding (EB-2024-0063, hereinafter referred to as "Generic Proceeding"), to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used to set rates for electricity distributors, electricity transmitters, rate-regulated electricity generators and natural gas utilities.[5]

The Generic Proceeding will examine the current methodologies for calculating cost of capital parameters, deemed capital structure, prescribed interest rates, and additional interest rate/ carrying charge, if any, that should apply to the generic cloud computing deferral account.

In addition to the OEB's policy to review cost of capital parameters periodically, the impetus to this Generic Proceeding can be found in the recent Auditor General of Ontario's ("AGO's") *Value-for-Money Audit*, published in November 2022, and the OEB's *2023-2026 Business Plan* ("OEB Business Plan"). The AGO's relevant recommendations to the OEB are summarized in the text box below. The OEB's 2024-2027 Business Plan stated that the Generic Proceeding will fulfill the below recommendations from the AGO.[6]

Auditor General of Ontario's recommendations to the OEB

To regularly confirm that rate-regulated entities are financially viable and earn a fair, but not excessive, return, the Auditor General of Ontario recommended that the OEB:

- *review the deemed capital structure and return on equity ("ROE") formula and thereafter at defined intervals (for example, every three to five years); and*
- *adjust the deemed capital structure and ROE formula as informed by the review, so that they reflect the risk profile of rate-regulated entities.*

Source: Office of the Auditor General of Ontario. Value-for-money audit: Ontario Energy Board: Electricity oversight and consumer protection. November 2022. Page 41.

2.2 Regulated sector background

The OEB regulates Ontario's natural gas and electric utilities. The government of Ontario has set out its objectives and responsibilities in *the Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B ("OEB Act").[7] The OEB has regulated the natural gas sector since 1960 and the electricity sector since 1999.[8]

[5] OEB. EB-2024-0063. Notice of a rate hearing. March 6th, 2024.

[6] OEB. OEB Business Plan 2024-2027. April 4th, 2024.

[7] Government of Ontario. Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B. Accessed on June 3rd, 2024.

[8] OEB. Mission and mandate. Accessed on April 17th, 2024.

Electricity distribution: Ontario currently has 58 distributors which are rate-regulated by the OEB.[9] The electricity distributors serve approximately 5.5 million customers, 99% of whom are residential and small business customers.[10] The top five electricity distributors (in terms of load served) account for 78% of the total load served and 74% of total assets owned by all distributors.[11,12]

Electricity transmission: Ontario currently has eight transmitters in the electricity sector, which are regulated by the OEB.[13] Hydro One Networks Inc. ("Hydro One") is the largest electricity transmitter in Ontario, serving 35 local distribution companies and 85 large industrial customers (accounting for more than 90% of the regulated transmission asset base in Ontario).[14,15]

Rate-regulated electricity generation: Ontario Power Generation Inc. ("OPG") is the only electricity generator in the province that undergoes a public review of its rates by the OEB.[16] OPG's regulated asset base is made up of regulated hydroelectric and nuclear generation facilities. OPG's regulated hydroelectric and nuclear generation facilities account for ~34% of Ontario's total grid-connected generation capacity.[17,18]

Natural gas distribution: The OEB regulates two distributors in the natural gas sector: Enbridge Gas Inc. ("Enbridge Gas") and EPCOR Natural Gas Limited Partnership.[19] The two natural gas distributors serve approximately 3.9 million customers, 99.4% of whom are residential and small business customers.[20] Notably, Enbridge Gas served 3.8 million customers in 2022, accounting for 99.7% of all customers in Ontario.[21]

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[9] OEB. List of licensed companies. Updated on April 30th, 2024.

[10] OEB. Overview of energy sector. Accessed on May 1st, 2024.

[11] The top 5 electricity distributors by demand (metered kWh consumption) in 2022 were Hydro One Networks Inc., Alectra Utilities Corp., Toronto Hydro-Electric System Ltd., Hydro Ottawa Ltd., and Elexicon Energy Inc. Source: OEB. Electricity reporting & record keeping requirements (RRR): Section 2.1.7 trial balance. November 1st, 2023.

[12] OEB. Electricity reporting & record keeping requirements (RRR): Section 2.1.5.4 demand and revenue. October 6th, 2023.

[13] OEB. List of licensed companies. Updated on April 30th, 2024.

[14] Hydro One Networks Inc. Investor fact sheet – Third quarter 2023. 2023.

[15] In addition to Hydro One Networks Inc., the other seven OEB-regulated transmitters include: B2M Limited Partnership, Canadian Niagara Power Inc., Five Nations Energy Inc, Hydro One Sault Ste Marie Inc., Niagara Reinforcement Limited Partnership, Upper Canada Transmission 2, Inc., and Wataynikaneyap Power GP Inc.

[16] OPG. OEB applications. Accessed on June 3rd, 2024.

[17] OEB. EB-2020-0290. Overview of OPG. Filed: December 31st, 2020.

[18] Some OPG assets are not rate-regulated and operate under long-term contracts with IESO.

[19] OEB. List of licensed companies. Updated on April 30th, 2024.

[20] OEB. Overview of energy sector. Accessed on May 1st, 2024.

[21] OEB. Natural gas distributor yearbooks. General information. October 20th, 2023.

The subsections below discuss the scope of this report, summary of status quo and the timeline of key relevant events.

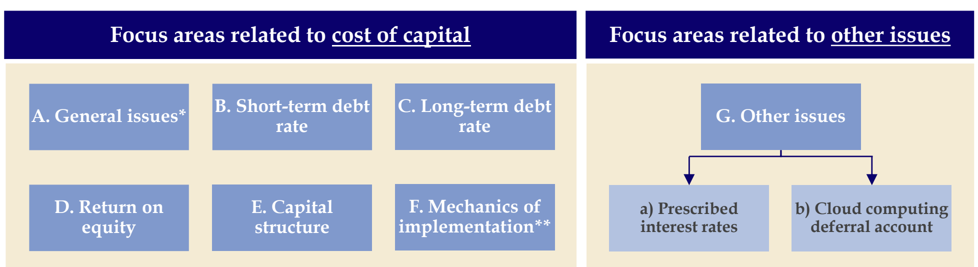
2.3 Scope of this report

LEI was retained by OEB Staff as an independent expert in the Generic Proceeding. LEI's scope is to *assist OEB staff in their participation in the Generic Proceeding, and file evidence, testify and provide an independent analysis of the relevant matters pertaining to utilities and the Ontario energy sector*.[22]

This report is LEI's independent evidence, which addresses the questions identified in the OEB's Final Issues List for the Generic Proceeding. This report also includes a jurisdictional review, highlighting approaches unique or relevant to the Ontario context, and provides indicative recommendations associated with relevant issues/questions.[23]

The Final Issues List is grouped into seven focus areas, as shown in Figure 1 below. Six focus areas relate to issues and questions regarding the cost of capital. The seventh focus area (i.e., *other issues)* relates to: (i) setting prescribed interest rates for deferral and variance accounts generally, and (ii) interest rate to be applied to cloud computing deferral account specifically.

Figure 1. Seven focus areas of the expert report



* **'General issues'** include questions on how (or if) factors such as the source of capital, types of ownership, and risk factors (including, but not limited to, the energy transition and changes in regulatory mechanisms) impact the cost of capital and capital structure.

** **'Mechanics of implementation'** mainly includes questions on adherence to Fair Return Standard ("FRS") and timing, review frequency/interval, and other considerations related to implementation of cost of capital methodology.

2.4 Brief background on LEI

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure since the late 1990s. Our experience along all aspects of the value chain of the power and gas sectors enables us to understand the interplay among the various components, a crucial skill needed for this project. LEI has over 25 years of experience in North American and international jurisdictions. With respect to Ontario, over the last two

[22] OEB. EB-2024-0063. Letter re: Generic Proceeding – cost of capital and other matters. OEB Staff's plan for expert evidence. March 28th, 2024.

[23] OEB. EB-2024-0063. Procedural Order No.1. March 28th, 2024.

decades, the firm (under the leadership of LEI President, Mr. AJ Goulding)[24] has completed numerous engagements with the OEB, local gas and electricity distribution companies, generators, market institutions, and a variety of other Ontario-based market players and stakeholders.

LEI staff have relevant experience in cost of capital and capital structure matters, reviewing regulatory dockets and supporting regulatory staff with filing interrogatories. A selection of relevant work is provided in "Appendix D: Selected relevant LEI experience", and further information is included in the curriculum vitae for Mr. Goulding, Mr. Pinjani, and Mr. Nayak (provided separately).

2.5 Summary of status quo

The OEB uses a formulaic methodology for determining the return on equity ("ROE"), deemed long-term debt rate ("DLTDR"), and the deemed short-term debt rate ("DSTDR"), which was initially approved in 2009.[25] The OEB examines the formula-generated results annually and aims to conduct periodic reviews on its formulaic approach every five years.

The prevailing methodologies for updating the key cost of capital parameters are shown in Figure 2.

[24] AJ Goulding is also an adjunct associate professor at Columbia University's School of International and Public Affairs and a faculty affiliate with the Columbia Center on Global Energy Policy ("CGEP"). Source: Center on Global Energy Policy.

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

Figure 2. Prevailing methodology for updating ROE, DLTDR and DSTDR

Parameter	Formula	Description	Value (2024)	Review frequency
ROE	ROE_t= Base ROE + LCBF adjustment factor x ($LCBF_t$ – Base LCBF) + UtilBondSpread adjustment fac x ($UtilBondSpread_t$ – Base UtilBondSpread)	• **Base ROE**: set at 9.75% in 2009; sum of Base LCBF and ERP of 550 bps, based on the average ERP submitted by participants • **LCBF adjustment factor**: set at 0.5 in 2009; the relationship between the allowed ROE and the LCBF; based on regression analysis performed by participants • **$LCBF_t$**: the average of the 3-month and 12-month 10-year GoC bond yield forecasts from Consensus Forecasts • **Base LCBF**: set at 4.25% in 2009 • **UtilBondSpread adjustment factor**: set at 0.5 in 2009, the relationship between the allowed ROE and the utility bond spread; based on regression analysis performed by participants • **$UtilBondSpread_t$**: the average spread of 30-year A-rated Canadian Utility bond yields over 30-year GoC bond yields over all business days in the month that is three months in advance of the implementation date for rates • **Base UtilBondSpread**: set at 1.415% in 2009	9.21%	Methodology is intended to be reviewed every five years; $LCBF_t$ and $UtilBondSpread_t$ updated annually
DLTDR	$DLTDR_t = LCBF_t + \frac{\sum_i ({}_{30}UtilBonds_{i,t} - {}_{30}CB_{i,t})}{I}$	• **$LCBF_t$**: the average of the 3-month and 12-month 10-year GoC bond yield forecasts from Consensus Forecasts • **${}_{30}UtilBonds_{i,t}$**: the average 30-year A-rated Canadian Utility bond yield rate, from Bloomberg for business day i of the month that is three months in advance of the implementation date for rates • **${}_{30}CB_{i,t}$**: the benchmark bond yield rate for the 30-year GoC bond at close of day I of the month that is three months in advance of the implementation date for rates • **I**: the number of business days of which GoC and A-rated Utility bond yield rates are published in the month that is three months before the implementation date for rates	4.58%	Methodology is intended to be reviewed every five years; all elements of the formula are updated annually
DSTDR	$DSTDR_t = AnnSpread_t + \frac{\sum_i BA_i}{I}$	• **$AnnSpread_t$**: the average annual spread in short-term issuances for an R1-low utility over 3- month Banker's Acceptance rates for the test year, calculated using a confidential survey • **BA_i**: the 3-month Bankers' Acceptance rate for day I in the selected month, as published by Statistics Canada and the BoC • **I**: the number of business days of which GoC and A-rated Utility bond yield rates are published in the month that is three months before the implementation date for rates	6.23%	

Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

2.5.1 Return on equity ("ROE")

The ROE is calculated using a base ROE of 9.75% (set in 2009) plus a Long Canada Bond Forecast ("LCBF") spread and a utility bond spread, subject to an adjustment factor of 0.5, as shown in Figure 3 below.

Figure 3. ROE formula

$$ROE_t = \text{Base ROE (9.75\%)} + 0.5 \times (LCBF_t - \text{Base LCBF}) + 0.5 \times (UtilBondSpread_t - BaseUtilBondSpread)$$

where:

- ROE_t = Return on Equity
- $LCBF_t$ = Long Canada Bond Forecast, calculated by taking the average of the 3-month and 12-month 10-year Government of Canada bond yield forecasts, as stated in the relevant issue of Consensus Forecasts.
- Base LCBF = 4.25%
- $UtilBondSpread_t$ = the average spread of 30-year A-rated Canadian Utility bond yields over 30-year Government of Canada bond yields over all business days in the month that is three months in advance of the implementation date for rates
- BaseUtilBondSpread = 1.415%

Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

The values for base ROE, base LCBF, and base utility bond spread were set in 2009 (EB-2009-0084). The OEB adjusts the ROE value annually by adjusting LCBF and utility bond spread based on current data.

The base ROE was determined as a sum of equity risk premium ("ERP") of 550 basis points ("bps") and base LCBF yield of 4.25%, based on the average ERP submitted by participants in EB-2009-0084.[26] The adjustment factors for the LCBF and the utility bond spread (both estimated to be 0.5) were determined based on the historical relationship between government bond yields and the ROE, and the relationship between corporate bond yields and the ROE, respectively.[27] The methodology used by the participants for the determination of adjustment factors is discussed later in Figure 31 and Figure 32.

The OEB utilizes the ROE for 40% of the capital structure for electricity distributors and transmitters.

2.5.2 Deemed long-term debt rate ("DLTDR")

The DLTDR determination primarily depends on the embedded or actual cost for existing long-term debt instruments.[28] The OEB sets the DLTDR for the test year equal to LCBF plus the average spread between a 30-year A-rated Canadian utility bond yield (derived from the Bloomberg utility series C29530Y) and the 30-year Government of Canada ("GoC") bond yield for all business days in the month, which is three months preceding the effective date for the rate changes. The formula is shown in Figure 4.

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[26] Ibid. Pages 37-38.

[27] Ibid.

[28] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

Figure 4. DLTDR formula

$$DLTDR_t = LCBF_t + \frac{\sum_i ({}_{30}UtilBonds_{i,t} - {}_{30}CB_{i,t})}{I}$$

where:

- $DLTDR_t$ = Deemed Long-Term Debt Rate
- $LCBF_t$ = Long Canada Bond Forecast
- ${}_{30}UtilBonds_{i,t}$ = the average 30-year A-Rated Canadian Utility bond yield rate, from Bloomberg L.P., for business day i of the month that is three months in advance of the implementation date for rates
- ${}_{30}CB_{i,t}$ = the benchmark bond yield rate for the 30-year Government of Canada bond at the close of day i of the month that is three months in advance of the implementation date for rates
- I = number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month that is three months in advance of the implemented date for rates

Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

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.[29]

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).[30,31]

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

2.5.3 Deemed short-term debt rate ("DSTDR")

To determine the DSTDR, the OEB obtains estimates of the spread of a typical short-term loan for an R1-low utility over the 3-month Bankers' Acceptance ("3-month BA") rate from major Canadian banks.[32,33] The formula is shown in Figure 5.

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29 OEB. OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

30 Ibid.

31 DLTDR can also be applied in other limited cases, which are described in Section 4.6.1.

32 The selection of R1-low is meant to reflect the credit status of most Ontario electric distributors, except for Toronto Hydro Electric Systems Limited and Hydro One Networks Inc., which had a credit status of R1-Mid or R1-High. However, the ratings for Toronto Hydro Electric Systems Limited and Hydro One Networks Inc. are currently R1-low and have remained so since at least 2013 and 2015 respectively. Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

33 Morningstar DBRS's rating scale for commercial paper and short-term debt is as follows (highest to lowest credit quality): R-1 (high), R-1 (middle), R-1 (low), R-2 (high), R-2 (middle), R-2 (low), R-3, R-4, and R-5 . Source: Morningstar DBRS. Product Guide. February 2024.

Figure 5. DSTDR formula

$$DSTDR_t = AnnSpread_t + \frac{\sum_i BA_i}{I}$$

where:

- $DSTDR_t$ = Deemed Short-Term Debt Rate
- $AnnSpread_t$ = the average annual spread in short-term debt issuances for an R1-low utility over 3-month Banker's Acceptance rates for the test year t, calculated using a confidential survey
- BA_i = the 3-month Bankers' Acceptance Rate for day i in the selected month, as published by Statistics Canada and the Bank of Canada
- I = number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month that is three months in advance of the implemented date for rates

Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

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.[34] 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.

The OEB utilizes the DSTDR for 4% of the capital structure for electricity distributors and transmitters.[35]

2.5.4 Deemed capital structure

The OEB's guidelines *assume that the base capital structure will remain relatively constant over time*, and requires undertaking a full reassessment of a utility's capital structure only in the event of significant changes in the company's business and/or financial risk.[36]

The OEB set the deemed capital structure at 60% debt and 40% equity for all electricity distributors and transmitters in 2006. In the 2009 report, the OEB stated that *capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy*.[37] As such, the OEB continued with a 60-40 debt-equity ratio for electricity distributors.

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[34] OEB. OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

[35] Ibid.

[36] OEB. EB-2009-0094. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009. Page 50.

[37] Ibid.

For other regulated entities, capital structure is set on a case-by-case basis. The other regulated entities include electricity generator (Ontario Power Generation ("OPG"))[38] and natural gas utilities (Enbridge Gas Inc. ("Enbridge Gas")[39] and EPCOR Natural Gas Limited Partnership ("EPCOR Natural Gas")).[40] EPCOR Natural Gas' equity thickness of 40% has remained unchanged since 2006.[41]

Since 2006, the OEB has reassessed the capital structure for the following regulated utilities: OPG in 2008, 2014 and 2017, Enbridge Gas Distribution Inc. in 2007 and 2013, Union Gas Limited in 2006 and 2012, and Enbridge Gas in 2023, following applications from these utilities/intervenors. Only two of the eight reassessments have led to a change in equity ratio (for OPG in 2014 and Enbridge Gas in 2023 – see Figure 8 for further details).

2.5.5 Prescribed interest rates

The OEB uses a formulaic approach, approved in 2006, to set prescribed interest rates for Ontario electricity distributors and natural gas utilities for regulatory accounts under the Uniform System of Accounts ("USoA"). The prescribed interest rates also apply to the regulatory accounts of other rate or payment amounts regulated entities when authorized by the OEB to use these rates. The key objective of this approach is to provide a methodology that can be updated automatically, reflect market rates, and is responsive to changes in market conditions.[42]

The interest rates are set for two types of regulatory accounts:

i. Deferral and variance accounts ("DVAs"): The prescribed interest rate for DVAs equals the three-month bankers' acceptance rate (as published by the Bank of Canada "BoC"), plus a fixed spread of 25 basis points ("bps");[43] and
ii. Construction work in progress ("CWIP"): The prescribed interest rate for CWIP equals the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate yield[44] ("FTSE mid-

[38] OPG's equity thickness of 45% has remained unchanged since 2006. Source: OEB. EB-2020-0290. Ontario Power Generation Inc. settlement proposal. July 16th, 2021.

[39] The OEB approved an increase in Enbridge Gas' equity thickness from 36% (2006 to 2023) to 38% applicable for 2024 rates. Source: OEB Decision dated December 21st, 2024 in EB-2022-0200.

[40] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

[41] OEB. Decision and Order EB-2022-0028. EPCOR Electricity Distribution Ontario Inc. Application for electricity distribution rates and other charges beginning January 1, 2023. June 15th, 2023.

[42] OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006.

[43] Ibid.

[44] LEI notes that under the OEB's original decision dated November 28th, 2006, this index was described as "Scotia Capital Inc. All Corporates Mid-Term Average Weighted Yield", which has since evolved to the FTSE Canada Mid Term Bond Index All Corporate Yield. Source: OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006.

term index"), and the OEB, under contract, obtains this yield rate from PC Bond Analytics, a business unit of FTSE.[45]

The rates are reviewed quarterly, and updated only if the formulaic approach results in a change in interest rates of 25 bps or more.[46,47]

2.5.6 Cloud computing deferral account

Effective December 1st, 2023, per the Accounting Order (003-2023), the OEB implemented a generic deferral account that records the incremental costs, net of savings, of cloud computing implementation. The recorded costs are subject to OEB's approval in the utilities' respective subsequent rate proceedings for each utility.[48] Incremental costs are costs outside of what is embedded in rates i.e. when amounts are recorded, they should represent impacts that are more than what utilities are already compensated for.[49]

Prior to the cloud computing accounting order, the OEB did not distinguish the accounting treatment for cloud computing related operating/capital expenses and general operating/capital expenses.

To compensate for the additional risks and benefits (if any) associated with the change in methodology, the OEB aims to determine in this Generic Proceeding what type of interest rate, if any, is warranted for the above deferral account.

2.6 Historical context and timeline of key relevant events

Since 2006, there have been a number of key events related to cost of capital issues.

With regards to setting ***prescribed interest rates*** for DVA and the CWIP account, the current methodology has been in place since 2006.[50]

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[45] OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006.

[46] Ibid.

[47] For instance, the approved deferral and variance accounts ("DVA") interest rate of 5.49% for Q4 2023 was retained in Q1 2024 and Q2 2024, as interest rate was relatively stable during that period and had not changed by 25 bps or more.

[48] OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

[49] OEB. Q&A: Cloud computing implementation. Costs generic deferral variance account. February 15th, 2024.

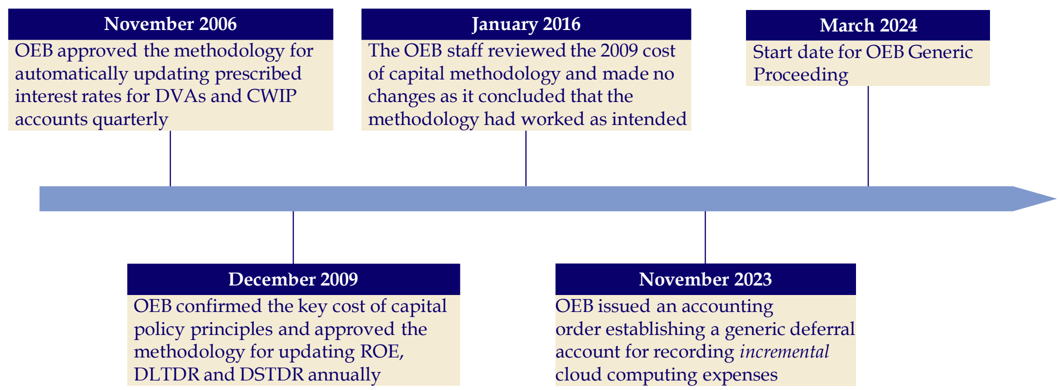
[50] In June 2020, the OEB decided to set the 2020 Q3 prescribed interest rates for DVA using a different approach from the methodology approved in 2006. This was done without consultation to expeditiously respond to *the unprecedented state of emergency arising from the COVID-19 pandemic*. The OEB used the average of the 2020 Q2 DVA interest rate and the 2020 Q3 DVA interest rate, both calculated with the OEB's approved methodology in 2006, as the final 2020 Q3 DVA interest rate. The decision was expected to smooth the impact of the COVID-19 pandemic, and align with the average of AA-, A-, and BBB-rated Canadian Corporate bond yields since May 2020.[50] However, following the decision, the OEB received comments from several intervenors against

As for setting ***cost of capital parameters***, the OEB continues to utilize the methodology approved in 2009. In 2016, a review[51] by OEB staff concluded the methodology continues to *work as intended*.

With regards to ***deferral account for cloud computing costs***, the accounting order for establishment of a generic deferral account to record incremental cloud computing costs was issued by the OEB in November 2023.

The timeline is summarized below in Figure 6.

Figure 6. Timeline of key events relevant to the Generic Proceeding



The subsequent sections briefly discuss key developments associated with this timeline.

2.6.1 Approval of accounting interest rates methodology for regulatory accounts (2006)

In May 2006, the OEB announced its plan to implement a formulaic approach for setting interest rates used by Ontario natural gas utilities and electricity distributors for regulatory accounts under the USoA.

The OEB Staff proposed a prescribed one-year interest rate for deferral and variance accounts based on the one-year Canada treasury bill and a two-tier approach for CWIP. For CWIP, the OEB Staff stated that *some utilities who use short-term financing during the construction phase, replace it with mid-term financing when the completed asset is placed in service*, while *other utilities finance construction as part of their general borrowing program or from equity*.[52]

Staff noted that calculating a blended rate on a utility-specific basis is *burdensome for utilities to constantly determine this rate for their utility*, and monitoring all regulated utilities' individual rates

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the decision. Considering the comments, in July 2020, the OEB decided to re-establish the 2020 Q3 DVA interest rate using the methodology approved in 2006 and continued this practice since. Source: OEB. 2020 Q3 Prescribed Interest Rates. June 16th, 2020.

[51] OEB. OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

[52] OEB. EB-2006-0117. Board Staff Proposal Paper. Interest Rates for Regulatory Accounts of Utilities. May 26th, 2006. Page 8.

is *not practical for the Board*.[53] As such, the OEB Staff proposed to use two market-based proxy rates, depending on the length of the construction period. Specifically, the OEB Staff proposed interest rates for construction projects for:

(i) up to one year to be based on the one-year Canada treasury bill rate, and

(ii) more than one year to be based on the FTSE mid-term index[54]

The OEB opted for different proxy rates in its decision.[55] As mentioned earlier, for DVAs, the OEB approved an interest rate equal to the three-month bankers' acceptance rate plus a fixed spread of 25 bps. The OEB linked the interest rates for DVAs to a short-term interest rate *due to the temporary nature of the accounts to which they relate and disposition of account balances in rates over a relatively short period of time*.[56]

For CWIP, *for ease of administration and record keeping by users,*[57] the OEB approved an interest rate equal to the FTSE mid-term index, applicable to all projects under construction, regardless of the construction period.

As described above in the summary of the status quo, the two prescribed rates are reviewed quarterly and updated if the change is 25 bps or more.[58]

2.6.2 Review of cost of capital policies for Ontario (2009)

In the *Report of the Board on Cost of Capital and 2nd Generation Inventive for Ontario's Electricity Distributors*, dated December 20th, 2006 ("2006 Report"), the OEB adopted a modified capital asset pricing model ("CAPM") methodology using an equity risk premium ("ERP") approach.[59] The formulaic approach resulted in ROE being determined based on a Long Canada Bond Forecast ("LCBF") rate plus an ERP.[60]

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[53] Ibid.

[54] OEB. EB-2006-0117. Board Staff Proposal Paper. Interest Rates for Regulatory Accounts of Utilities. May 26th, 2006.

[55] OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006.

[56] OEB. EB-2006-0117. Board Staff Proposal Paper. Interest Rates for Regulatory Accounts of Utilities. May 26th, 2006. Page 3.

[57] OEB. EB-2006-0117. Approval of accounting interest rates methodology for regulatory accounts. November 28th, 2006. Page 9.

[58] Ibid.

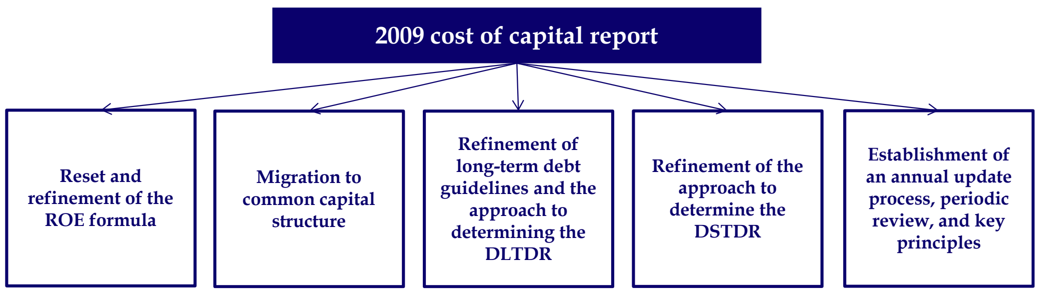
[59] The OEB also considered other ROE estimates from participants based on CAPM, discounted cash flow ("DCF") approach, and Comparable Earnings ("CE") approach. However, it decided to retain its existing ERP-based approach, which resulted *in a return sufficient for distributors to continue to attract capital*. Source: OEB. Report of the Board on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors. December 20th, 2006.

[60] OEB. Report of the Board on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors. December 20th, 2006.

The formulaic approach for determining the cost of capital parameters, i.e., ROE, DLTDR, and DSTDR, was selected given the significant number of regulated utilities under the OEB's jurisdiction.[61] The OEB noted that the formula-based approach *reduces the need for complex, annual risk assessments, while still reflecting major changes in the capital markets*, and hence *is a practical necessity in Ontario, given the large number of rate regulated entities.*[62]

In February 2009, the OEB initiated a consultative process in reviewing its cost of capital policies as set out in 2006,[63] which culminated in a policy report issued in December 2009. The report set out the OEB's updated approach and methodologies to determine the cost of capital. In particular, the report refined the OEB policies in five ways, as shown in Figure 7 below.

Figure 7. Key components of 2009 cost of capital report



Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

The five approaches are briefly discussed below.

<u>Reset and refinement of the ROE formula</u>:

In 2009, the OEB concluded that *in order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital, the Board has determined that its current formula-based ROE approach needs to be reset and refined.*[64]

The OEB determined that the LCBF continues to be an appropriate base as set out in the 2006 Report to begin the ROE calculation. Based on the ERP recommendations derived from multiple approaches that were provided by participants in the consultation, the OEB determined an initial ERP of 550 bps, which included an implicit 50 bps for transactional costs, to be appropriate.

[61] The OEB regulated over 80 utilities (primarily electricity distributors) in 2009. As of December 2022, the OEB regulated over 60 utilities.

[62] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009. Page 27.

[63] The ROE formula set out in the 2006 report is $ROE_t = 9.35\% + 0.75 \times (LCBF_t - 5.50\%)$.

[64] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009. Page i.

As described earlier in the status quo section, the resulting base ROE was determined to be 9.75%, assuming a base LCBF yield of 4.25%.[65,66] In addition, the ROE formula was refined to reduce sensitivity to changes in government bond yields driven by monetary and fiscal conditions which are not reflective of changes in the utility ROE. To make periodic adjustments to the base ROE, the OEB considered an LCBF spread, and a utility bond spread in the formula, subject to a 0.5 adjustment factor (as illustrated in Figure 3 earlier).[67]

Migration to a common capital structure

The OEB decided that the capital structure of 60% debt and 40% equity, initially determined in 2006, remained appropriate for electricity distributors and transmitters. The capital structure would be determined on a case-by-case basis for electricity generators and natural gas utilities.[68]

The capital structure for OEB-regulated entities has been relatively steady over the last two decades. The equity thickness currently approved by the OEB for various regulated entities is shown in Figure 8.

Figure 8. OEB allowed equity thickness

Regulated entities	OEB approved equity thickness*
Electricity distributors and transmitters	40%
Electricity generation (OPG)**	45%
Natural gas distribution (Enbridge Gas)***	38%
Natural gas distribution (EPCOR Natural Gas)	40%

* The equity thickness for OEB-regulated entities, with the exception of Enbridge Gas and OPG, has remained unchanged since 2006.

** For OPG, the OEB reduced the allowed equity thickness from 47% to 45% in EB-2013-0321, following submissions from various participants contending that OPG's business risks had reduced relative to prior OEB assessment.

*** For Enbridge Gas, the OEB approved an increase in equity thickness from 36% to 38% applicable for 2024 rates in EB-2022-0200 (Order dated December 21st, 2023).

Source: OEB.

Refinement of long-term debt guidelines and the DLTDR formula

The OEB noted that it would primarily rely on the embedded or actual cost for existing long-term debt instruments with respect to the determination of the DLTDR.[69] Third-party debt with a fixed

[65] Ibid.

[66] Base ROE = Base LCBF + ERP.

[67] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

[68] Ibid.

[69] Ibid.

rate would generally *be afforded the actual or forecasted rate, which is presumed to be a "market rate"*.[70] However, the OEB recognized that the DLTDR would act as a proxy or ceiling for market-based rates by the OEB under certain circumstances.[71]

The approach (summarized in Figure 4) is consistent with the methodology adopted in the 2006 Report, representing a fair market rate for a long-term debt instrument. The LCBF is the same as that used to calculate the ROE. The only change is the source of the bond yields, which was revised from BBB/A-rated Canadian Corporate bond yield series obtained from PC Bond[72] to 30-year A-rated Canadian utility bond yield obtained from Bloomberg. The change of data source *reduces costs and work and increases transparency of the calculations*.[73] OEB did not consider *the changes in methodology will have any material impact on the calculated DLTDR*.[74]

Refinement of the DSTDR formula

The OEB established a revised DSTDR formula in 2009. As indicated earlier, DSTDR was based on the estimates of the spread of a typical short-term loan for an R1-low utility over the 3-month Bankers' Acceptance rate from major Canadian banks. This was a change over the previous 2006 methodology (introduced in cost of service applications for 2008 distribution rates), specifically in the spread above the 3-month BA rate, which was previously fixed at 25 basis points.

The DSTDR only applies to electricity transmitters and distributors, based on a deemed capital structure of 40% equity, 56% long-term debt and 4% short-term debt (for other regulated entities, OEB considers actual debt rates).

Annual update process, periodic review, and key principles

To assess the reasonableness of formula-generated results relative to prevailing economic and financial conditions annually, the OEB decided to examine the values produced by the cost of capital methodology. Further, the OEB elected to conduct periodic review every five years on its formulaic ROE adjustment mechanism, providing a balance between the need to ensure that the resulting ROE continues to meet the FRS, and the objective of maintaining regulatory efficiency

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[70] Ibid. Page 53.

[71] There are five circumstances: 1) the DLTDR for affiliate debt with a fixed rate is used as a ceiling on the rate allowed for that debt; 2) the DLTDR for debt with a variable rate is used as a ceiling on the rate allowed for that debt, regardless of affiliate or not; 3) the DLTDR is used for an electricity distributor with no actual debt; 4) the DLTDR for debt that is callable on demand is used as a ceiling on the rate allowed for that debt; and 5) an OEB panel determined the debt treatment, including the rate allowed, and the onus was placed on the utility to establish the need for and prudence of its actual and forecasted cost of debt. Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

[72] The PC Bond data was, prior to mid-2007, produced by Scotia Capital Inc., and publicly available from Statistics Canada and the Bank of Canada

[73] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009. Page 54.

[74] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009. Page 55.

and transparency.[75] The OEB commenced a review in 2014 and published the concluding staff report in 2016, which is briefly discussed in the section below.

2.6.3 Review of the methodology of the cost of capital for Ontario's regulated utilities (2016)

Per the OEB's commitment to review the cost of capital methodology every five years, in 2014, OEB Staff commenced a review of:

i) the results of the policy flowing from the formulae for the ROE, DLTDR, and DSTDR since 2009;

ii) actual financial results of rate-regulated utilities based on recent available data; and

iii) performance of the existing policy with respect to the expected outcomes.

Between 2010 and 2015, allowed ROEs ranged between 8.93% and 9.85%, with most results close to the middle of the range and with moderate fluctuations. The OEB staff concluded in 2016 that this accurately reflected *the prolonged period of low interest rates, the slow but steady recovery from the 2008-2009 financial crisis and the specification and calibration of the formulae in the 2009 Cost of Capital Report.*[76] The OEB also examined the bank survey for the DSTDR calculation and concluded that the process had worked well.[77,78]

The OEB staff also concluded that the methodology adopted in 2009 had worked as intended, i.e., *[m]ovement in the parameters [had] followed macroeconomic trends and activity, and [had] not resulted in excessive or anomalous volatility*.[79]

The OEB did not initiate the subsequent methodology review after five years (2019).[80] This Generic Proceeding aims to review the cost of capital methodologies in 2024.

2.6.4 OEB Accounting Order for a deferral account to record incremental cloud computing costs (2023)

The OEB's current ratemaking regime is based on an incentive rate-setting mechanism ("IRM"). Under the IRM, rates /revenue for the base year are typically determined using a cost-of-service model and the rates for subsequent years of the incentive rate-setting ("IR") period (typically 5 years) are indexed to a formula. The formula is mostly linked to the inflation factor and

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[75] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

[76] OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016. Page 4.

[77] Since inception in 2010, all participating banks had fully participated in all years except one and there had been no concern expressed by the industry or other stakeholders about the process or the results to OEB.

[78] OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

[79] OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016. Page 1.

[80] LEI has considered 2014 (the commencement of the review) the year of the first review.

productivity factors (which include stretch factors) approved by the OEB. The IRM also includes provisions for material incremental capital investments (subject to OEB approval), i.e., beyond the capital expenditure covered by the IRM formula.[81]

The design of the IRM is tailored to accommodate approved material incremental capital expenses, but not incremental operating (or O&M) expenses. Regulated utilities can earn an ROE on their rate base (which is primarily made up of capitalized assets in use) but cannot earn a return on their operating expenses. As such, the current IRM design incentivizes utilities to make in-house infrastructure investments for their computing and storage needs, rather than opting for a cloud computing service (as it is categorized as an O&M expense). The cloud computing costs cannot be amortized over a longer time horizon, despite the long-term benefits of switching to this model.[82]

In addition, the pricing structure from most cloud computing service providers is based on a pay-as-you-go payment model, which may not be easily incorporated into the IRM formula. The OEB retained KPMG in May 2023 to prepare a report on cloud computing arrangements for utilities in the regulatory environment.[83] The report provides eight options for accounting treatment of cloud computing costs and details the pros and cons for each option.

The OEB has opted to establish a generic deferral account (effective December 1st, 2023), which will record the *incremental costs, net of the saving,* of cloud computing implementation, i.e., only the incremental costs beyond the costs approved in the base year. The recorded costs will be subject to OEB's approval in the utilities' respective subsequent rate proceedings.

The carrying charges (or interest rates) for DVA are updated quarterly by the OEB. However, in this Generic Proceeding, the OEB would like to determine if the risk profile of the transition to cloud computing solutions warrants an additional risk premium over and above the carrying charges, i.e., a higher rate than the prescribed interest rates.[84] LEI's recommended approach for determining the appropriate carrying charge is described in Section 4.14.

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[81] OEB. Handbook for Utility Rate Applications. October 13th, 2016.

[82] The OEB has noted in its Accounting Order (003-2023) that costs of cloud computing can be overestimated if the utility implements the transition during the base year due to significant up-front costs related to transition costs. OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

[83] OEB. Appendix B to Accounting Order (003-2023). KPMG Report on regulatory options for the treatment of cloud computing costs. September 2023.

[84] Ibid.

3 Principles and approach

3.1 Principles

LEI has closely considered several underlying principles and objectives formulating recommendations in this report. These include:

- Cost of capital principles adopted by the OEB;
- Regulatory accounting principles adopted by the OEB; and
- OEB's mission and mandate.

LEI then synthesized five guiding principles consistent with this source material.

Cost of capital principles

With regards to the issues related to the cost of capital parameters, the OEB confirmed six key regulatory principles with respect to its cost of capital policy in its 2009 report (*EB-2009-0084)*, which are described below.[85]

1) **Fair Return Standard ("FRS"):** The FRS establishes a legal framework for setting a fair and reasonable return on capital for regulated electricity and gas utilities, as described in the text box below.

The Fair Return Standard ("FRS")

The FRS was articulated by the National Energy Board ("NEB") in its *RH-2004 Phase II Decision* (related to TransCanada PipeLines Cost of Capital), when it stated that three requirements must be satisfied to determine a fair and reasonable return on capital:

a) **Comparable investment standard**: a fair or reasonable return on capital should be comparable to the return available from the application of invested capital to other enterprises of like risk;

b) **Financial integrity standard**: should enable the financial integrity of the regulated enterprise to be maintained; and

c) **Capital attraction standard:** should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions**.**

Source: NEB. RH-2-2004. Phase II Reasons for Decision, TransCanada PipeLines Limited cost of capital. April 2005.

It is important to note that [*m]eeting the standard is not optional; it is a legal requirement*.[86]

2) **The overall ROE must be determined solely on the basis of a company's cost of equity capital**, regardless of equity ownership, and any resulting rate increase must be an irrelevant consideration in determining the appropriate ROE for regulated utilities. The Federal Court

[85] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

[86] Ibid. Page i.

of Appeal established the principle in the case *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*.[87]

3) **Efficient amount of investment:** the cost of capital has to be determined to ensure that an efficient amount of investment occurs in the public interest to balance the impacts on both customers and shareholders (i.e., not so high that the Ontario consumers are disadvantaged, and not so low that the regulated utilities do not have sufficient incentive to make investments that are in the public interest).

4) **Predictability, transparency, and stability** in OEB decisions and outcomes so that investors, utilities, and consumers have reasonable confidence in making long-term decisions.

5) **Systematic and empirically based approach:** the OEB's methodology should be systematic, relying on economic theory and empirically derived from objective, data-based analysis.

6) **Minimize the time and cost of administering the framework**, particularly because the OEB has to determine the appropriate cost of capital for more than 60 regulated utilities. Costs imposed on regulated entities and the OEB should not exceed the available benefits, which can be met through a simple process that not only reflects the concerns of relevant parties, but also reduces process requirements.

Regulatory accounting principles

With respect to issues related to regulatory accounting (related to 'prescribed interest rates' and 'cloud computing deferral account'), LEI was guided by the established regulatory principles and practices laid out by the OEB in Accounting Order (003-2023), which are reproduced in the text box below.

OEB established principles and practices related to regulatory accounting

The accounting and regulatory reporting requirements should:

a) be based on sound regulatory principles including ***fairness, minimizing intergenerational inequity and minimizing rate volatility***;
b) ***balance the effects on both customers and shareholders*** when taking into account financial accounting requirements; and
c) be primarily driven by the objective of ***just and reasonable rates***.

Source: OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

[87] The NEB established a mechanism to automatically adjust the ROE (the 1995 decision). In 2001, TransCanada PipeLines Ltd. ("TransCanada") applied for a review of the 1995 decision and the NEB rejected the TransCanada's proposed new methodology for determining cost of capital and determined to continue using the adjustment mechanism set out in the 1995 decision. TransCanada then filed an appeal regarding the NEB's decision but failed to show that the NEB erred in taking customer interests into account when determining the rate of return on capital that it would allow TransCanada to earn. Source: TransCanada PipeLines Limited v. National Energy Board, 2004 FCA 149.

OEB mission and mandate

The outcome of the Generic Proceeding will affect the rates paid by residential and business consumers for electricity and gas services. As such, the recommendations in this report aim to protect consumer interests and ensure fairness to both consumers and utilities, consistent with the OEB's mission and mandate described in the text box below.

OEB's Mission and Mandate

The OEB's mission is to *deliver public value through prudent regulation and independent adjudicative decision-making which contributes to Ontario's economic, social and environmental development.*

As required under provincial legislation, the OEB's mandate is to regulate Ontario's energy sector. The OEB has regulated the natural gas sectors since 1960 and the electricity sector since 1999.

For consumers, the OEB's mandate includes:

- Protecting the interests of consumers by setting the rates and prices that utilities can charge;
- Providing the information consumers need to better understand the rules protecting them and their responsibilities;
- Protecting consumers' interests in retail electricity and natural gas market; and
- Addressing the particular needs of low-income consumers through the establishment and oversight of utility customer service rules and delivering financial assistance programs.

For industry, the OEB's mandate includes:

- Setting the delivery rates for electricity and natural gas utilities and monitoring their financial and operational performance;
- Approval of new electricity transmission lines and natural gas pipelines that serve the public interest;
- Approval of mergers, acquisitions, and dispositions by electricity and natural gas utilities;
- Setting the payments to OPG for electricity generated by its regulated nuclear and hydroelectric generation facilities;
- Establishment and enforcement of codes and rules to govern the conduct of utilities and other industry participants; and
- Licensing entities in the electricity sector and natural gas marketers.

Source: OEB. Mission and mandate. Accessed on April 17th, 2024.

Considering the abovementioned principles, LEI has devised five overarching principles to evaluate its potential alternatives and arrive at its final recommended approach. Overall, LEI proposes evolutionary rather than revolutionary changes in response to the issues identified in the Generic Proceeding. The principles include the following:

1. ***Meeting the FRS***, which is a legal requirement;

2. ***Simple to administer relative to the status quo***, i.e., the costs (if any) of transitioning away from the status quo and administering the recommended alternative are reasonable;
3. ***Transitioning away from the status quo only if the associated benefits are material*** as there is limited merit in modifying aspects of the methodology that have worked well;
4. ***Fairness in approach to consumers and utilities***, consistent with the OEB's mission and mandate, to ensure efficient investments; and
5. ***Predictability and transparency*** in the recommended approach to ensure that the outcomes from the proposed methodology are relatively stable over a long-term time horizon.

3.2 Approach

In Section 4, LEI presents recommendations for each issue in OEB's approved Final Issues List. For each substantial issue, LEI has adopted the following four-step approach:

- **Step 1 - Status quo:** briefly describes OEB's current practice.

- **Step 2 - Relevant jurisdictional review and/or literature review:** reviews relevant regulatory actions and decisions in select jurisdictions regarding the issue to provide insights relevant to Ontario. For issues where literature review is more relevant, LEI has presented relevant literature for the issues in question.

- **Step 3 - Potential alternatives (for approaches associated with relevant issues):** evaluates potential alternatives based on the findings in Step 1 (status quo analysis) and Step 2 (relevant jurisdictional analysis). LEI ***did not aim to present all possible alternatives*** but has presented alternatives that the OEB and other participants in the Generic Proceeding may find most useful to consider.

- **Step 4 - Recommendations:** a recommended approach was chosen from the list of evaluated alternatives, considering principles outlined in Section 3.1, with primary consideration of the FRS for issues related to the cost of capital.

3.2.1 Selection of jurisdictions

The jurisdictional review associated with Step 2 provides an understanding of relevant regulatory actions and decisions, highlighting approaches and lessons learned that may be unique to and/or particularly relevant to the Ontario context.

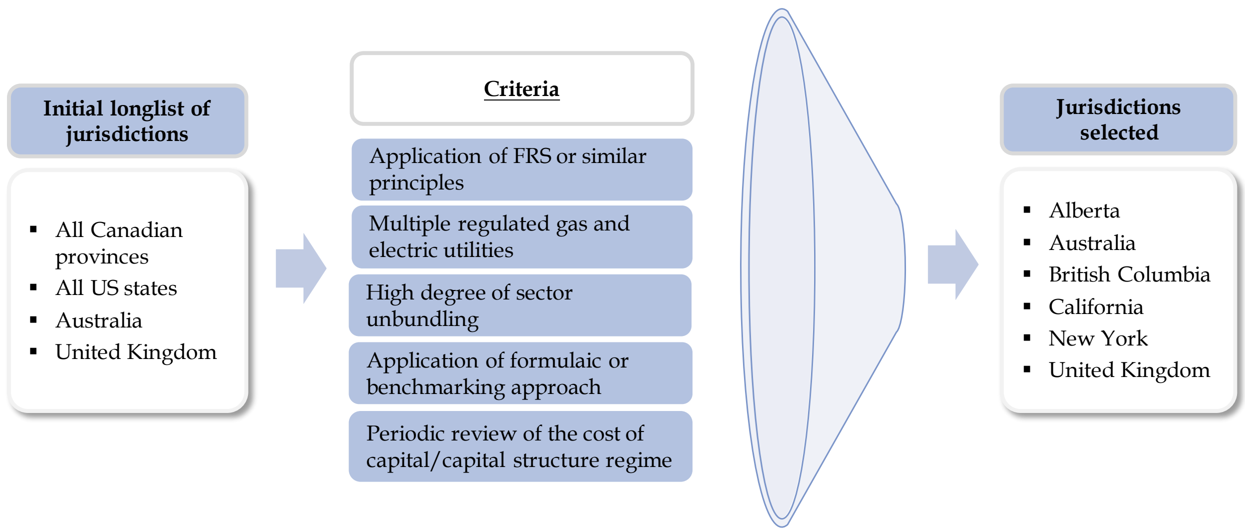
LEI's criteria in selecting jurisdictions for this report include:

1. ***application of FRS or similar principles*** in the determination of the appropriate ROE;
2. jurisdiction with ***multiple regulated gas and electric utilities***;
3. ***high degree of sector unbundling***, particularly with regard to the generation sector;

4. ***application of a formulaic or benchmarking approach*** to determining the cost of capital parameters; and
5. ***periodic review*** of the cost of capital/capital structure regime.

LEI began with a long list comprising US states, Canadian provinces, the United Kingdom ("UK"), and Australia. As shown in Figure 9 below, after applying the five criteria listed above, LEI selected six jurisdictions for further study: Alberta, Australia, British Columbia ("BC"), California, New York ("NY"), and the United Kingdom ("UK").

Figure 9. Selection of jurisdictions for further study



In addition to the North American jurisdictions, LEI included the UK and Australia because they have similar regulatory regimes to Ontario, and the cost of capital methodology adopted in these countries can provide valuable insights for Ontario. For instance, regulators in both these jurisdictions frequently review cost of capital parameters and provide thorough reasons for their decisions.

A summary of the selected jurisdictions is shown in Figure 10 below.

Figure 10. Summary of selected jurisdictions

Jurisdiction	2023 Population (millions)	2023 Electricity demand (TWh)	Number of regulated electric and gas utilities	Application of FRS or similar principle	Cost of capital approach	Cost of capital/capital structure review frequency
Alberta	4.8	86	21	FRS	Uniform formula across sectors applied since 2004 (discountinued in 2009)	Review every 5 years, subject to mid-term reopeners; ROE updated annually
Australia	26.8	188	43	An unbiased estimate of the expected efficient return, consistent with the relevant risks involved in providing regulated network services	Uniform formula across sectors applied since 2018	Reviewed every 4 years; Cost of debt updated annually, but not other parameters
British Columbia	5.5	65 (2019)	18	FRS	Benchmark*	Not scheduled
California	39.1	288 (2022)	6	Fair and reasonable rate of return** on capital investments	Case by case; A uniformCCM has been adopted since May 2008 for large utilities to automatically adjust their cost of capital parameters, not applicable for small utilities	Reviewed every 3 years
New York	19.6	144	18	Fair and reasonable rate of return on capital investments	Case by case; Bill A07502 has been introduced in May 2023 and referred to the Committee on Energy in January 2024 to establish a single rate of return on equity for all regulated utilities based on the generic financing methodology, but has not passed as of Apirl 23rd, 2024	Not scheduled
United Kingdom	67.6 (2022)	310	841	Fair return*** on utilities' activities while controlling the end cost to consumers	Formulae varied for different sectors applied since 2013	Reviewed every 5 years; Cost of debt updated annually, but not other parameters
Ontario	15.8	137.1	70+	FRS	ROE updated annualy and uniformly applicable for all utilities; Capital structure adjusted based on sector-specific risk profile	Review methodology every 5 years; ROE updated annually

* The benchmark methodology requires the BC Utilities Commission ("BCUC") to designate a Benchmark Utility and set cost of capital parameters of the Benchmark Utility. The BCUC then uses the Benchmark Utility as a reference to set cost of capital parameters of other regulated utilities by adjusting various risk factors. Source: BCUC.

** The principle of a fair and reasonable rate of return was established in the *Bluefield* and *Hope* decisions of 1923 and 1944, respectively. *Bluefields* states that *the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties*; *Hope* states that *the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks, and should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital*. Source: US Supreme Court.

*** The return should properly reflect the risks faced in the business and prevailing financial market conditions. Source: Office of Gas and Electricity Markets ("Ofgem")

A subset of the shortlisted jurisdictions is reviewed for each of the issues discussed in Section 4, depending on the respective issue and its relevance. Furthermore, where appropriate, LEI has included references to jurisdictions other than the six jurisdictions shortlisted in Figure 9.

3.2.2 Impact of the energy transition on the cost of capital

The term "energy transition" refers to a shift from an energy system that primarily relies on fossil fuel-based energy sources (such as natural gas, coal and oil) to net zero-emitting renewable energy sources (such as batteries, solar and wind power, and carbon capture and storage). Electrification of heating and transportation is often a large part of such policies, with impacts on regulated utilities in both the electricity and gas sectors. The pace of technological change is also impacting how and when customers consume (and sometimes generate) electricity.

However, while the energy transition is bringing dramatic changes to the sector as a whole, the focus when considering cost of capital implications is not whether and how fast the industry is changing but whether, for regulated businesses, the volatility of net cash flows is changing or there is an increased risk of inability to attract capital or recover associated investments. Neither appears likely in the forthcoming regulatory period. This is because the pace of change remains measured, and regulated utilities can use various regulatory mechanisms such as DVAs, Z factor, I factor, and off-ramp mechanisms to manage net cash flow volatility (if any).

By design, regulated entities face less risk than competitive businesses. Existing regulatory mechanisms address load fluctuations, capital recovery, and unforeseen events, whether caused by energy transition or not. Given that ratemaking processes directly deal with these issues and equity thickness is the lever used to address differences between regulated sectors (see Section 4.2.4 wherein LEI has recommended adjusting equity thickness as the appropriate lever for addressing material changes in risk profile), LEI does not believe energy transition issues are a large driver in reviewing the process of setting the cost of capital.

4 Issues identified in the Generic Proceeding issues list

In this section, LEI has reviewed all issues identified in the 'Final Issues List' approved by the OEB.[88]

For each issue, LEI has: (i) described the status quo; (ii) provided relevant jurisdictional/literature review, (iii) discussed potential alternatives, and (iv) suggested recommendations, consistent with the principles and approach outlined in Section 3.

4.1 General issues – impact of source of the capital and types of ownership on the cost of capital

Issue 1: ***Should the approach to setting cost of capital parameters and capital structure differ depending on***:

a) The ***source of the capital*** (i.e., whether a utility finances its business through the capital markets or through government lending such as Infrastructure Ontario, municipal debt, etc.)?

b) The ***different types of ownership*** (e.g., municipal, private, public, co-operative, not for profit, Indigenous / utility partnership, etc.)

The sources of capital are typically equity and/or debt.[89] Debt funding can come from banks, corporate bonds, or public lending institutions (such as Infrastructure Ontario).[90] Loans received directly by the government or its own controlled agency/development bank often have favourable rates relative to financing obtained from commercial banks and bond issuances.[91] Issue 1a relates to whether the source of capital should matter for OEB when setting the cost of capital and capital structure methodologies.

With respect to ownership structure, although OEB-regulated entities operate as commercial entities, the ownership structures for these entities vary.[92] The regulated entities include publicly/provincially owned utilities (e.g., Hydro One Limited and Ontario Power Generation

[88] OEB. EB-2024-0063. Generic Proceeding – Cost of Capital and Other Matters; Cancellation of April 23, 2024 Issues Day and Approved Issues List. April 22nd, 2024.

[89] The capital funding can also come from customer contributions (such as customer security deposits) and government grants. However, such sources of funding are offset from the rate base. As such, the utilities cannot earn a return on the value of investments made from customer contributions and grants. Before the transition to International Financial Reporting Standards ("IFRS") in January 2011, such funding was considered as an offset to property, plant, and equipment ("PP&E") accounts. Since 2011, customer contributions and grants are recognized as deferred revenue and amortized over the life of the assets. For ratemaking purposes, the balance of the deferred revenue account is included as an offset to the rate base. Source: OEB. Accounting Procedures Handbook for Electricity Distributors. Issued: December 2011. Effective: January 1st, 2012.

[90] Public lending institutions such as Infrastructure Ontario typically focus on *long-term financing to public sector clients*. As such, LEI has limited its focus to long-term debt financing in Issue 1a.

[91] OECD. Infrastructure Financing Instruments and Incentives. 2015. Page 51.

[92] OEB. OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

Inc.), municipally owned utilities (e.g., Toronto Hydro-Electric System Limited and Alectra Utilities Corporation), privately owned utilities (e.g., Enbridge Gas Inc. and Canadian Niagara Power Inc.), co-operative owned utilities (e.g., Cooperative Hydro Embrun Inc.), and indigenous-owned utilities (e.g., Attawapiskat Power Corporation).[93,94] Issue 1b relates to whether ownership structures lead to different outcomes and if ownership type should matter for OEB when setting the cost of capital and capital structure methodologies.

4.1.1 Status quo

This section discusses the prevailing OEB policies associated with considering the source of capital and ownership type when setting the cost of capital parameters and capital structure.

Source of funding

Among OEB regulated entities, 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.[95]

For electricity distributors and transmitters, the OEB's stated policy primarily relies on embedded or actual costs for existing long-term debt instruments. DLTDR serves as a proxy (if the distributor has no debt) or a ceiling (if the actual rate is higher than DLTDR).[96,97]

Given that the OEB considers the actual long-term debt rates in most cases, its current methodology already implicitly considers the impacts of different funding sources. For example, actual debt financing to regulated entities from public lending institutions at potentially lower interest rates is already accounted for in the DLTDR, one of the key cost of capital parameters, when approving annual revenue requirements for the rebasing year.

Types of ownership

In 2009 (EB-2009-0084), the OEB determined that the ownership structure of a utility should not be a relevant factor when determining the cost of capital:

"*In Ontario, **utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities**. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated*

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93 S&P Global.

94 The OEB also regulates utilities structured as partnerships between indigenous communities and private companies. For example, Wataynikaneyap Power LP is a licensed transmission company equally owned by 24 First Nations communities (51%), in partnership with Fortis Inc. and other private investors (49%). Source: Wataynikaneyap Power LP.

95 OEB. OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

96 Ibid.

97 DLTDR can also be applied in other limited cases, which are described in Section 4.6.1.

entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. ***The Board sees no compelling reason to adopt different methods of determining the cost of capital based on ownership*** (emphasis added)."[98]

4.1.2 Relevant jurisdictional/literature review

This section summarizes the approach taken by other jurisdictions in considering sources of funding and ownership types when determining cost of capital parameters.

4.1.2.1 Considering the source of funding in setting the cost of capital parameters

With respect to considering the source of funding in allowing debt rates, LEI reviewed the current methodologies in Alberta, the UK, and Australia.

Similar to Ontario, Alberta allows the cost of actual debt rates to the utilities (which implies lower lending rates from public lending institutions, if any, are considered in the methodology). On the other hand, UK and Australia consider a uniform benchmark debt rate, i.e., no consideration of the source of debt funding. The three examples are discussed briefly below.

Alberta: The cost of debt is not set by the AUC, instead, it is *determined in the market, based on who is willing to lend the utility money*.[99] Further, the AUC determines the weighted average cost of capital ("WACC") based on the approved ROE and capital structure, as well as *the actual embedded cost of debt*.[100,101]

Australia: The Australian Energy Regulator ("AER") sets the benchmark return on debt allowance using a 10-year simple trailing average of the BBB+ corporate bond yield from several third-party providers, updated annually.[102,103] The AER methodology does not alter the benchmark return on debt based on source of funding. Instead of determining returns on a case-

98 OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009. Page 25-26.

99 AUC. Fair rate of return for investors. Accessed April 29th, 2024.

100 AUC. Decision 27388-D01-2023. 2024 – 2028 Performance-based regulation plan for Alberta electric and gas distribution utilities. October 4th, 2023. Page 1.

101 AUC. Decision 28583-D02-2024. Apex Utilities Inc. 2024 Annual performance-based regulation rate adjustment. March 15th, 2024.

102 AER. Rate of return instrument. Explanatory statement. February 2023.

103 The AER targets a 10-year BBB+ corporate bond yield. However, as there is no such index available, it instead uses a 1/3rd to 2/3rd weighted average on the yields on A-rated and BBB-rated bond indexes. The yield data is averaged across Bloomberg, Thomson Reuters, and the Reserve Bank of Australia data providers. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

by-case basis, the benchmark rate of return, comprising allowed ROE, return on debt, and gearing ratio/deemed capital structure, is applied to all network service providers ("NSPs").[104]

United Kingdom: Ofgem states that their objective for the cost of debt benchmark is to *reflect a reasonable debt allowance for the notional efficient operator such that the notional efficient operator is not systematically under- or over-compensated for these reasonable costs*.[105] Moreover, Ofgem states that they *have never set an allowance for debt based on passing through actual debt costs, or allowed costs for particular debt instruments based on verifying their status as 'efficiently incurred'*.[106] Ofgem considers setting a notional cost of debt allowance to be superior to other methodologies.[107] The notional return on debt is designed to track an index reflecting the performance of Pound sterling-denominated investment grade corporate regulated utilities debt.[108] The methodology does not consider different sources of debt as a factor.

The jurisdictional review is summarized in Figure 11.

Figure 11. Summary of the jurisdictional review (treatment of public debt in cost of debt determination)

Jurisdiction	Source of funding
Alberta	The cost of debt is based on actual costs determined by the market, not set by the AUC
Australia	The AER sets the benchmark return on debt using a 10-year simple trailing average of the BBB+ corporate bond yield from third-party providers, which is not based on the source of funding
UK	Ofgem sets the benchmark cost of debt reflecting a notional efficient operator who is not systematically under- or over- compensated for the cost, which does not consider the source of funding

4.1.2.2 Considering ownership type in setting the cost of capital parameters

In jurisdictions reviewed by LEI, utilities' ownership structure is not considered when determining the cost of capital (although this is implicit in the methodologies used, regulators have not made explicit remarks). For example, in Australia and the Netherlands, the regulators

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[104] The AER notes that while they have set *a single benchmark for all regulated businesses*, it is legally permissible to set different ways to calculate the rate of return for gas and electricity if they considered this would better achieve the National Electricity Objective and National Gas Objective, the ultimate objective for AER's decision-making. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

[105] Ofgem. RIIO-2 final determinations – Finance annex (Revised). February 3rd, 2021. Page 181.

[106] Ofgem. RIIO-2 final determinations – Finance annex (Revised). February 3rd, 2021. Page 182.

[107] Ibid.

[108] S&P Dow Jones Indices. Markit iBoxx GBP Regulated Utilities Index Guide. September 2023.

do not explicitly make a distinction based on ownership type despite diversified ownership structures among their regulated entities.

Australia

The AER sets out the way to calculate the rate of return on capital where *the same methodology applies in relation to all regulated services and service providers in calculating the rate of return*, despite diversity in ownership structures among the AER regulated entities.[109] A sample of the AER-regulated utilities and their respective ownership structures are shown in Figure 12 below.

Figure 12. Sample of AER-regulated utilities and their respective ownership structures

Utility	Ownership
ElectraNet	Private
SA Power Networks	Private
AusNet Services	Private
CitiPower	Private
Ausgrid	49.6% owned by the New South Wales government
Endeavour Energy	49.6% owned by the New South Wales government
Essential Energy	100% owned by the New South Wales government
Powerlink Queensland	100% owned by the Queensland government
TasNetworks	100% owned by the Tasmanian government

Sources: AER, utility websites.

Netherlands

The Dutch Authority for Consumers and Markets ("ACM") determines the WACC per activity (e.g., electricity distribution) instead of per company.[110] A sample of the ACM-regulated utilities and their respective ownership structures are shown in Figure 13 below. As such, the ACM does not consider ownership structure when determining the cost of capital.

Figure 13. Sample of ACM-regulated utilities and their respective ownership structures

Utility	Ownership
Nederlandse Aardolie Maatschappij	Private
Eneco	Private
Gasunie	100% owned by the State of the Netherlands
Alliander	100% owned by provincial and municipal governments
Stedingroep	100% owned by municipal governments

Sources: Relevant utility websites.

[109] AER. Rate of return instrument. February 2023. Page.1.

[110] ACM. Decision - WACC annex 2023-2025. October 2022. Page 3.

Relevant Supreme Court decisions affirming a public utility's right to earn a fair return

The Supreme Courts in both the US and Canada have upheld that publicly owned utilities are entitled to a fair return on equity, in the same way that privately owned utilities are entitled to earn a fair return. This will enable utilities to finance their capital investments appropriately.

In Bluefield Waterworks & Improvement Company v. Public Service Commission of the State of West Virginia et al (Bluefield) the US Supreme Court stated: *"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties."*[111]

In British Columbia Electric Railway Company Limited vs. Public Utilities Commission of British Columbia, 1960, SCR, on page 853, the Supreme Court of Canada stated: *"… A public utility which operates in a rapidly expanding community may be required to make substantial expenditures of that nature in order to keep pace with increasing demands. It must, if it is to fulfill those obligations, be able to obtain the necessary capital which is required, which it can only do if it is obtaining a fair rate of return upon its rate base."*[112]

4.1.3 Potential alternatives

With respect to considering the ***source of funding*** in determining the cost of capital parameters, LEI suggests considering two options:

1. **Status quo:** As described in Section 4.1.1, the OEB's current methodology already implicitly considers the impacts of potentially different interest rates based on the source of debt funding in its current methodology.
2. **Uniform/benchmark debt rate for all utilities:** Similar to the UK and Australia examples, the OEB can set benchmark rate(s), incentivizing poor performers from a credit perspective to improve their credit profile (resulting in lower interest rates).

With respect to considering the ***type of ownership*** in determining the cost of capital, LEI considered two options:

1. **Status quo:** As described in Section 4.1.1, the OEB determined in EB-2009-0084 that a utility's ownership structure should not be a relevant factor in determining the cost of capital.
2. **Considering ownership type as a risk factor:** If the OEB believes that the type of ownership significantly changes the risk profile of a utility:

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[111] Butler, Pierce, and Supreme Court of The United States. U.S. Reports: Bluefield Co. v. Pub. Serv. Comm., 262 U.S. 679. 1922. Periodical. Retrieved from the Library of Congress.

[112] Supreme Court of Canada. British Columbia Electric Railway Co. v. Public Utilities Commission. October 4th, 1960.

a. for electricity distributors, the OEB can group the utilities based on risk profiles (with ownership type as one of the key considerations), and determine a slightly different capital structure for each group; and

b. for all other utilities, the OEB may consider ownership type as one of the risk factors in future assessments of capital structure (as part of the rebasing proceedings).

4.1.4 Recommendations

LEI recommends that the OEB maintain its status quo policy regarding the source of funding and the ownership type.

With respect to the ***source of funding***, the difference in loan rates associated with different sources is the only relevant consideration for determining the cost of capital. While deemed debt rates may incentivize management to be efficient in their use of debt, benefits to customers over time are likely minimal. The use of actual costs is empirical and straightforward to consider. Loans realized directly by the government or by its own controlled agency/development bank often have more favorable rates relative to market rates.[113] However, the OEB's existing methodology (described in Section 4.1.1) allows the actual/embedded cost of debt as a pass-through in most cases. As such, if a regulated utility receives relatively favorable debt terms, it is reflected in its rates under the existing methodology. Moreover, LEI has recommended in Section 4.7.2 that the OEB continue to apply DLTDR as a cap (for all utilities, not just electricity distributors).

Further, one of the key principles outlined by LEI in Section 3.1 is that opting for an alternative must yield material benefits which the recommended alternative (uniform/benchmark debt rate for all utilities) does not achieve.

With regards to consideration of ***ownership type***, LEI agrees with the OEB's 2009 report that a utility's ownership structure should not be a relevant consideration in determining its cost of capital parameters. As noted by the OEB, despite differences in ownership structures, all OEB-regulated entities operate as commercial/corporate entities.

The *value conservation principle*, described in the seminal textbook *Principles of Corporate Finance*, states that a company's value is conserved or unchanged when it changes the ownership of claims to its cash flows but does not change the total available cash flows.[114,115] Discounted cash flow ("DCF") valuation is the most fundamental approach to valuing a firm.[116] Under the DCF approach, the value of a company relies on its capacity to generate cash flows from assets in place, the expected growth rate of these cash flows, the timing and pattern of the cash flows and the

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[113] OECD. Infrastructure Financing Instruments and Incentives. 2015. Page 51.

[114] R. Brealey, S. Myers, and F. Allen. Principles of Corporate Finance, 9th ed. New York: McGraw-Hill/Irwin, 2007.

[115] T. Koller, M. Goedhart, and D. Wessels. Valuation: Measuring and Managing the Value of Companies, 6th ed. Wiley, 2015.

[116] NYU Stern. Damodaran on Valuation. Chapter 12: Valuation: Principles and Practice. Accessed on June 5th, 2024.

length of time it will take for the firm to reach stable growth.[117] The ownership structure is irrelevant when assessing a utility's future cash flows.

The regulated utility industry is a relatively low-risk industry given the predictability of cash flows to prudent actors.[118] A regulated utility's financial performance primarily depends on its ability to operate within allowed costs and consistently maximize performance incentives. As such, although the *performance* of the corporatized entity's board/executive team is a relevant factor for investors, the ownership structure should not inherently have any bearing on the ROE allowed by the OEB. And even if a particular ownership structure leads to consistently worse outcomes, it is reasonable for OEB to set a uniform ROE and expect the poor performers to catch up or change their ownership structure.

Allowing uniform ROE regardless of ownership is also consistent with the comparable investment standard of the FRS. The comparable return standard requires the allowed ROE to be *comparable to the return available from the application of invested capital to other enterprises of like risk*. The comparable investment standard implies risk determination based on the utilities' business/investment activities, and not the ownership type.

Rate-regulated entities earn ROE on their regulated asset base ("RAB"). The regulated return to equity and debt investors is based on the value of RAB (the value of "investment" on which the return is made) and the weighted average cost of capital ("WACC"), i.e., the combined rate of return on equity and debt. The operating costs are recouped on a pay-as-you-go basis (with pre-defined performance incentives allowed in advanced regulatory jurisdictions such as Ontario).[119]

As such, regulated utilities within a particular sector face very similar risks, given:

- the composition of their rate bases is similar, i.e., the type of physical assets owned does not vary significantly.[120] As such, electric distributors are commonly grouped as peer utilities when determining the appropriate rate of return; and
- they operate in the same regulatory environment. For instance, all Ontario electric distributors' rates are governed by the same OEB regulations and principles, allowing them equal opportunities to recoup their operating costs.

Allowing some utilities to earn a higher return despite engaging in business activities of similar risk would violate the comparable return standard. As such, LEI believes that as long as utilities

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117 Ibid.

118 S&P Global Ratings classifies regulated utilities as a 'low risk' sector in cyclicality assessment and as 'very low risk' in competitive risk and growth environment assessment, as well as global industry risk assessment. Source: S&P Global Ratings. Updated: January 25th, 2021.

119 Organisation for Economic Co-operation and Development ("OECD"). The International Transport Forum. The Regulatory Asset Base and Project Finance Models. February 2016.

120 The proportion of assets (such as underground and overhead lines) may vary based on individual distributor characteristics such as geography, but the type of assets in electricity distributors' rate bases are similar.

undertake business/investment activities of similar (or like) risk, the ownership type/structure should not matter.

LEI recommends that the OEB continue with the status quo as the alternative does not meet the FRS (which is a legal requirement, as highlighted in the guiding principles described in Section 3.1) and the general principles of corporate finance and valuation.

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- The OEB's existing methodology implicitly accounts for differences in sources of funding when approving rate applications. LEI recommends that this aspect of the OEB methodology should be retained.
- Consistent with the OEB's existing policy, the approach to setting the cost of capital parameters and capital structure should not depend on a utility's ownership structure. LEI believes the status quo is consistent with the FRS and Canadian Supreme Court judgement(s).

4.2 General issues – risk factors to be considered in determining the cost of capital parameters and capital structure

Issue 2: ***What risk factors*** (including, but not limited to, energy transition) ***should be considered***, and ***how should these risk factors*** under the current and forecasted macroeconomic conditions ***be considered in determining the cost of capital parameters and capital structure***?

The two key risk factors that need to be considered when determining the cost of capital parameters and capital structure are (i) business risks and (ii) financial risks. While energy transition risk has been specifically mentioned in Issue 2, one can reasonably argue that it is part of business risk, which can ultimately impact the bottom line (i.e., leading to a change in financial risks/returns).[121]

Business risks and financial risks are related to uncertainty surrounding a company's operating earnings and its ability to finance its investments. For example, the AUC defines business risk as follows: *Business risk represents the perceived uncertainty in future operating earnings before the impact of financial leverage (EBIT) and, hence, determines the capacity for a business to be financed with debt as opposed to equity.*[122] Separately, financial risks are primarily linked to a company's ability to continue to finance its capital needs and growth opportunities by attracting investors at reasonable terms.

[121] Credit rating agencies (such as S&P Global Ratings and DBRS Morningstar) also consider energy transition risk as part of business risks, which may ultimately impact financial risks/returns, when assessing ratings for regulated entities. Sources: S&P Global Ratings. Sector-Specific Corporate Methodology. April 4th, 2024. Page 147; DBRS Morningstar. Risks of the Green Energy Transition for U.S. Regulated Electric Utilities. May 21st, 2021.

[122] AUC. Decision 20622-D01-2016 - 2016 Generic Cost of Capital. October 7th, 2016. Page 115.

The riskier the investment's cash flows, the greater its cost of capital.[123] The risk factors can broadly be categorized as un-diversifiable (or unavoidable) risks inherent in the market (sometimes referred to as systematic risks) and company/asset-specific risks (sometimes referred to as unsystematic risks). Regulators typically adjust the cost of capital parameters and capital structure in response to changes in systematic risks. Examples of systematic risks include macroeconomic risk factors such as interest rates, inflation and recessions, regulatory risk, and policy risk.

4.2.1 Status quo

The OEB sets a uniform ROE for all regulated entities. However, per its stated policy, it undertakes a full reassessment of a utility's capital structure in the event of significant changes in the company's business and/or financial risk.[124]

As such, the OEB typically assesses the major risk factors following a utility's application for a change in equity thickness. The most recent assessments for electricity distributors were performed in 2006 (2006 report), Enbridge Gas in 2023 (EB-2022-0200), and OPG in 2017 (EB-2016-0152).[125]

Macroeconomic risk factors such as higher interest rates are not explicitly considered in these proceedings because they are intended to be embedded in the allowed ROE, DLTDR, and DSTDR. Further, utilities' ability to manage inflation depends on the design of IR mechanisms and hence, can be discussed as part of regulatory risk.

The aforementioned proceedings considered risks that can be grouped into the following business risk factors:

1. **Energy transition risk** refers to the shift from an energy system that primarily relies on fossil fuel-based energy sources (such as natural gas, coal and oil) to net zero-emitting renewable energy sources (such as batteries, solar and wind power, and carbon capture and storage). Notably, OEB's 2023 decision for Enbridge Gas considered energy transition risk to be one of the key reasons for an increase in business risk since the legacy utility rates were last rebased in proceedings initiated in 2011.[126]
2. **Volumetric risk** refers to the uncertainty in demand and consumer additions over the forecasting period, which may increase the likelihood of a forecasting error. A significant

[123] CFA Institute. Cost of capital. Accessed on April 29th, 2024.

[124] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

[125] Although the OEB policy states that they assess the capital structure for electricity transmitters on a case-by-case basis, the OEB currently allows an equity ratio of 40% (same as electricity distributors) to electricity transmitters. To the best of LEI's knowledge, the OEB has not separately assessed the risk factors for electricity transmitters.

[126] OEB. EB-2022-0200. Decision and Order. December 21st, 2023. Page 67.

forecasting error (if beyond the scope of relevant DVAs available to utilities) may lead to a material under-recovery or over-recovery of revenue.

3. **Operational risk** refers to the uncertainties and hazards a company faces when it pursues its day-to-day business activities.[127] Examples of operational risk factors include the degradation of aging nuclear power station components (OPG), impacts of meteorological/geological events on gas pipeline infrastructure (Enbridge Gas), and the geographic size and isolation of the distributor's service area (electricity distributors). In 2014, the OEB considered the addition of 48 hydroelectric facilities to OPG's rate base since OEB's previous review to have reduced the business risk for OPG as the share of hydroelectric assets in the rate base increased (OEB considered hydroelectric facilities to be lower risk than nuclear facilities).[128]

4. **Regulatory risk** refers to the impacts of OEB policies/regulatory mechanisms. For instance, in addition to the reduction of operational risk described above, the OEB also considered the addition of several DVAs since its last review (particularly the addition of a new pension variance account) to have reduced business risks for OPG. In 2017, the transition to incentive-based rates was considered a factor increasing OPG's business risks in its rate application, however, the OEB did not accept this argument.[129]

5. **Policy risk** refers to the impacts of Ontario, federal or municipal government policies/legislations. For instance, introducing the federal carbon price was considered to increase Enbridge Gas' risk by making alternative heating technologies more attractive. Policy risk can also increase when rates increase significantly in a short period of time, typically within 1-2 years (such as when higher natural gas prices in 2022 lead to dramatic increases in electric and gas distribution rates in many jurisdictions), triggering affordability concerns for customers. In such scenarios, the risk of rate freezes is higher.

The assessment of <u>financial risks</u> has focused on the utility's ability to continue to attract debt and equity financing at reasonable terms. A widely followed approach to evaluating financial risk is to assess key credit metrics and their potential impact on credit ratings. S&P Global Ratings ("S&P Global") and DBRS Morningstar ("DBRS") rely on several key credit metrics, such as: (i) Debt/EBITDA, (ii) Funds from Operations ("FFO")/Debt, (iii) FFO/Interest, (iv) Cashflow from Operations ("CFO")/Debt, and (v) EBIT/Interest.[130,131] Figure 14 provides a brief description of these metrics.

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[127] Investopedia. Operational Risk Overview, Importance, and Examples. Updated; January 16th, 2023.

[128] OEB. EB-2013-0321. Decision with Reasons. November 20th, 2014. Pages 112-115.

[129] OEB. EB-2016-0152. Decision and Order. December 28th, 2017. Page 101.

[130] S&P Global Ratings. *Corporate Methodology: Ratios And Adjustments.* November 19, 2013.

[131] DBRS Morningstar. *Methodology. Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry.* September 2019

Figure 14. Description of key credit metrics (not exhaustive)

Credit metric	Description
Debt/EBITDA	▪ Evaluates a company's ability to pay its debts ▪ A higher value suggests a longer time may be needed to pay debt, and thus is correlated with lower credit rating
FFO/Debt	▪ Assesses extent to which company is leveraged ▪ A lower value suggests higher leverage levels, and is correlated with lower credit rating
FFO/Interest	▪ Assesses the ability of a company to service its interest expenses ▪ A higher value suggests sufficient cashflows to service interest payments, and may support higher credit rating
CFO/Debt	▪ Assesses the leverage but evaluates the extent to which the company's operating cashflows can repay its debt obligations ▪ Like FFO/Debt, a lower value is correlated with a lower credit rating
EBIT/Interest	▪ Measures a company's earnings over its interest payments. ▪ A higher value suggests better financial health of the firm, and correlates to a higher credit rating

Notes: Key terms defined as follows:

"Debt" defined as total debt, including long-term and short-term borrowing.

Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") defined as revenues minus operating expenses (excluding depreciation, amortization, and non-current asset impairment and impairment reversals).

Funds from operations ("FFO") represents a company's ability to generate recurring cash flows from operations (S&P Ratings defines it as EBITDA minus cash interest paid minus cash taxes paid).

"Interest" defined as total interest expense.

Cash from operations ("CFO") is also referred to as operating cash flow. This measure takes reported cash flows from operating activities (as opposed to investing and financing activities).

4.2.2 Relevant jurisdictional review

In this section, LEI has reviewed the risk factors considered in Alberta, Australia and British Columbia. These risk factors can largely be grouped into the existing risk categories considered by the OEB in recent assessments.

Alberta:

The AUC, in its October 2023 decision associated with *the Determination of Cost-of-Capital Parameters in 2024 and Beyond*, identified three major risk factors as described below:

1) **Macroeconomic factors**: The AUC acknowledged that increasing interest rates and inflation since 2018 resulted in higher capital costs. However, it did not consider these factors to lead to higher approved ROEs or deemed equity thickness. Utilities in Alberta are *largely isolated from broader macroeconomic factors* because of certain regulations such as performance-based ratemaking ("PBR") for distribution utilities and cost-of-service ("COS") regulation for transmission utilities. The AUC stated that regulations provide utilities a reasonable opportunity to recover costs, including those directly and indirectly

affected by interest rates and inflation. PBR plans for distributors include inflation as a direct input into the PBR formula while COS regulation affords transmitters *a reasonable opportunity to recover all reasonable forecast cost increases related to the safe, reliable and efficient provision of services to customers over the future test period*;[132]

2) **Regulatory risk**: The utilities claimed that regulatory risks in Alberta have increased since 2018. The identified risks included lower deemed equity thickness and lower approved ROEs than those awarded in other North American jurisdictions, regulatory lag, stranded asset risk, and a decline in rating agency perceptions of the Alberta regulatory regime from *most credit supportive* to *highly credit supportive*. However, the AUC did not consider the claims to be valid adding *Alberta utilities have low earnings volatility, low business risk ratings and, operate within a regulatory framework that encourages and rewards utility-driven initiatives, projects, and investments in cost reduction and efficiency improvement that can lead to earnings in excess of approved ROEs*;[133] and

3) **Decarbonization**: The utilities argued that carbon reduction goals are generally more aggressive and difficult in Alberta than decarbonization policies in other jurisdictions. However, the AUC concluded that the utilities provided little or no evidence to indicate that they have experienced *any significant increase in risk related to customers changing behavior, a reduction in natural gas demand, complications related to electrification, or factors that might impact their operations*.[134]

Australia

The AER, in its February 2023 *Rate of Return Instrument* identified three major risk factors as described below[135]:

1) **Demand risk**: The demand risk refers to the forecast error in demand. The AER considers the revenue or price-setting mechanism to mitigate the risk. Under a price cap, NSPs can mitigate the risk by restructuring tariffs through higher fixed charges set to offset decreasing demand. Under a revenue cap, NSPs can mitigate the risk through price adjustments in subsequent years;

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[132] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 58.

[133] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 59.

[134] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 60.

[135] AER. Rate of return instrument. Explanatory statement. February 2023.

2) **Inflation risk**: The AER finds that regulated NSPs face less inflation risk than unregulated entities, since fluctuations in inflation are reflected in CPI-X, where CPI is the Consumer Price Index, and X is the pricing adjustment mechanism;[136] and

3) **Interest rate risk**: Movements in the interest rate affect the financing costs of customers. The AER states that the regulatory framework effectively reduces the risk. It notes that *the rate of return derived in 2022 is higher than that derived in 2018 because underlying market interest rates have risen in recent years*.[137] Moreover, the AER acknowledges concerns regarding the sufficiency of the ROE during a low-interest rate period, and published a paper[138] that considered the potential consequences of low-interest rates, and investigated the need to adjust the approach to the rate of return. The paper finds that the overall rate of return achieved under the current regulatory framework during the low-interest rate period was sufficient.

British Columbia

The British Columbia Utilities Commission ("BCUC"), in its September 2023 decision associated with the *Generic Cost of Capital Proceeding (Stage 1)*, identified seven major risk factors as described below[139]:

1) **Economic conditions**: FortisBC claimed that 'economic condition risk' has increased significantly due to inflation.[140] The BCUC disagreed with the assessment and finds the risk has remained unchanged since 2016 (for FEI) and 2013 (for FBC)[141]. It added that the risk does not affect FortisBC's ability to access capital or impact cash flow from customers since its O&M expenditures and growth capital are indexed into a composite inflation factor and are recoverable from ratepayers;

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136 The CPI number is actual CPI measured by the Australian Bureau of Statistics, and the x factor represents the rate of change in required revenue (in real dollars) each year to recover costs over the regulatory period. For both electricity distribution and transmission, the CPI-X methodology is used to index the allowed revenue. For electricity distributor, the control mechanism or some incentive-based variant for standard control services must be of the prospective CPI minus X form; for electricity transmitters, the CPI-X is applied in escalating the maximum allowed revenue for the provider for each regulatory year of a control period. For gas utilities, the National Gas Rules ("NGR") is less prescriptive regarding inflation and does not explicitly state how the capital base is to be indexed. Source: AER. Final position. Regulatory treatment of inflation. December 2020.

137 AER. Rate of return instrument. Explanatory statement. February 2023. Page 9.

138 AER. Term of the rate of return & Rate of return and cashflows in a low interest rate environment – Final working paper. September 2021.

139 BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

140 FortisBC is the collective name of FortisBC Energy Inc. ("FEI") and FortisBC Inc. ("FBC"), which are the benchmark utility for natural gas utilities and electricity utilities, respectively.

141 The BCUC published the most recent proceeding in 2023 and the previous proceeding for natural gas utilities in 2016 and for electricity utilities in 2013.

2) **Political risk**: FEI noted that the energy transition risk is apparent in BC's CleanBC Roadmap to 2030 ("Roadmap"), which sets out a greenhouse gas reduction obligation for natural gas utilities. The BCUC agreed with FEI and noted that the energy transition poses uncertainty regarding the role that BC's natural gas utilities will play and that there is *a growing bias against the use of natural gas on the part of multiple policymakers*.[142] The BCUC found the political risks for natural gas utilities have increased significantly since 2016. The BCUC agreed with FBC that the political risk is lower for electricity utilities adding that *the Energy Transition that limits on the future growth prospects of FEI is mirrored in expanded FBC growth prospects*[143];

3) **Indigenous rights and engagement risk**: The risk refers to the potential for utility operations to be impacted by policy or legislation regarding *Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title*.[144] Utilities with operations in areas not covered by treaty, meaning the land is unceded, may be subject to legal claims for title in the future. FortisBC assessed the risk as higher compared to that in 2016/ 2013. The BCUC agreed with the conclusion but could not determine the accurate magnitude of the difference. BCUC noted that although costs associated with the risk are recoverable through rates and hence are typically a ratepayer risk, there is a perceived risk by investors since *FortisBC's commitment to developing meaningful relationships with Indigenous communities cannot fully mitigate investors' perception of Indigenous risk*[145];

4) **Energy price risk**: Energy prices impact a utility's business risk as prices can influence consumer energy choices. FEI claimed the energy price risk is higher than that in 2016 partially because of volatility in natural gas prices, the increased weather events, forecasted LNG demand growth, and forecasted decrease in oil production. The BCUC agreed with FEI and noted that ratepayers largely bear the increase in energy price risk. However, the BCUC considers that government policies encouraging decarbonization may diminish natural gas' relative price advantage over electricity, therefore increasing perceived risk among investors, which could impact investors' expected return;

5) **Demand/market risk**: FEI stated that the worsening of customers' perception of natural gas and the development of new electric technologies could decrease demand for natural gas. While the BCUC did not consider declining market share necessarily represented declining revenues or an inability for utilities to achieve allowed ROEs, the BCUC considered *the declining market share would be perceived negatively by investors thereby affecting the shareholders' expected returns*[146];

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[142] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. Page 36.

[143] Ibid. Page 54.

[144] Ibid. Page 36.

[145] Ibid. Page 38.

[146] Ibid. Page 49.

6) **Operating risk**: FortisBC submitted operating risks such as asset concentration, technologies employed to deliver service, service area geography, human error, weather, public attitudes towards the fossil-fuel industry, and cybersecurity have increased compared to that in 2016/2013, but the BCUC found that the operating risk remained unchanged as no evidence was provided to indicate otherwise; and

7) **Regulatory risk**: FortisBC noted that there is an increase in overall regulatory risk, adding that *regulatory uncertainty gives rise to the risk that the allowed return on rates may not meet the [FRS], or that necessary investments are not approved*. It also claimed that risk associated with regulatory lag and ultimate approval of cost recovery also increased since 2016/2013 caused by increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title. However, the BCUC decided that it was not persuaded by the submitted evidence and found that FortisBC's regulatory risk remained unchanged since 2016/2013.

The summary of the jurisdictional analysis is shown in Figure 15 below.

Figure 15. Summary of the jurisdictional review (risk factors considered by regulators)

Jurisdiction	Risk factor
Alberta	• **Macroeconomic factors**: Utilities are largely isolated from broader macroeconomic factors • **Regulatory risk**: Utilities operate within a supportive regulatory framework of low regulatory risk • **Decarbonization**: Utilities provided little or no evidence to indicate that they have experienced any significant increase in risk related to decarbonization
Australia	• **Demand risk**: NSPs mitigate the risk through the revenue or price-setting mechanism • **Inflation risk**: Regulated NSPs face less inflation risk than unregulated NSPs • **Interest rate risk**: The current regulatory framework effectively reduces the interest rate risk
British Columbia	• **Economic conditions**: The economic condition risk has remained unchanged for FEI and FBC since 2016 and does not impact their ability to access capital or affect cash flow from customers • **Political risk**: The political risk has increased significantly for FEI (and other gas utilities) and decreased for FBC (and other electric utilities) due to Energy Transition • **Indigenous rights and engagement risk**: Utilities with operations in areas not covered by treaty may be subject to legal claims for title in the future • **Energy price risk**: FEI faces higher risk than that in 2016 which may be offset by policies encouraging decarbonization • **Demand/market risk**: Customers' worsened perception of natural gas and the development of new electric technologies could decrease demand for natural gas, which would be perceived negatively by investors thereby affecting investors' expected return • **Operating risk**: The operating risk has remained unchanged for FEI and FBC since 2016 as no evidence suggests otherwise • **Regulatory risk**: The regulatory risk has remained unchanged for FEI and FBC since 2016

4.2.3 Potential alternatives

In addition to the business risks and financial risks considered by the OEB in recent applications (see Section 4.2.1), the OEB can review additional risk factors considered in other jurisdictions, such as explicitly considering macroeconomic risk factors (inflation, interest rates, etc.), and energy/commodity price risk. One may argue that these risks are subsumed under existing risk categories. Major macroeconomic risk factors and energy price risk (which LEI views as "affordability risk") ultimately relate to regulatory risk, i.e., the availability of appropriate regulatory mechanisms to mitigate such risks. Examples include the composition of the I factor to mitigate inflation risk, allowed ROE/DLTDR to mitigate interest rate risk, and variance accounts to mitigate the energy price volatility risk.

With respect to alternate ways of how to consider risk factors, the OEB may adopt one of the three options below:

1. **Status quo:** As described in Section 4.2.1, the OEB currently undertakes a full reassessment of a utility's capital structure in the event of significant changes in the company's business and/or financial risk.
2. **Consider the risk factors at defined intervals (for adjusting the capital structure):** The OEB can set a pre-defined interval (e.g., 1, 3 or 5 years) to assess material changes in business and financial risks and determine their impacts (if any) on the capital structure allowed to utilities.
3. **Consider the risk factors at defined intervals (for adjusting the ROE):** Alternatively, the OEB can set a pre-defined interval (e.g., 1, 3, or 5 years) to assess material changes in business and financial risks and consider the impacts (if any) as an additional component in the ROE formula that adds to/subtracts from the ROE. However, this would also entail moving away from determining a single uniform ROE for all utilities.

4.2.4 Recommendations

The major risk factors considered in other jurisdictions are similar to the ones considered in OEB proceedings. They can be grouped under the risk factors assessed by the OEB in recent equity thickness applications. LEI believes that the review of existing risk factors listed in Section 4.2.1, considering the current and forecasted macroeconomic conditions, are sufficient to determine the cost of capital parameters and capital structure (however, LEI believes that energy transition risk is primarily a policy risk and may be grouped as such). The key business risk factors include volumetric risk, operational risk, regulatory risk and policy risk (including energy transition risk). Financial risk assessment may be focused 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 (based on scenario analysis modelling for future utility cash flows). Financial risk assessment also includes the utility's debt servicing ability, as well as financial integrity. The key credit metrics that the OEB can consider are described in Figure 14.

Furthermore, as the OEB highlights in its capital structure policy, most risk factors tend to be stable over time. As such, considering their impacts at pre-defined intervals (as described in

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.

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- 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 discussed selected case studies where regulators in other jurisdictions responded to changes in regulatory mechanisms.

As the OEB has reviewed the risks for natural gas distribution and regulated generation (Enbridge Gas in 2023 and OPG in 2017) in recent applications, LEI has primarily focused on electricity distribution and transmission sectors.[147] However, LEI has also highlighted some of the key regulatory risks considered for Enbridge Gas and OPG in recent applications.

4.3.1 Status quo

The OEB typically considers regulatory risks as part of the overall risk assessment associated with reviewing appropriate equity thickness for regulated utilities. The review is performed upon application by the utility or other participants during rate proceedings.

LEI performed a comprehensive scan of the major OEB regulatory/policy changes enacted since 2006. None are arbitrary, all involved significant consultation, and each was known to industry long before implementation. To shortlist the relevant policies, LEI has considered the policies that are currently in effect and have the potential to impact future utility cash flows materially. Accordingly, LEI has considered the following:

1. Electricity distributors' DVA review initiative (EB-2008-0046; OEB report issued in July 2009);[148]
2. Renewed regulatory framework for electricity (EB-2010-0377, EB-2010-0378 and EB-2010-0379; OEB report issued in October 2012);[149]
3. Rate design for electricity distributors (EB-2012-0410; OEB report issued in April 2015);[150]
4. Rate design for commercial and industrial customers (EB-2015-0043; OEB Staff report issued in February 2019);[151] and
5. Framework for energy innovation: distributed resources and utility incentives (EB-2021-0118; OEB report issued in January 2023).[152]

While each of these represented new policies, in almost all cases the impact was to either reduce uncertainty, increase flexibility, or provide compensation for changes in risks.

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[147] Although the OEB did not perform a detailed risk assessment for OPG in EB-2020-0290, the parties involved in the proceeding agreed to retain OPG's existing capital structure in the settlement agreement. Source: OEB. EB-2020-0290. Decision and Order. November 15th, 2021.

[148] OEB. Review of Electricity Deferral and Variance Account Balances. Accessed on May 6th, 2009.

[149] OEB. Renewed Regulatory Framework for Electricity. Accessed on May 2nd, 2024.

[150] OEB. Rate Design for Electricity Distributors (formerly Revenue Decoupling for Distributors). Accessed on May 2nd, 2024.

[151] OEB. Rate Design for Commercial and Industrial Customers. Accessed on May 2nd, 2024.

[152] OEB. Framework for Energy Innovation: Distributed Resources and Utility Incentives. Accessed on May 2nd, 2024.

Electricity distributors' DVA review initiative

The OEB is required under Section 78 of the Ontario Energy Board Act, 1998 to review the electricity distributor's DVAs periodically.[153] DVAs are commonly used regulatory tools that allow a utility an opportunity to address costs that were unknown or uncertain when its rates were set.[154] A deferral account tracks the cost of a project or program that the utility could not forecast when its current rates were set. When the costs are known, the utility can request OEB approval to recover the costs in future rates. A variance account tracks the difference between the forecast cost of a project or program, which has been included in rates, and the actual cost. If the actual cost is lower (or higher), the utility may request OEB approval to return the difference to customers as a credit (or to recover the difference through rates).[155]

In July 2009 (EB-2008-0046), the OEB issued a report to update its processes for reviewing electricity distributors' DVAs.[156] Among other things, the report classified the accounts into two groups (Group 1 and Group 2) based on the required depth of the OEB's review and the process by which the account balances would be reviewed.

Group 1 included accounts that do not require a prudence review, i.e., account balances that are cost pass-through. These accounts are reviewed annually when a certain threshold is met in the utilities' Incentive Rate Proceedings. Processes outlined in the OEB's guidelines for review of electricity DVAs (September 2005) were to continue for Group 2 accounts. At the time of rebasing, all Group 1 and Group 2 account balances are to be reviewed.

Notably, the OEB did not propose any changes to its DVA carrying charges policy/methodology. As such, although the OEB has approved additional DVA accounts for electricity distributors since it approved the 60-40 debt-equity ratio in 2006, the overarching OEB policy for DVAs has not changed materially since 2006. However, the OEB has established several new DVAs since 2006.

For utilities other than electricity distributors, the OEB generally considers DVAs on a case by case basis.[157] The OEB has established several DVAs since 2006 arising from the policy needs, including:

1) **Customer Choice Initiative deferral account**: The account was established in September 2020 in response to the OEB's Standard Supply Service Code ("SSSC"). The SSSC enables electricity customers on the Regulated Price Plan to switch from time-of-use prices to

[153] OEB. Review of Electricity Deferral and Variance Account Balances. Accessed on May 6th, 2009.

[154] OEB. Backgrounder. Ontario Energy Board issues decision on Ontario Power Generation accounting order application. June 27th, 2023.

[155] Ibid.

[156] OEB. EB-2008-0046. Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR). July 31st, 2009.

[157] Hydro One has 16 DVAs related to transmission (as filed in EB-2019-0082), and Enbridge Gas and OPG have between 30 and 40 DVAs (as filed in EB-2022-0200 and EB-2020-0290 for Enbridge Gas and OPG respectively).

tiered pricing. The generic account records distributors' costs associated with implementing the customer choice initiative;[158]

2) **Broadband deferral account**: The account was established in July 2022 to record impacts pertaining to *Ontario Regulation 410/22* (Electricity Infrastructure – Designated Broadband Projects). The regulation requires all rate-regulated distributors to establish a deferral account to record incremental costs associated with activities pertaining to designated broadband projects;[159]

3) **Getting Ontario Connected Act ("GOCA") variance account**: The account was established in October 2023 for the purpose of tracking incremental costs of locates in 2023 and onwards arising from the implementation of *Bill 93* (the *Getting Ontario Connected Act, 2022*). *Bill 93* imposes a five-business-day deadline on large utilities[160] for *completing standard locate requests and introducing administrative penalties for failing to comply;*[161]

4) **Low-income Energy Assistance Program Emergency Financial Assistance ("LEAP EFA") deferral account**: The OEB established two deferral accounts in February 2024, allowing rate-regulated electricity and gas distributors to record LEAP EFA contributions exceeding the funding amounts[162] embedded in rates;[163] and

5) **Cloud Computing deferral account**: This was established to record incremental operating and capital expenses related to cloud computing (discussed further in Section 4.22).

Renewed regulatory framework for electricity ("RRFE")

The RRFE focused on reforming the regulatory framework concerning three policies:[164]

1. **Rate-setting:** the OEB introduced three IR mechanisms for the utilities to choose from:

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158 OEB. OEB File No. EB-2020-0152. Letter re: Accounting Order for the establishment of a deferral account to record impacts arising from implementing the customer choice initiative. September 16th, 2020.

159 OEB. Letter re: Accounting Order (001-2022) for the establishment of a deferral account to record impacts pertaining to Ontario Regulation 410/22 (Electricity Infrastructure – Designated Broadband Projects). July 7th, 2022.

160 Large utilities are Alectra Utilities Corp., Elexicon Energy Inc., Enbridge Gas Inc., Hydro One, Hydro Ottawa Ltd., Oakville Hydro Electricity Distribution Inc., and Toronto Hydro-Electric System Ltd. Source: OEB. Decision and Order EB-2023-0143. Getting Ontario Connected Act Variance Account. October 31st, 2023.

161 OEB. Decision and Order EB-2023-0143. Getting Ontario Connected Act Variance Account. October 31st, 2023. Page 2.

162 Under the generic funding mechanism, *each distributor provides the greater of 0.12% of their total OEB-approved distribution revenue requirement or $2,000 each year for LEAP EFA*. Source: OEB. OEB File No. EB-2023-0135. Letter re: Changes to the Low-income Energy Assistance Program Emergency Financial Assistance and Accounting Orders. February 12th, 2024. Page 3.

163 OEB. OEB File No. EB-2023-0135. Letter re: Changes to the Low-income Energy Assistance Program Emergency Financial Assistance and Accounting Orders. February 12th, 2024.

164 OEB. Report of the Board. Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. October 18th, 2012.

a. **4th generation IR or price cap IR:** Under this method, rates are set on a single forward test year on a cost of service basis, and subsequently indexed by the price cap index formula for the four remaining years. The OEB considered the approach to be suitable for most electricity distributors with incremental capital investment needs.

b. **Custom IR:** Under this method, rates are set based on a five-year forecast of revenue requirement and sales volumes, however the OEB provided flexibility to utilities opting for this approach to propose specifics of the formula in individual rate applications. The OEB considered this approach to be most suitable for utilities with significantly large multi-year or highly variable investment commitments that exceed historical levels.

c. **Annual IR index:** The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. There is no forecast cost of service review using this method, and existing rates are adjusted using a simple price cap index formula. The OEB did not find it necessary to establish a fixed term under this method, and a utility whose rates have been set utilizing this approach may apply to have its rates rebased and set under a different method at any time. The OEB considered this method to be suitable for utilities with steady-state operations and limited incremental capital requirements.

Electricity distributors can choose any of the three IR options; electricity transmitters can choose custom IR or revenue cap IR. Gas utilities can choose price cap IR or custom IR, and OPG must use price cap IR.[165] OEB considered the move to IRM from cost of service regulation to have reduced risks for OPG (see text box below). The summary of differences between the three approaches is provided in Figure 16. Prior to RRFE, the 3rd generation IR included a single option for utilities and was similar in methodology to the existing price cap IR.

The move to IRM from cost of service regulation for hydroelectric payments for OPG

The move to IRM was one of the key issues claimed by OPG in EB-2016-0152 to have increased their business risks. The OEB stated that there is no evidence that the hydroelectric IRM will have any impact on risk. It added that there are protections from forecast risk concerning costs and hydroelectric production provided by the Hydroelectric Water Conditions Variance Account and the Capacity Refurbishment Variance Account for significant capital spending on hydroelectric projects. It also highlighted that there are other mechanisms under a Price Cap IR plan, such as those approved by the OEB in EB-2016-0152, including Z-factors and Incremental Capital Module ("ICM"), as proposed by OPG. Given these protections, the OEB concluded that it did not consider the move to IRM to pose much uncertainty for OPG.

[165] OEB. Handbook for Utility Rate Applications. October 13th, 2016.

2. **Planning:** Distributors are required to file 5-year capital plans to support their rate applications. Planning is integrated to pace and prioritize capital expenditures, including smart grid investments.

3. **Measuring Performance:** The OEB proposed developing standards and measures that link directly to the performance outcomes. Using a scorecard approach, distributors are required to report annually on their key performance outcomes. As of April 2024, the OEB publishes 20 performance measures (updated annually) in areas related to customer focus, operational effectiveness, public policy and responsiveness, and financial performance.[166] However, the performance targets set by OEB are not yet linked to financial incentives and penalties for the distributors.

Figure 16. Comparison of three IR mechanisms provided by OEB

Setting of Rates	Price Cap IR	Custom IR	Annual IR Index
"Going-in" Rates	Determined in a single forward Test-year cost of service review	Determined in a multiyear application review	No COS review, existing rates Adjusted by the Annual Adjustment Mechanism
Form	Price Cap Index	Custom Index	Price Cap Index
Coverage	Comprehensive (i.e. Capital and OM&A)		
Annual Adjustment Mechanism – Inflation	Composite Index	Utility-specific rate trend for the plan term to be determined by the Board based on: (1) the forecast (revenue and costs, inflation, Productivity); (2) the inflation and productivity analyses; and (3) bench-marking to assess the reasonableness of the forecasts	Composite Index
Annual Adjustment Mechanism – Productivity	Peer Group X – factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on Price Cap IR-X-factors
Role of Benchmarking	To assess reasonableness of cost forecasts and to assign stretch factors		N/A
Sharing of Benefits	Productivity Factor		
	Stretch factor	Case-by-case	Highest Price Cap IR stretch factor
Term	5 years (rebasing plus 4 years)	Minimum term of 5 years	No fixed term
Z factors	Same as in the 3rd generation incentive regulation		
Performance Reporting & Monitoring	A regulatory review may be initiated if annual reports show performance outside of the +/- 300 basis point earnings dead band or if performance erodes to unacceptable levels		
Appropriate for	Utilities that anticipate some incremental investment needs will arise during the plan term	Utilities with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures	Utilities with relatively steady state investment needs

Source: OEB. Report of the Board. Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. October 18th, 2012. Page 13.

166 OEB. What are electricity utility scorecards? Accessed on May 2nd, 2024.

As shown in Figure 16 above, utilities can also utilize an off-ramp mechanism, which triggers a regulatory review if earnings fall outside a deadband of +/- 300 bps from the approved ROE.[167]

Rate design for electricity distributors (residential customers)

Per the OEB policy in 2015, electricity distributors were directed to structure residential rates such that all costs for residential distribution service are collected through a fixed monthly charge.[168] This policy was focused on one aspect of electricity charges: distribution rates or delivery charges. Distribution rates are designed to recover costs such as poles, wires, meters, transformer stations, trucks and computer systems that bring electricity from the high-voltage transmission system to Ontario's individual homes and businesses through lower-voltage distribution lines. The OEB estimated at the time that these charges represented about 20% to 25% of a residential customer's total electricity bill. The other parts of the electricity bill relate to charges for electricity generation, transmission, and system operations.[169]

A distributor's costs are largely comprised of fixed costs, i.e., they do not vary significantly based on higher or lower amounts of electricity flowing through the distribution lines. As such, it made sense to shift to revenue collection from fixed monthly charges. The transition to fixed charges was implemented gradually and was *nearly complete* by 2019.[170] Residential customers accounted for about 36% of the total demand in Ontario in 2022. Although the new rate design is designed to be revenue neutral, it is intended to increase certainty in cost recovery for distributors. As such, the change in rate design is intended to reduce volumetric risk for electricity distributors.

Rate design for commercial and industrial electricity customers

In 2019, OEB staff proposed shifting from a 2-tier rate design (fixed and variable/energy charges) to a 3-tier rate design (customer, demand, and energy charges) for most commercial and industrial electricity customers.[171] Customer and demand-related costs are the primary drivers of distribution system costs. Notably, although commercial and industrial electricity customers make up ~10% of the total customer base in Ontario, they accounted for 54% of the total demand in 2022. OEB staff also proposed an additional capacity reserve charge for larger commercial and industrial customers (peak demand >= 50 kW) to ensure that they continue to pay for capacity maintained in the system to serve them.[172]

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[167] OEB. *Filing Requirements For Electricity Distribution Rate Applications – 2021 Edition for 2022 Rate Applications (Chapter 3: Incentive Rate-Setting Applications).* June 24, 2021.

[168] OEB. EB-2012-0410. Board Policy. A New Distribution Rate Design for Residential Electricity Customers. April 2nd, 2015.

[169] Ibid.

[170] OEB. EB-2015-0043. Staff Report. Rate Design for Commercial and Industrial Electricity Customers. February 21st, 2019. Page 3.

[171] Ibid.

[172] Ibid.

A customer charge (or fixed charge) is intended to recover customer-related costs, including a portion of minimum system costs. Demand charges are based on peak power usage rather than overall energy consumption.[173] Peak power usage rather than overall consumption largely drives investments in distribution infrastructure. However, the prior rate design did not account for the customer load shape in its design. As such, the proposed rate design is intended to better reflect the investment needs of electricity distributors.

In the text box below, LEI has highlighted an example of a change in Enbridge Gas' rate design leading to potentially lower business risks.

Enbridge Gas' move to straight fixed variable with demand ("SFVD") rate design was proposed in EB-2022-0200 to reduce risk

The proposed SFVD rate design included a separate customer charge (based on Enbridge Gas' fixed costs), and a demand charge (based on Enbridge Gas' variable costs). Enbridge Gas proposed that relative to the current rate design, the delivery charge under SFVD more accurately matches the cost recovery with the cost of the customer connection to the distribution system and the demand each customer imposes on the system. The capital structure experts retained by OEB staff and Enbridge Gas agreed that, if approved, it would reduce the volumetric risk for Enbridge Gas.

Framework for energy innovation: distributed resources and utility incentives

The OEB initiated the Framework for Energy Innovation ("FEI") consultation in March 2021 *to clarify the regulatory treatment of innovative and cost-effective solutions, including distributed energy resources (DERs), and facilitate their adoption in ways that enhance value for consumers*.[174] In January 2023, the OEB set out its policies and next steps with respect to the integration of DERs into distribution system planning and operations, as well as the use of DERs by electricity distributors as non-wires alternatives ("NWAs").[175]

In the January 2023 report, the OEB laid out the timeline of next steps for electricity distributors:

1. ***OEB expectations of electricity distributors***: distributors are expected to modify their planning and operations to prepare for DER impacts on their systems, including integrating these resources cost-effectively while maintaining reliable service for their customers. Distributors are also expected to consider DER solutions as NWAs when assessing options for meeting system needs.

2. ***Benefit-cost analysis ("BCA") framework for DER solutions as NWAs***: The OEB launched a separate initiative to develop the components of the BCA Framework. The first phase of work, to develop guidance, methodologies and tools for distribution impacts, is

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[173] Electric Autonomy Canada. Understanding Demand Charges Part 1: What are they and why they need to change. March 9th, 2022.

[174] OEB. Framework for Energy Innovation: Setting a Path Forward for DER Integration. January 2023. Page 3.

[175] Ibid.

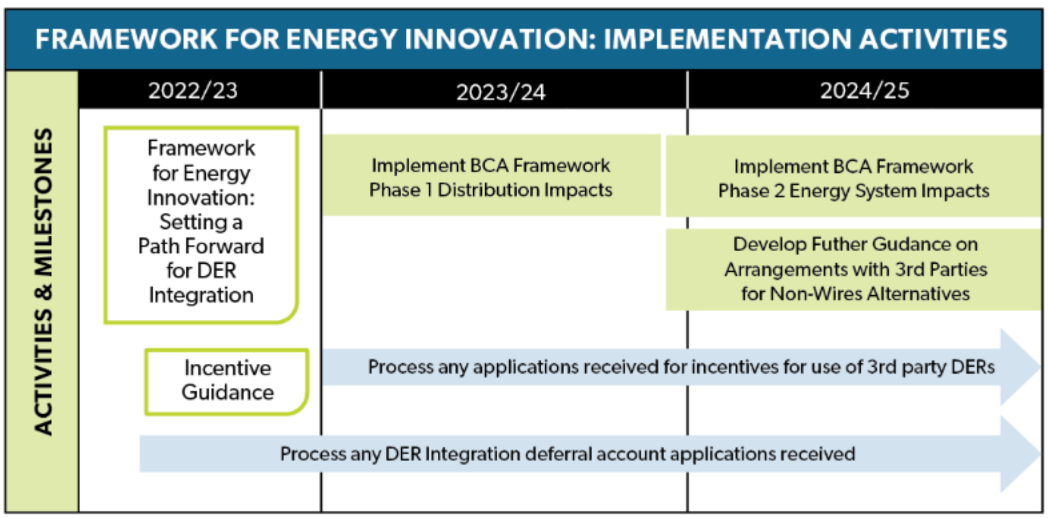
expected to be completed by the end of the 2023/24 fiscal year (the OEB outlined the methodology in a May 2024 report), followed by a second phase focused on the broader energy system impacts by the end of the 2024/25 fiscal year.

3. ***Utility incentives for third-party owned DERs as NWAs***: To alleviate uncertainty about the types of costs that may be recovered, distributors were encouraged to apply for a deferral account to record material operations, maintenance, and administration ("OM&A") costs related to DER integration and use, incurred in advance of their next rebasing application. Upon rebasing, the OEB expected DER-related costs would be fully integrated into distributors' overall spending plans. Distributors were also encouraged to propose an incentive tied to the implementation of third-party owned DER solutions as NWAs, which will inform OEB's consideration of any future incentive policies.

4. ***DER integration***: the OEB stated its intent to launch an initiative to identify any regulatory reforms for facilitating, standardizing, or providing appropriate oversight of arrangements for NWAs between distributors and third-party DER solution providers.

The OEB's implementation timeline is summarized in Figure 17.

Figure 17. OEB's near-term timeline for implementing FEI initiatives



Source: OEB. Framework for Energy Innovation: Setting a Path Forward for DER Integration. January 2023. Page 5.

4.3.2 Relevant jurisdictional/literature review

Major credit rating agencies such as DBRS and S&P Global consider regulatory impacts important when assessing utilities' business risks. LEI has reviewed the key mechanisms and factors considered by the rating agencies.[176] In addition, LEI has presented a UK case study describing

[176] LEI has described the views of S&P and DBRS on the Ontario regulatory regime in Section 4.11.1. S&P and DBRS generally consider the Ontario regulatory regime to be very credit-supportive and one of the strengths in credit rating evaluation.

the regulatory impact assessment mechanism utilized by Ofgem to review the impacts of major regulatory changes.

DBRS

The DBRS corporate rating process consists of four components: (i) the business risk assessment ("BRA"); (ii) the financial risk assessment ("FRA"); (iii) overlay considerations; and (iv) specific instrument considerations (such as long-term corporate bonds and short-term commercial paper).[177,178]

One of the primary factors of the BRA is the regulatory regime under which a utility operates. According to DBRS, a *supportive regulatory framework contributes to stable cash flow and earnings, unpinned by a fair rate of return and a full and timely recovery of costs*.[179] Eight aspects are considered to assess the quality of the regulatory framework:

1) **Deemed equity ratio**: A higher deemed equity ratio implies higher earnings, resulting in a higher score;
2) **Allowed ROE**: A higher allowed ROE generally implies higher earnings, resulting in a higher score;
3) **Energy cost recovery**: DBRS evaluates a utility's ability to recover the purchased energy costs from customers promptly; a higher score reflects stronger ability;
4) **Capital cost recovery ("CCR") and operating cost recovery ("OCR")**: DBRS evaluates the likelihood of a utility's capital expenditure ("capex") being added to its rate base, the timing of the addition, the regulatory lag, the mechanism regarding cost overruns, and the degree of volume risk for the recovery of both costs; an ideal company would have (i) CWIP added to the rate base if capex is significant; (ii) interim base-rate increments frequently authorized; (iii) future test periods fully incorporated for rate-case decisions; iv) rate cases decided within one year; (v) a reasonable mechanism to deal with cost overruns; and vi) no volume risk;
5) **Cost-of-Service ("COS") versus IRM**: DBRS views COS as lower risk than IRM and assigns a higher score to COS; an IRM with a shorter period is assigned a higher score than the one with a longer period;

[177] DBRS. Global methodology for rating companies in the regulated electric, natural gas, and water utilities industry. September 2022.

[178] An overlay factor positively or negatively modifies the core assessment derived from the combination of the BRA and FRA, with the impact of a single factor potentially ranging from less than one notch to as much as several notches in the case of more significant factors. DBRS considers both sector-specific (such as composition of capital spending and adequacy of energy supply) and general overlay factors (such as parent-subsidiary relationship and environmental, social, and governance ("ESG") considerations).

[179] DBRS. Global methodology for rating companies in the regulated electric, natural gas, and water utilities industry. September 2022.

6) **Political interference**: Political interference refers to the incidents where i) the regulator's ability to independently and impartially arrive at a decision is influenced; ii) legislation is passed to override a decision; and iii) the regulator is elected instead of appointed; a higher score reflects less political interference;
7) **Stranded cost recovery**: Stranded costs occur when a utility has incurred the costs but is uncertain as to when it can recover the costs; DBRS evaluates whether stranded costs exist and their magnitude as well as the time it takes to recover the costs; a higher score reflects less or no stranded cost and fully recovered without regulatory lag (if stranded costs exist); and
8) **Rate freeze**: A utility experiences increasing operation and energy costs during the rate freeze period. Thus, a longer rate freeze period or more frequent rate freeze incidents lead to more risk for the utility, resulting in a lower score.

S&P Global

S&P Global considers *regulatory advantage* a key consideration when assessing regulated utilities' risk profile *because the influence of the regulatory framework and regime is of critical importance*, and it *defines the environment in which a utility operates and has a significant bearing on a utility's financial performance*.[180] The regulatory advantage assessment is based on the following factors:[181]

1) **Regulatory stability:** S&P Global monitors the predictability and consistency of the regulatory framework over time. Greater consistency reduces uncertainty for the utility and its stakeholders.
2) **Tariff-setting procedures and design:** This is based on whether all operating and capital costs can be recovered in full and how the rate scheme balances the interests and concerns of all stakeholders. S&P Global looks for achievable, contained, and symmetrical incentives (mostly indexed to overperformance and underperformance).
3) **Financial stability:** If costs are recovered in a timely manner, cash flow volatility can be avoided. Greater flexibility is seen as favorable because it allows for the recovery of unexpected costs. Financial stability also depends on the framework's ability to attract long-term capital and the availability of capital support during construction to alleviate funding and cash flow pressure when heavy investment is needed.
4) **Regulatory independence and insulation:** This is considered stronger when the market framework and energy policies support the long-term financial stability of the utilities, are clearly enshrined in law, and protect the regulator's independence. Where there is limited risk of political intervention, the regulator is considered to be more able to efficiently protect the utility's credit profile, even during a stressful event.

[180] S&P Global Ratings. Sector-Specific Corporate Methodology. April 4th, 2024. Page 147.

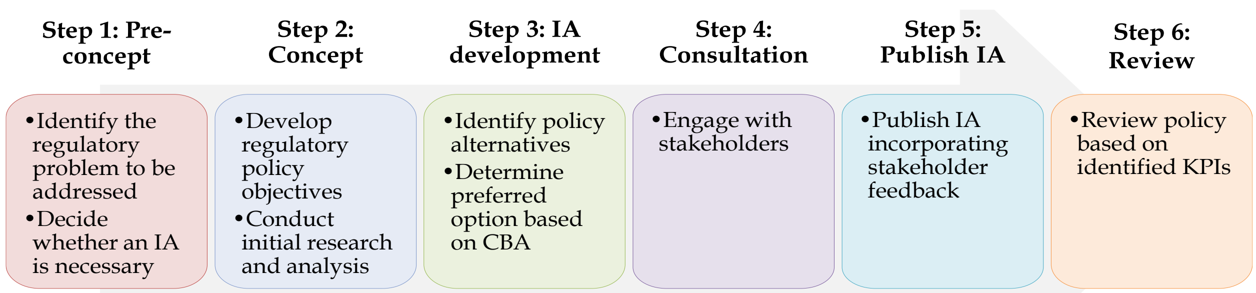
[181] Ibid.

United Kingdom

Ofgem uses impact assessments ("IAs") to concisely summarize the impacts of proposed policy alternatives, including the qualitative and quantitative costs and benefits associated with each option. For accessibility and clarity purposes, Ofgem publishes IAs alongside its policy decisions where appropriate. If Ofgem decides not to conduct an IA for a particular policy (i.e., if it is deemed impractical or inappropriate), the agency issues a statement discussing the reasons for its decision.

IAs are used by Ofgem to understand "the impacts of important policy proposals on consumers, industry participants, society and the environment." Specifically, IAs help assure that when Ofgem makes a policy decision, it does so in a way that "best protects the interests of existing and future customers. This includes balancing the benefits of any action ... against the costs that may arise because of those requirements." According to Ofgem, its IA process "reflects best practice and ensures that [its] approach to compiling the evidence that underpins [its] decisions is proportionate, consistent and transparent." The IA process typically comprises six stages (see Figure 18): (i) pre-concept work; (ii) concept work; (iii) IA development; (iv) consultation process; (v) publication of final decision; and (vi) post-implementation review. The cost-benefit analysis ("CBA") component of the IA is generally conducted in Step 3 of the process.

Figure 18. Ofgem's indicative Impact Assessment process



Source: Ofgem. *Impact Assessment Guidance.* May 4, 2020. *Adapted from Figure 1 (P. 18).*

Ofgem uses the net present values ("NPVs") resulting from the CBA to compare policy alternatives. In addition, the CBA approach involves a sensitivity analysis to test various assumptions. Ofgem notes that "[w]here quantitative assessments are included, they will often be presented as ranges (which may be broad) in order to illustrate the plausible margin of error or uncertainties of any forecast costs and benefits." For any costs or benefits that are difficult to quantify, Ofgem includes qualitative analysis through "a discussion of how pivotal the qualitative or non-monetized costs and benefits are in the cost-benefit analysis assessment."

4.3.3 Potential alternatives

The OEB should consider the risks from regulatory mechanisms that can potentially impact the future cash flows of the utility (either adversely or favorably), such as the regulatory mechanisms reviewed by LEI in Section 4.3.1.

With respect to alternate ways of considering the risk factors, the OEB may adopt one of the three options below:

1. **Status quo:** The OEB considers regulatory risks whenever it assesses potential change in business/financial risks following an application from the utility/intervenors.
2. **Consider IAs for material regulatory changes at the time of introduction** (similar to the UK example) **in addition to the status quo**;
3. **Consider the changes in regulatory risk at defined intervals:** As described in Section 4.2.3, the OEB can set a pre-defined interval (e.g., 1, 3, or 5 years) to assess material changes in business and financial risks, including regulatory risks and rate-setting mechanisms, and determine their impacts (if any) on the capital structure and/or the ROE allowed to utilities. Upon assessment, if the OEB determines that the utility's risk profile has increased (or decreased), it can make commensurate adjustments by increasing (or decreasing) the allowed equity thickness and ROE.

4.3.4 Recommendations

As the perceived stability of future cash flows is a key consideration for investors, a regulated utility's ability to recover its capital and operating costs profoundly relies on the available regulatory mechanisms. As such, they play an outsized role in increasing or decreasing utilities' business and financial risks. The examples reviewed by LEI in Section 4.3.2 indicate that rating agencies consider a number of regulatory mechanisms and factors to assess regulatory risks. However, they primarily rely on assessing how these mechanisms affect the stability of future utility cash flows. As such, LEI recommends that any regulatory mechanism that can significantly impact the stability of future cash flows must be considered for review as part of regulatory risks.

With respect to the major OEB regulatory mechanisms introduced since 2006, LEI believes that they have generally reduced the risks for electricity distributors:

- The RRFE framework introduced in 2012 allowed more flexibility to distributors. Distributors were allowed to choose from a list of three IR options based on their specific needs (compared to a single price cap option in 3rd generation IR). The larger distributors, in particular, have benefited from proposing a custom IR framework tailored to their requirements. For instance, Toronto Hydro, in its latest custom IR application (EB-2023-0195), proposed an alternative labour index for Toronto-specific salary and wages to determine the annual inflation factor stating that it could be more suitable to account for the localized inflationary cost pressures that the utility faces in the 2025-2029 rate period.[182]
- The rate design changes for residential, commercial and industrial customers will ensure more certainty in revenue collection as the rate design has completely transitioned to fixed

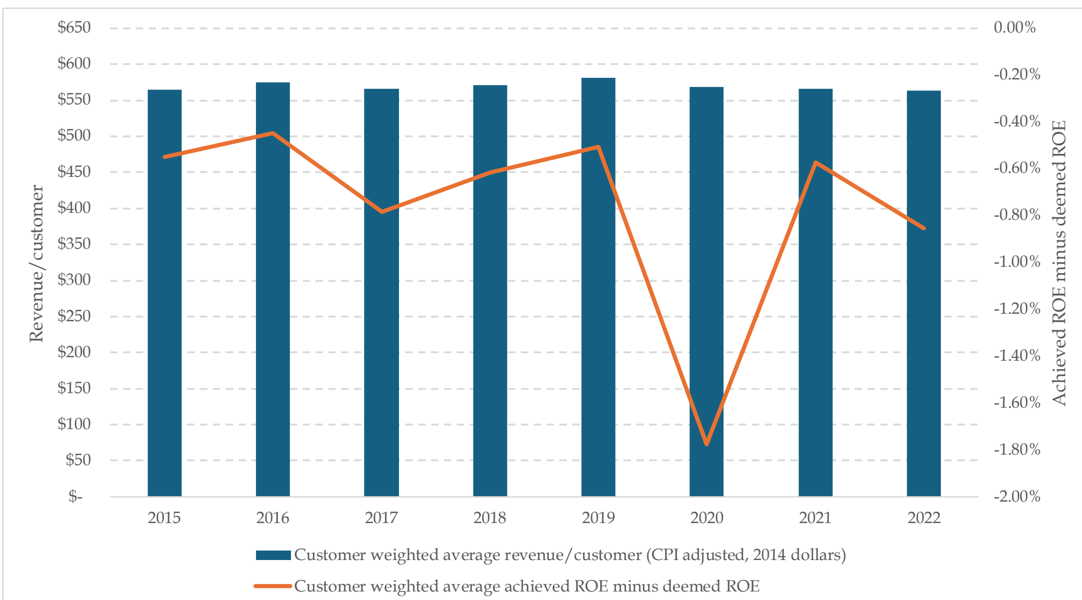
[182] In response to the OEB's interrogatory 1B-STAFF-93, Toronto Hydro withdrew its request for a custom labour component for the inflation factor. However, Toronto Hydro had the option to justify its proposal for a custom I factor.

billing determinants. The rate design changes for commercial and industrial customers should also align more with their investment needs.

- Although the penetration of DERs introduces some uncertainty into future investment plans, the OEB has provided reasonable clarity in this regard, including encouraging the distributors to apply for a deferral account to record material OM&A costs related to DER integration in their next rebasing applications.
- The OEB processes for approving DVA balances and carrying charges have not changed materially since 2006. However, the OEB has established several new DVAs since 2006, which LEI believes have reduced risks for utilities.

The revenue stability for distributors is visible in actual revenue earned per customer (CPI adjusted) since 2015 (see blue bars in Figure 19 below). The achieved ROE (relative to deemed ROE) has also been generally stable since 2015, with the exception of 2020 which was affected by the COVID-19 pandemic (see the line in Figure 19 below).

Figure 19. Actual CPI adjusted revenue per customer and achieved ROE minus deemed ROE for 54 Ontario electricity distributors (2015 – 2022)



Note: Although the OEB tracks annual data for 54 electricity distributors, the number of OEB-regulated electricity distributors is higher than 54.

Source: OEB open data (data available since 2015 only).

LEI recommends impact assessments for major regulatory changes at the time of introduction i.e., before the changes goes into effect (similar to the UK example) in addition to the status quo. This will enable the OEB to proactively increase/decrease the deemed equity thickness if warranted following material regulatory changes. As such, LEI recommends reviewing business /financial risks for electricity distributors at the time of major regulatory changes and adjusting the allowed equity thickness accordingly based on the review's outcome.

As noted by OEB in 2009, most risk factors (including regulatory risks) tend to be stable over time. Thus, considering their impacts at pre-defined intervals is administratively 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, with proactive IAs for following material changes.

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- Any regulatory mechanism that can significantly impact the stability of future cash flows must be considered for review as part of regulatory risks.
- The current policy of considering the impact of risk factors on request when there is a significant change in business/financial risks (including regulatory risk) is a reasonable approach, which LEI recommends be retained.
- In addition, LEI recommends proactive IAs following material regulatory changes.

4.4 Short-term debt rate – appropriateness of existing methodology

Issue 4: ***Should the short-term debt rate*** for electricity transmitters, electricity distributors, natural gas utilities, and OPG ***continue to be set using the same approach*** as set out in the OEB Report?

This Section explores if the current approach to DSTDR methodology and application continue to be appropriate.

4.4.1 Status quo

To determine the DSTDR (as presented earlier in Figure 5), the OEB obtains estimates of the spread of a typical short-term loan for an R1-low utility over the 3-month BA rate from major Canadian banks.[183,184,185] The selection of R1-low is intended to reflect the credit rating of electricity distributors. The OEB aims to obtain quotes from up to six banks (with the intent to discard high and low estimates to reduce the impact of outliers).[186] The OEB calculates the 3-month BA rate by averaging the daily rates for all business days for the month three months in advance of the

[183] The selection of R1-low was meant to reflect the credit status of most Ontario electric distributors, except for Toronto Hydro Electric Systems Limited and Hydro One Networks Inc. (the two of which had a credit status of R1-Mid or R1-High in 2009). However, the rating for Toronto Hydro Electric Systems Limited and Hydro One Networks Inc. is currently R1-low and has remained so since at least 2013 and 2015 respectively. Source: OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

[184] Morningstar DBRS's rating scale for commercial paper and short-term debt is as follows (highest to lowest credit quality): R-1 (high), R-1 (middle), R-1 (low), R-2 (high), R-2 (middle), R-2 (low), R-3, R-4, and R-5 . Source: Morningstar DBRS. Product Guide. February 2024.

[185] As of May 2024, the credit status of electric distributors (including Toronto Hydro and Hydro One) is R1-low. Source: DBRS Morningstar.

[186] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009. Page 57.

effective date for rates (typically calculated towards end of September for rates effective from January 1 of the subsequent year).

For electricity distributors and electricity transmitters, the DSTDR is used to set short-term debt rates.

For natural gas distributors and OPG, the DSTDR is not used to set short-term debt rates. Short-term debt is used for an unfunded portion to true-up the deemed capitalization to the utility's actual capitalization (the portion is generally small).[187] In rate applications, natural gas distributors and OPG provide forecasts of short-term debt rates based on their actual debt portfolio.

In recent rebasing applications (EB-2022-0200 for Enbridge Gas and EB-2020-0290 for OPG), the 5-year average for the short-term debt component (2018-2022 for Enridge Gas and 2016-2020 for OPG) was 2.7% and 0.7% for Enbridge Gas and OPG respectively.[188,189]

For electricity distributors and transmitters, the DSTDR is applied for 4% of the deemed capital structure i.e., 40% equity, 56% long-term debt and 4% short-term debt.

4.4.2 Relevant jurisdictional/literature review

Typically, most utilities have long-term debt and common equity outstanding, while only a few utilities have short-term debt and preferred stock outstanding.[190] Some regulators will exclude short-term debt with the view that it is temporary and will eventually be replaced with long-term capital.[191] The regulators did not specifically opine on short-term debt rates in the jurisdictions reviewed by LEI (Alberta, Australia, BC, California, New York and the UK).

Among all US states, only 13 have considered the short-term debt rate when determining cost of capital parameters and capital structures by evaluating the company's actual/forecast short-term debt rate and/or third-party sources such as the Federal Reserve commercial paper rate, JPMorgan Revolver, or the London Interbank Offered Rate ("LIBOR") (see Figure 20).

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187 Ibid. Page 55.

188 OEB. EB-2022-0200. Exhibit 5. Tab 1. Schedule 1. October 31st, 2023.

189 OEB. EB-2020-0290. Exhibit C1. Tab 1. Schedule 1. October 31st, 2020.

190 United States Agency for International Development ("USAID"). Prepared by the National Association of Regulatory Utility Commissioners ("NARUC"). Cost of capital and capital markets. December 2019. Page 11.

191 Ibid.

Figure 20. Summary of the jurisdictional review of US states for short-term debt rate

State	Utility	Cost of short-term debt
Connecticut	Connecticut Natural Gas Corp.	30-day A2/P2, non-financial commercial paper rate published by the Federal Reserve
Florida	Duke Energy Florida LLC	Annual short-term debt interest amount (interest expense minus interest income) divided by the 13-month average net short-term debt balance (actual cost of short-term debt)
Hawaii	Hawaii Electric Light Co. Inc.	Actual cost of short-term debt
Illinios	Northern Illinois Gas Co.	Actual cost of short-term debt
Kentucky	Columbia Gas of Kentucky, Inc.	13-month average cost rate of the short-term debt for the period ending December 31 of the test year (actual cost of short-term debt)
Maine	Central Maine Power Co.	Actual cost of short-term debt
Michigan	Consumer Energy Co.	Actual cost of short-term debt
Minnesota	CenterPoint Energy Reosurces Corp.	Actual cost of short-term debt
North Dakota	Montana-Dakota Utilities Co.	12-month average short-term debt balance of the current year and pro forma of the test year (actual cost of short-term debt)
Pennsylvania	Columbia Gas of Pennsylvania Inc.	Average of Bloomberg's three-month forecasted London Interbank Offered Rate from the first quarter of the test year through the fourth quarter of the test year, plus a 2 spread for NiSource commercial paper
Tennessee	Kingsport Power Co.	Actual cost of short-term debt
Virginia	Appalachian Power Co.	Actual cost of short-term debt
Wisconsin	Madison Gas and Electric Co.	Actual cost of short-term debt

Note: In November 2020, following the announcement of the formal end date for representative USD LIBOR, US banking regulators issued guidance noting that supervised entities should stop new use of USD LIBOR as of December 31st, 2021. June 30th, 2023, then marked the cessation of all USD LIBOR panel settings—the final major step in the transition. Today, the Secured Overnight Financing Rate ("SOFR") is the dominant U.S. dollar interest rate benchmark. Source: NY Fed.

Source: S&P Capital IQ.

4.4.3 Recommendation/Is the status quo appropriate?

The 3-month BA rate is not an appropriate component any longer for DSTDR determination. This is primarily because the Canadian Fixed-Income Forum ("CFIF"), a group set up by the BoC to facilitate the sharing of information between market participants and the BoC on the Canadian fixed-income market, recommended a path for winding down the BA market in October 2023.[192]

The recommendation stated that the major Canadian banks will not be issuing BAs after the cessation of Canadian Dollar Offered Rate's ("CDOR") publication in June 2024.[193] CDOR was the most commonly used BA benchmark, and most BA facilities referenced CDOR as the interest rate benchmark for establishing the base borrowing rate to which a stamping fee was added.[194]

In July 2023, the Canadian Alternative Reference Rate ("CARR") working group published a set of documents to support the transition of the Canadian loan market from CDOR to the Canadian

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[192] Bank of Canada ("BoC"). CFIF recommends path for winding down BA market. October 16th, 2023.

[193] BoC. CFIF recommends path for winding down BA market. October 16th, 2023.

[194] BoC. A Primer on the Canadian Bankers' Acceptance Market. June 2018. Page 8.

Overnight Repo Rate Average ("CORRA").[195] CORRA is an overnight risk-free rate that closely tracks the BoC's policy, or target rate.[196] Major Canadian banks (such as RBC and Scotiabank) have stated that they will transition all existing financial products that reference CDOR or BAs to referencing CORRA on or before June 28th, 2024.

LEI has discussed alternative options for DSTDR determination and LEI's recommended option in the subsequent Section 4.5 (Issue 5).

LEI recommendations - Issue 4

The current DSTDR methodology (3-month BA rate plus a spread) is no longer appropriate as major Canadian banks will transition all existing financial products that reference CDOR/BAs to referencing CORRA on or before June 28th, 2024.

4.5 Short-term debt rate – recommended revisions to existing methodology

Issue 5: If no to Issue #4, ***how should the short-term debt rate be set***?

This section discusses the potential alternatives and LEI's recommendation for DSTDR determination and application.

4.5.1 Potential alternatives

Considering the transition away from BA products and CDOR reference rates, the status quo approach is no longer a practical alternative. As mentioned earlier, CARR has indicated that financial contracts referencing CDOR (or BAs) need to be prepared to transition such contracts to CORRA or term CORRA (forward-looking indicators such as CORRA futures).[197,198,199]

LEI has identified the following four alternatives for determining DSTDR:[200]

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195 BoC. CARR publishes its recommendations for transitioning loans from CDOR to CORRA and provides a "no new CDOR or BA loan" milestone. July 27th, 2023.

196 BoC. Transitioning Loans from CDOR to CORRA – Best Practices. July 27th, 2023.

197 BoC. CARR reiterates that market participants with CDOR-based loans, derivatives or securities must prepare for CDOR's cessation post June 28, 2024. April 30th, 2024.

198 The prime lending rate is not a reasonable potential alternative to CORRA. LEI has not considered the prime rate a reference rate because prime (or prime+) lending products are typically utilized by entities with poor credit quality (DBRS short-term credit rating of R-3 or R-4). Source: BoC. A Primer on the Canadian Bankers' Acceptance Market. June 2018. Page 6.

199 Based on LEI analysis, all (or most) OEB-regulated utilities have a short-term DBRS credit rating of R1-low. LEI was able to obtain the data for OPG, Enbridge Gas, EPCOR, Hydro One, and 12 electricity distributors.

200 If the OEB staff prefers to move away from conducting confidential surveys, it can ask the utilities to submit actual quarterly data on short-term debt rates in the last five years (2019 to 2023). The actual short term rates can be

1. CORRA as a reference rate ***plus*** spread determination based on a confidential survey of banks;
2. CORRA as a reference rate (similar to #1) ***plus*** spread determination based on a survey of regulated utilities;
3. Current 3-month CORRA futures rate ***plus*** spread determination based on #1; and
4. Average of 3-month CORRA futures rates for the next 12-month period ***plus*** spread determination based on #1.

The subsequent paragraphs discuss the above alternatives in more detail.

1. CORRA as a reference rate plus spread determination based on a confidential survey of banks

The BoC publishes daily data for CORRA, which can be used as a reference.[201] For instance, the OEB can consider the average daily rates for the month of September, similar to the current OEB methodology for the 3-month BA rate. Since CORRA is an overnight risk-free rate, it has historically been slightly lower than the 3-month CDOR. Based on a Bloomberg analysis, the official recommendations from CARR suggest adding 32.138 bps to CORRA to be comparable with the 3-month CDOR.[202] Consequently, the spreads associated with CORRA will be different from the spreads over the 3-month BA rate/CDOR.

In determining the spreads, the OEB's current methodology of surveying top Canadian banks can be strengthened by considering a larger sample size of banks (at least 6-10 banks) to obtain CORRA based spreads for R1-low rated entities. The OEB can consider the banks from the list of 35 banks classified as Schedule 1 banks (domestic lenders), many of which offer short-term lending products to businesses.[203] In addition, LEI believes that the OEB may consider excluding outliers from the sample only if they are significantly different from their nearest quotes (for instance, if the outlier lies outside the range of 2 standard deviation from the mean). In most cases, the outliers may convey useful information about market rates.

2. CORRA as a reference rate (similar to #1) plus spread determination based on a survey of utilities

The OEB may also consider surveying the utilities quarterly/annually instead of (or in addition to) the confidential bank survey. Even if the utility survey results are not utilized in the DSTDR methodology, the data from this survey can be used to verify the validity of the DSTDR methodology. Alternatively, the OEB can direct the utilities to submit actual cost of capital data

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compared with corresponding 3-month BA rates to determine the spread. To adjust for CORRA, the OEB can add 32.138 bps to the actual spread (official adjustment recommendation for CORRA to be comparable with 3-month BA rates). The spread determined by the OEB may be applicable for the next five years.

[201] BoC. Canadian Overnight Repo Rate Average. Accessed on May 10th, 2024.

[202] National Bank of Canada. CDOR-CORRA Transition Update. August 14th, 2023.

[203] Department of Justice Canada. Bank Act (S.C. 1991, c. 46). SCHEDULE I (Section 14). As of December 31st, 2023.

(including actual short-term rates) annually. The utilities are already required to report their audited financial information (such as earned ROE) on an annual basis.[204] The actual cost of capital information can be reported at the same time.

3. Current 3-month CORRA futures rate plus spread determination based on #1

The CARR published its recommended methodology for calculating a forward-looking term CORRA interest rate benchmark in January 2023.[205] While the CARR expected CORRA to be the primary interest rate benchmark in Canada, it recognized that the creation of a robust term CORRA reference rate is important for the transition of the Canadian loan and trade finance market from CDOR to CORRA.[206] The CARR expected most borrowers to prefer the term CORRA (as they are forward-looking rather than the historical rates referenced by overnight risk-free rates) based on a precedent from the US in transitioning from USD LIBOR to the secured overnight financing rate ("SOFR").[207]

Accordingly, the Montréal Exchange ("TMX") launched a 1-month and 3-month CORRA based on CORRA futures.[208] CORRA futures have seen increased usage i.e., higher liquidity, and weekly trading volumes have steadily climbed throughout 2023 and 2024.[209] In particular, the 3-month CORRA futures (with product symbol "CRA") has seen significantly higher volumes compared to 1-month CORRA futures (with product symbol of "COA").[210]

In this alternative, the CRA settlement price for the latest expiry date will be considered as the reference rate. For instance, as of May 11th, the CRA has a settlement price of 94.9725 for expiry on June 19th, 2024.[211] The CRA price is quoted as '100 – R' where 'R' is the compounded daily CORRA for the contract month.[212] As such, investors expect CORRA of 5.03% (100 – 94.9725) in June 2024.

The spread over CORRA can be determined based on the confidential survey of banks (same as #1).

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[204] OEB. Electricity Reporting and Record Keeping Requirements. Effective March 8th, 2023.

[205] BoC. Term CORRA Methodology - CARR Recommended Approach. January 11th, 2023.

[206] Ibid.

[207] BoC. Recommended CORRA loan agreement definitions and loan mechanics. July 27th, 2013.

[208] TMX. CORRA futures. Accessed on May 11th, 2024.

[209] National Bank of Canada. CDOR-CORRA Transition Update. August 14th, 2023.

[210] TMX. Quotes. Accessed on May 11th, 2024.

[211] Ibid.

[212] TMX. 1-Month and 3-Month CORRA Futures Overview. Accessed on May 11th, 2024.

4. Average of 3-month CORRA futures rates for the next 12-month period plus spread determination based on #1

The OEB determines the DSTDR for a 12-month period. As such, estimating the average of implied CRA rates for a similar forward-looking period can be considered as more representative of the rates that utilities may receive. An illustrative calculation is shown in Figure 21 below.

Figure 21. Average of 3-month CORRA futures rates for the next 12-month period (illustrative calculation)

Symbol	Class symbol	Settlement price (as of May 11th, 2024)	Expiry date	Implied rate
CRAM24	CRA	95.1700	9/18/2024	4.830%
CRAU24	CRA	95.3800	12/18/2024	4.620%
CRAZ24	CRA	95.5800	3/19/2025	4.420%
CRAH25	CRA	95.7550	6/18/2025	4.245%
Average				**4.529%**

Source: TMX.

Application of DSTDR methodology

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

1. Status-quo: As described in Section 4.4.1, the DSTDR currently only applies to electricity distributors and transmitters on 4% of the deemed capital structure.
2. Uniform application of DSTDR for all utilities: The DSTDR is applicable for the unfunded portion after deducting from the long-term debt and common equity portions.[213] Under this approach, the actual short-term rates will not be considered.
3. Uniform application of DSTDR as a cap for all utilities: DSTDR is applicable as a cap for the unfunded portion after deducting from the long-term debt and common equity portions. Under this approach, the actual short-term rates will be considered if they are lower than the DSTDR, and the DSTDR will be considered if the actual short-term rates are higher than the DSTDR. This may potentially incentivize the utilities to improve their credit profile and/or negotiate better borrowing terms if their rates are higher than the DSTDR.

4.5.2 Recommendations

The average CRA (3-month CORRA futures) determined over the relevant forward-looking 12-month period (see Figure 21) is more representative of investor expectations of short-term rates over the next year, in line with potential BoC policy rate reduction expectations. For instance, as

[213] 'Unfunded portion' implies that the short-term debt portion should be considered as a plug in the capital structure only if deemed equity portion (%) and the actual long-term debt portion (%) add up to less than 100%.

per the current approach, the OEB would consider the futures rate for 2025 (average of implied rates for March, June, September, and December 2025) based on data as of September 30th, 2024.

The spread can continue to be determined based on the confidential survey of banks. However, LEI recommends considering a larger sample size (of at least 6-10 banks) for the survey to obtain CORRA-based spreads for R1-low rated entities (similar to OEB-regulated entities).

With respect to the application of DSTDR, LEI recommends considering the DSTDR for all utilities, not just electricity distributors. Consistent with the principles outlined by LEI in Section 3.1, this approach is administratively simple to administer and fair to both utilities (as the DSTDR is determined for R1-low rated entities, and currently, the OEB-regulated entities – including electricity distributors, Enbridge Gas and OPG have an R-1 rating) and consumers (as the DLSTDR is applied as a cap). Furthermore, the transition to a different benchmark is appropriate as the existing CDOR/BA based benchmark is no longer practical.

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- For reference rate, LEI recommends considering the average of 3-month CORRA futures rates for the next 12-month period.
- The spread for a R1-low rated utility over CORRA to be determined from an annual confidential survey of banks (slightly modified from status quo vis-à-vis larger sample size of 6-10 banks and limited exclusion of outliers).
- DSTDR to be applied as a cap for all utilities.

4.6 Long-term debt rate – appropriateness of existing methodology[214]

Issue 6: ***Should the long-term debt rate*** for electricity distributors, natural gas utilities, and OPG ***continue to be set using the same approach*** as set out in the OEB Report and as set out in the Staff Report for electricity transmitters?

This section explores if the current approach to DLTDR methodology (and application) continues to be appropriate.

4.6.1 Status quo

The OEB sets the DLTDR for the test year equal to LCBF plus the average spread between a 30-year A-rated Canadian utility bond yield and the 30-year GoC bond yield for all business days in the month, which is three months preceding the effective date for the rate changes.[215] The current DLTDR formula was presented earlier in Figure 4.

[214] OEB Report, pp. 50-55, 59; EB-2009-0084, OEB Staff Report, Review of the Cost of Capital for Ontario's Regulated Utilities (Staff Report), January 14, 2016, p. 3 Table 1.

[215] The A-rated Canadian utility bond yield is derived from the Bloomberg utility series C29530Y.

The forecast yield for LCBF is calculated by taking the average of the 3-month and 12-month 10-year Government of Canada bond yield forecasts, as stated in the relevant issue of Consensus Forecasts, and adding the average of the actual observed spreads between 10-year and 30-year Government of Canada bond yields, for each business day in the month corresponding to the most recent Consensus Forecast issue. While the approach was presented earlier in Figure 4, for ease of review, the formula is as follows: LCBF = 10-year GoC bond yield forecasts + yield spread of 30-year GoC bonds over 10-year GoC bonds.

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 when determining the annual revenue requirement for the rebasing year.[216]

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).[217] 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.

4.6.2 Relevant jurisdictional review

Australia and the UK use formulaic approaches to determine the allowed return on debt. NY and California determine the allowed return on debt on a case-by-case basis, based on the actual, embedded cost of debt. Their respective approaches are discussed below.

Australia

The AER estimates the allowed return on debt using a trailing average portfolio approach. AER calculates the simple average of rates observed over a ten-year trailing period by NSPs and

[216] OEB. OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016.

[217] Ibid.

updates the rate annually.[218] The AER uses a debt term of ten years as this aligns with the debt financing practices of regulated businesses to issue longer-term debt[219] and is consistent with the consensus of NSPs and investors.[220]

The AER specifies a debt portfolio of a benchmark credit rating of BBB+, using third-party yield curve data from the Reserve Bank of Australia ("RBA"), Bloomberg, and Refinitiv, to estimate the allowed return on debt for an NSP. However, since no such index is available, the AER instead uses a weighted average with 2/3rd weight on BBB-rated bond indices, and 1/3rd weight on A-rated bond indices. The AER noted that the benchmark credit rating of BBB+ reflects the current average rating of issued debt by NSPs.[221]

To mitigate the daily volatility of market rates, the AER has decided to estimate the return over a specific averaging period. NSPs nominate the averaging period. The averaging period starts no earlier than 17 months before, and ends no later than five months before the start of the relevant regulatory period (i.e. assuming the regulatory period starts in January 2024, the averaging period must be within the period of August 2022 to August 2023).[222]

The AER developed the Energy Infrastructure Credit Spread Index ("EICSI") in 2018. This index reports a rolling 12-month historical average of credit spreads across all new debt issuances by privately owned NSPs. It is used as a *sense check* on the AER's benchmark return on debt approach.[223]

Furthermore, the AER continues the transition, where NSPs undergo a ten-year transition period to move from the previous *on-the-day* approach to the trailing average approach.[224] This means that any new NSP receives the on-the-day cost of debt, which is approximately 6.5% as at end of December 2022,[225] while existing NSPs receive their trailing averages. The AER started the transition process in 2013, and noted that *a trailing average approach is expected to better account for*

[218] AER. Rate of return instrument. Explanatory statement. February 2023.

[219] The AER observed that NSPs tend to stagger debt issuances over time, which helps to mitigate refinancing risk. While NSPs issue all kinds of debt instruments, the average term of debt is typically long. The AER determined that individual NSPs' average term of instruments issued since July 2013 ranged from under 5 years to over 12 years, with an average of 8 years if short-term debt is excluded from the average. As such, the AER considered a trailing average approach with a benchmark term of 10 years. Source: Ibid. p.197.

[220] AER. Rate of return instrument. Explanatory statement. February 2023.

[221] Ibid.

[222] Ibid.

[223] Ibid. P.193.

[224] On-the-day approach was applied prior to the 2013 Rate of Return guideline. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

[225] The on-the-day cost of debt is calculated using a 20-day average as at end December 2022. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

a benchmark efficient entity's actual (cash) debt costs within a regulatory period because it provides service providers with a return on debt allowance that they can more readily match each regulatory period.[226]

United Kingdom

Ofgem sets the cost of debt allowance, which is *an estimation of the return debt investors expect from an efficiently run company*,[227] and the rates allowed are different for electricity distributors, electricity/natural gas transmitters, and gas distributors.

For **electricity distributors**, Ofgem uses the yield of the iBoxx GBP Utilities 10yr+ index to index the cost of debt allowance, plus additional borrowing costs of 25 bps. Ofgem also provides an additional six bps for certain electricity distributors issuing less than £250 million annually on a notional basis.

Ofgem considered that the iBoxx Utilities 10yr+ index, including 84 bonds, is a *broad and representative* index.[228] Moreover, the additional borrowing costs of 25 bps were determined based on a bottom-up analysis of additional cost components. The components are shown in Figure 22 below.

Figure 22. Components of additional borrowing costs

Component	Cost	Description
Transaction costs	6 bps	Based on NSPs' data, excluding one outlier
Liquidity/revolving credit facilities	4 bps*	Based on Regulatory Financial Performance Reporting ("RFPR") and group account data about actual RCF holdings
Cost of carry	10 bps**	Derived from RFPR and group accounts data on cash on the balance sheet, with a differential cost between debt and cash
CPIH basis risk mitigation	5 bps***	Derived from RFPR and group accounts data on cash on the balance sheet, with a differential cost between debt and cash

* Ofgem assumes that electricity distributors arrange facilities sized around 10% of debt balances and have a commitment fee of 40 bps, which yields an allowance of 4 bps (i.e. 10% x 40 bps).

** Two inputs are used to calculate the cost of carry. First, Ofgem utilizes RFPR and group account data to establish appropriate levels of cash on balance sheets held across utilities. Second, Ofgem assesses cost of carry based on five-year average difference between the Benchmark iBoxx GBP Utilities 10yr+ index and the three-month cash deposit rate. Ofgem has decided to adopt the upper bound of the point estimate (2-10 bps), taking account possibilities that end-of-year balances may be lower (or higher) than balances at other time during the year, licensees may be required to hold cash for a longer period due to smaller debt balances, and infrequent issuers may face a higher cost of carry.

[226] Energy Networks Australia. Estimating the cost of debt: Response to AER's pathway to 2022 rate of return instrument: Draft debt omnibus working paper. September 3rd, 2021. P.26.

[227] Ofgem. Decision – RIIO-ED2 final determinations Finance annex. November 30th, 2022. P.10.

[228] Ofgem. Decision – RIIO-ED2 final determinations Finance annex. November 30th, 2022. P.12.

*** The 5 bps is made up of an allowance of 3 bps for embedded debt and an allowance of 2 bps for new debt. The embedded debt allowance is based on the potential cost of mitigating Retail Prices Index ("RPI")/Consumer Price Index including owner occupiers' housing costs ("CPIH") basis risk, using an assumption of 15 bps additional cost multiplied by the proportion, calculated using the 17-year trailing average of index-linked debt of 25%, and the implied weight for embedded debt of 78%. The new debt allowance is based on an assumed 30 bps additional cost of CPI or CPIH-linked issuance multiplied by the assumed proportion of index-linked debt of 25% and the implied weight for new debt of 22%.

Source: Ofgem. Decision – RIIO-ED2 final determinations Finance annex. November 30th, 2022.

To calibrate the index for all utilities, Ofgem calculates the allowance using a 17-year trailing average with a fixed upward adjustment of 55 bps.[229] Finally, Ofgem deflates the nominal yields for each date of the trailing average to CPIH[230] real yields using the Office of Budget Responsibility ("OBR") five-year forecast for CPI, available for each date, using the Fisher equation. The real allowed return on debt is the trailing average of the resulting real yields. The debt allowance is updated annually in accordance with updated data for the benchmark index.[231]

Furthermore, the infrequent issuer premium of six bps is applied to utilities expected to issue smaller-sized new debt or issue new debt less frequently than other utilities due to smaller regulatory asset value ("RAV") sizes and/or lower RAV growth. The determination of six bps is derived from a 26-bps premium applied to new debt, multiplied by the proportion of new debt of 22%, based on the costs of a Constant Maturity Swap. The threshold of debt issuance has been set at £250 million per annum as it is consistent with the size of benchmark debt, with £250 million as the minimum threshold for bonds to be included in the iBoxx GBP Utilities 10yr+ index.[232]

Ofgem sets the allowed return on debt for **electricity and gas transmitters and gas distributors** slightly differently from that for electricity distributors but broadly follows a similar approach. The steps of determining the cost of debt for electricity distributors and the differences in approach for other sectors are shown in Figure 23 below.

[229] Ofgem considers that a 55-bps calibration adjustment is sufficient to compensate for expected industry debt costs based on its analysis of a range of modelled scenarios.

[230] CPIH includes every measure from the Consumer Prices Index ("CPI") and owner-occupiers' housing costs. Source: Ofgem. RIIO-2 final determinations – Core document. December 8th, 2020.

[231] Ibid.

[232] Ofgem. Decision – RIIO-ED2 final determinations Finance annex. November 30th, 2022.

Figure 23. Cost of debt determination - UK

Step	Description (electricity distribution)	Description (other sectors)
Index selection	Index the cost of debt allowance using the yield of the iBoxx GBP Utilities 10yr+ index	Same as electricity distributors
Additional costs of borrowing	Add 25 bps to the index above	Same as electricity distributors
Infrequent issuer premium	Add 6 bps for borrowers issuing less than £250 million per year on a notional license basis	Add 6 bps for borrowers issuing **less than £150** million per year on a notional license basis
Calibrating the index – Trailing average period	Calculate the allowance using a 17-year trailing average, plus a fixed upward adjustment of 55 bps to the trailing average	Calculate the allowance using an **extending 10 to 14-year trailing average**
Calibrating the index – Exceptional cases	No exceptional case	**Use a RAV-weighted cost of debt allowance calculation** (only for Scottish Hydro Electric Transmission)
Deflation to CPIH	Deflate nominal yields for each date of the trailing average to CPIH real yields using the OBR forecast for CPI in five-year time using the Fisher equation. The trailing average of the resulting real yields is the real allowed return on debt	Same as electricity distributors

Source: Ofgem.

California

California Public Utilities Commission ("CPUC") determines the cost of long-term debt based on *actual, or embedded, costs*. Future interest rates are considered to reflect projected changes in a utility's cost due to the issuance and retirement of long-term debt.[233] The CPUC acknowledges that actual interest rates vary, and it is tasked with determining a reasonable cost of debt. Consistent with past practice, the CPUC concluded that the latest available interest rate forecast (based on actual debt) should be used to determine embedded debt cost in the cost of capital proceedings.[234]

New York

Similar to California, utilities in NY forecast their rate year cost of debt largely based on their actual, or embedded, cost of outstanding debt and embedded cost rates for new long-term debt issuances, with terms ranging from five years to 30 years, anticipated during the rate year.[235] For

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[233] CPUC. Decision 22-12-031. Decision addressing test year 2023 cost of capital for Pacific Gas and Electric Company, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric Company. December 15th, 2022. Page.12.

[234] Ibid.

[235] National Association of Regulatory Utility Commissioners. Cost of capital and capital markets primer for utility regulators. December 2019.

example, Consolidated Edison Company of New York ("Con Edison") forecasts rate year cost of debt *largely reflects its current actual, or 'embedded', cost of debt*, along with *projections regarding the amounts, timing, maturities, and cost rates for new 30-year debt issuances anticipated during the linking period and the rate year*.[236]

The jurisdictional review is summarized in Figure 24. The jurisdictions reviewed either consider the actual cost of debt or a uniform cost of debt for all utilities based on a formulaic approach.

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

4.6.3 Recommendation/Is the status quo appropriate?

The OEB's status quo methodology can be improved upon. There are several potential sources for long term debt information. LCBF considers Consensus Economics' forward-looking forecast (an average of 3-month and 12-month forecasts) for 10-year GoC bond yields from several reputable sources.[237] The mix of sources considered (such as retail banks, investment banks, economic advisory firms, and academic institutions) are meant to provide a reasonable picture of investor expectations during the survey. However, Consensus Economics only publishes the forecasts for 10-year GoC bonds which necessitates the calculation of spreads for 30-year vs. 10-year GoC bond yields.

The 30-year maturity period considered for LCBF is similar to that of most long-term bonds issued by utilities in Ontario. LEI analyzed the current debt maturity profile for Enbridge Gas, OPG, Hydro One Limited, Toronto Hydro Corporation, Alectra Inc., and Hydro Ottawa Holding Inc. The average maturity period is ~21 years.[238] As the GoC does not issue a 20-year bond, a 30-

[236] NYPSC. Case 22-E-0064 & 22-G-0065. Prepared redacted testimony of staff finance panel. May 2022. Page.47.

[237] The monthly Consensus Forecasts survey report (dated April 8th, 2024) provides 10-year GoC bond yield forecasts from the Economist Intelligence Unit, Economap, BMO Capital Markets, University of Toronto, Scotia Economics, CIBC Capital Markets, Institute for Fiscal Studies, Desjardins, Toronto Dominion Bank, Informetrica, Royal Bank of Canada, Conference Board of Canada, National Bank of Canada, Citigroup, and Oxford Economics.

[238] S&P Capital IQ. Data considered as of May 13th, 2024.

year GoC bond yield is the most appropriate indicator to consider for estimating the LCBF/risk-free rate.

The 30-year A-rated Utility Bond Yield Spread (utility series C29530Y published by Bloomberg) is also consistent with the senior debt rating of most OEB-regulated entities.[239] However, Bloomberg has ceased updating the utility series (C29530Y) as of February 2024. LEI, in consultation with the OEB Staff, has identified Bloomberg's alternative BVCAUA30 BVLI Index. LEI compared the two indices over the May 2023-January 2024 period and found no meaningful difference between the two indices. As such, the switch to the BVCAUA30 BVLI Index does not impact the calculation of DLTDR and ROE under the current methodology.

However, LEI believes there is room for improvement in the methodology and more consistency in its application, i.e., there is no reason for the DLDTR cap to only apply to electricity distributors and transmitters. As such, LEI has provided potential alternatives (in Section 4.7.1) that the OEB can consider.

LEI recommendations - Issue 6
The current OEB methodology for DLTDR is broadly appropriate but can be improved upon.

4.7 Long-term debt rate – recommended changes to existing methodology

Issue 7: If no to Issue #6, ***how should the long-term debt rate be set***?

This section discusses the potential alternatives and LEI's recommended option for DLTDR determination and application.

4.7.1 Potential alternatives

LEI proposes the following alternatives for determining DLTDR:[240]

1. Status quo, however, with a longer 12-month historical data series (relative to the current one-month data series) for 30-year to 10-year GoC bond yield spreads; and
2. Considering publicly available reputable sources for 30-year bond forecasts for LCBF/risk-free rate.

239 Based on LEI analysis, all (or most) OEB-regulated utilities have a DBRS senior debt rating of A. LEI was able to obtain the data for OPG, Enbridge Gas, EPCOR, Hydro One, and 15 electricity distributors.

240 If the OEB prefers to transition towards using only publicly available data series for the determination of utility bond spreads, it may consider Intercontinental Exchange ("ICE") Bank of America ("BofA") Option-Adjusted Spreads ("OAS") for the US, which are available for all major credit ratings. The data is available in the public domain. LEI was not able to locate similar data for Canada.

1. Status quo but with a 12-month historical data series (instead of one month) for 30-year to 10-year GoC bond yield spreads

To determine the spreads for 30-year vs. 10-year GoC bond yields, the OEB currently considers the daily average for the month of September only each year. As such, the resulting sample size is typically not representative of the spreads observed during the whole year (see Figure 25).

Figure 25. Actual monthly average spreads for 30-year vs. 10-year GoC bond yields (2017-2023)

Month/Year	Actual average % spreads (30-year vs. 10-year GoC bond yields)						
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
January	0.62	0.16	0.22	0.12	0.62	0.24	0.05
February	0.69	0.13	0.25	0.13	0.57	0.27	-0.01
March	0.68	0.15	0.29	0.41	0.44	0.18	0.02
April	0.67	0.12	0.29	0.60	0.48	-0.05	0.11
May	0.63	0.04	0.25	0.56	0.59	-0.03	0.06
June	0.53	0.05	0.25	0.52	0.50	-0.10	-0.13
July	0.37	0.04	0.21	0.49	0.53	-0.04	-0.17
August	0.43	0.01	0.24	0.50	0.56	0.03	-0.16
September	0.36	0.01	0.20	0.52	0.54	-0.07	-0.20
October	0.36	0.02	0.14	0.59	0.41	0.00	-0.25
November	0.34	0.05	0.13	0.55	0.34	0.05	-0.20
December	0.27	0.16	0.08	0.54	0.31	0.00	-0.17
Average	**0.50**	**0.08**	**0.21**	**0.46**	**0.49**	**0.04**	**-0.09**
Spreads in September relative to 12-month average	**-0.13**	**-0.07**	**-0.02**	**0.06**	**0.05**	**-0.11**	**-0.11**

Source: BoC.

Were this alternative chosen, LEI recommends considering a larger data series comprising at least the trailing 12-month period, i.e., October to September, if the LCBF is calculated as of September 30th each year. Furthermore, considering the trailing 12-month period is also consistent with the applicable duration of the LCBF (i.e., the 12-month period from January to December for the subsequent year).

Similarly, to estimate the spread over LCBF for a 30-year A-rated utility, Bloomberg's BVCAUA30 BVLI Index can be used (similar to the current approach, but 12-month trailing average instead of one month).

2. Considering publicly available reputable sources for 30-year bond forecasts for LCBF/risk-free rate.

Alternatively, the OEB can directly consider the 30-year GoC bond yield forecasts. Although this approach may result in a slightly smaller sample size of forecasts compared to the status quo approach, this would have two main advantages:

i. it would eliminate the need to determine the 30-year vs. 10-year GoC bond yield spreads, as 30-year GoC bond yield forecasts are readily available from most major Canadian banks; and

ii. it is easily verifiable due to publicly available forecasts (there is no need for a paid subscription to Consensus Forecasts).

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.

consistent with the principles outlined by LEI in Section 3.1. Bloomberg's BVCAUA30 BVLI Index continues to be appropriate for considering the spread over LCBF for a 30-year A-rated utility, as there is no comparable publicly available index available for substitution (but 12-month trailing average, instead of one month).

With respect to the application of DLTDR, LEI recommends the modified status quo approach with DLTDR as a cap but uniformly applicable for all utilities (not just electricity distribution and transmission utilities). All OEB-regulated entities reviewed have a similar senior debt credit rating, and there is no reason to only subject electricity distributors and transmitters to a cap.

LEI recommendations - Issue 7

- LEI recommends considering publicly available reputable sources for 30-year bond yield forecasts for LCBF/risk-free rate.
- Bloomberg's BVCAUA30 BVLI Index (12-month trailing average) is appropriate for considering the spread over LCBF for an A-rated utility.
- DLTDR to be applied as a cap for all utilities.

4.8 Long-term debt rate – transaction costs incurred by utilities

Issue 8 is described in the text box below.

Issue 8: How should ***transaction costs incurred by utilities*** be considered when setting the long-term debt rate?

4.8.1 Status quo

The OEB currently does not consider transaction/financing costs associated with obtaining debt when determining the DLTDR/DSTDR. The utilities reviewed by LEI record the transaction costs as interest expense, amortizing them using the effective interest rate method over the term of the related debt instrument.[242]

For ROE determination however, the current ERP methodology includes an implicit 50 basis points for transaction costs.[243] This is discussed further in Section 4.10.

[242] LEI checked the annual reports for Enbridge Inc., OPG, Hydro One, and Alectra Inc. Each of the reviewed utilities utilizes the effective interest rate method.

[243] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

4.8.2 Relevant jurisdictional review

Australia considers transaction costs as operating expenses. The UK determines a spread based on actual transaction costs. California and NY adjust transaction costs under interest expenses through amortization when calculating the return on debt.

Australia

The AER estimates an allowed rate of return that *does not include transaction costs involved in raising debt and equity capital*.[244] Instead, the costs are compensated through expenditure allowances at each regulatory determination, which results in a simpler estimate of the allowed rate of return and a more transparent and detailed modelling of capital-raising transaction costs.[245]

California

In California, the cost of debt set by the CPUC is *determined by weighted average interest rates on long-term debt issuances, adjusted* for the amortization of *recorded long-term debt financing issuance cost over the life of each security issued*.[246] As such, this is similar to the approach utilized by utilities in Ontario.

New York

Similar to California, the cost of debt determined by the NYPSC is largely based on the embedded cost of outstanding debt, which is usually *calculated as the average embedded interest rate (adjusted for the amortization of issuance costs and discount or premium)*.[247]

For example, Central Hudson, New York State Electric & Gas Corporation ("NYSEG"), and Rochester Gas & Electric Corporation ("RG&E") all stated that the weighted average cost of outstanding long-term debt *can be readily calculated by examining their contractual terms*; *e.g., the interest payments for the long-term debt and the amortization of issuance costs*, while the projected cost of new debt requires estimates using relevant market data.[248,249]

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[244] AER. Rate of return instrument. Explanatory statement. February 2023. P.81.

[245] AER. Rate of return instrument. Explanatory statement. February 2023.

[246] CPUC. Decision 12-12-034. Decision on test year 2013 cost of capital for the major energy utilities. December 26th, 2012. P.6.

[247] National Association of Regulatory Utility Commissioners. Cost of capital and capital markets primer for utility regulators. December 2019. P.14.

[248] NYPSC. Case 23-E-0418 & 23-G-0419. Prepared testimony of Andrew Hale. January 16th, 2024. P.11.

[249] NYPSC. Case 22-E-0317, 22-G-0318, 22-E-0319 and 22-G-0320. Prepared testimony of staff finance panel. September 2022. P. 12.

UK

Ofgem sets an allowance for transaction costs of 6 bps as additional borrowing costs when setting return on debt, reflecting *both ongoing and up-front costs in relation to debt issuance*.[250] The costs include underwriting fees, arrangement fees, listing fees, rating fees, and legal fees. The allowance is the same for all sectors regulated by Ofgem, which is based on the network operator's data, excluding one outlier – a 2009 Electricity North West Limited ("ENWL") bond that differs significantly from other data points.[251]

A summary of the jurisdictional review is shown in Figure 27.

Figure 27. Summary of the jurisdictional review

Jurisdiction	Transaction cost
Australia	Transaction costs compensated through expenditure allowances at each regulatory determination
UK	Based on actual transaction costs, including underwriting fees, arrangement fees, listing fees, rating fees, and legal fees
California	Under interest expenses, adjusted through amortization
NY	Under interest expenses, adjusted through amortization

4.8.3 Potential alternatives

The OEB may consider the following options:

1. Status quo: the OEB can continue to consider transaction costs associated with debt issuance based on actual costs (as interest expenses).
2. Status quo, but considered separately for cost allowance in the rebasing year only if the interest costs are higher than DLTDR/DSTDR: In Section 4.7.2, LEI recommended considering DLTDR/DSTDR as a cap for all utilities (not just electricity distributors and transmitters). The OEB may consider transaction costs separately, only if a utility's interest costs are higher than DLTDR/DSTDR, solely because of higher transaction costs associated with debt issuance.
3. Consider transaction costs as operating expenses (similar to the Australian approach): Not all transaction/financing charges are associated with debt issuance. For instance, in EB-2022-0200 (Exhibit 5), Enbridge Gas has claimed account maintenance and admin fees

[250] Ofgem. Decision – RIIO-ED2 final determinations Finance annex. November 30th, 2022. P.14.

[251] Ofgem. RIIO-ED2 draft determinations – Finance annex. June 29th, 2022.

(upfront fees paid to credit facility agent(s) and lenders) and standby fees (compensation charges for undrawn credit facility amounts) under financing charges. The frequency and amount of debt issuance can also change based on the capital expenditure plan. As such, it is reasonable to expect transaction/financing charges to fluctuate, making it more suitable to be allowed as operating expenses.

4. Consider transaction costs as a separate DLTDR component (similar to the UK approach): The OEB can determine a uniform transaction cost allowance (over and above the DLTDR) based on actual historical transaction costs of OEB-regulated utilities. However, as discussed in #3 above, transaction costs could vary yearly and may not always be appropriate to be represented as a fixed share of debt.

4.8.4 Recommendations

Based on the reasons discussed in alternative #3 above (i.e., irregularity in frequency and amount of debt issuance), LEI believes that considering transaction costs as operating expenses is the most reasonable approach. Consistent with the principles outlined by LEI in Section 3.1, this approach is also fairer to consumers because there is less likelihood of higher cost allowances for utilities, i.e., more than the actual transaction costs incurred by utilities. As such, LEI believes that the benefits to consumers justify the transition away from the status-quo.

LEI recommendations - Issue 8

Transaction costs should be considered as operating expenses, as this approach is more suitable for the nature of the expense, which may fluctuate from year to year.

4.9 Long-term debt rate – implications of variances from the deemed capital structure

Issue 9 is described in the text box below.

Issue 9: What are the ***implications of variances from the deemed capital structure*** (i.e., notional debt and equity) and ***how should they be considered*** in setting the cost of long-term debt?

4.9.1 Status quo

The OEB considers the deemed capital structure when determining the cost of capital. For rate-setting purposes, the *notional debt is used as the "plug" to true up actual debt to the allowed debt thickness*.[252,253]

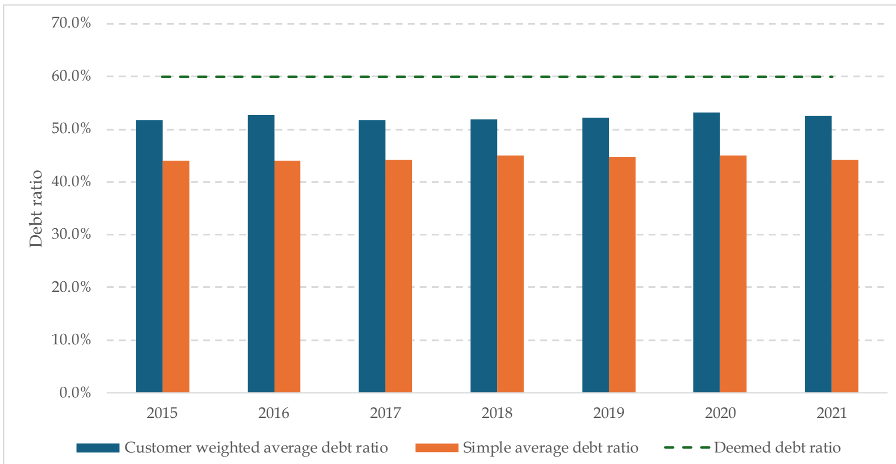
[252] OEB Staff report EB-2009-0084. Review of the cost of capital for Ontario's regulated utilities. January 14th, 2016. Pages 6-7.

[253] OEB policy states that notional debt should attract the weighted average cost of the actual long-term debt rate rather than the DLTDR issued by the OEB. Source: Ibid.

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 actual capital structure of electricity distributors in Ontario is summarized in Figure 28 below. On average, the actual debt ratio is lower than the deemed ratio of 60%. However, the customer-weighted average debt ratios are meaningfully higher than the simple average, which indicates that the capital structure of larger utilities is closer to the deemed capital structure, while smaller utilities finance more of their rate base with equity.

Figure 28. Actual debt ratios for 54 Ontario electricity distributors (2015 – 2021)



Note: Data available for the years 2015 to 2021 only. The OEB did not publish 2022 D/E ratios for electricity distributors, and 2023 data has not yet been published.

Source: OEB open data.

4.9.2 Relevant jurisdictional review

Australia and the UK apply a deemed capital structure for all utilities. California and NY use the actual capital structure of the utilities.

Australia

Under the benchmark regulatory framework, benchmark gearing reflects the AER's view of the efficient level of gearing, not the actual gearing that has been observed for utilities.[254] The AER has observed that the actual gearing ratios change over time.[255] However, it considers that *changes in target gearing ratios are likely to be infrequent* and it sees *no reason to expect movement up or down*.[256]

[254] Capital gearing is a British term for the amount of debt a company has relative to its equity (same as 'financial leverage' and inverse of equity thickness). Source: Investopedia.

[255] The AER notes that the average actual gearing ratio of NSPs fluctuated from 50% to 73% from 2006 to 2022. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

[256] AER. Rate of return instrument. Explanatory statement. February 2023. P.82.

In fact, the AER has shown great consistency in setting the regulatory gearing level at 60% (since 2006), regardless of the fact that the recent data shows average gearing slightly below 60%.[257]

The AER notes that *gearing should not be determined based on spot values during the life of the instrument* as short-term gearing can be influenced by market fluctuations in share prices.[258] Therefore, it is appropriate to apply *a fixed benchmark* over the regulatory period, irrespective of the actual gearing observed for NSPs.[259] In addition, the AER does not note any relationship between the actual gearing ratio to allowed return on debt as it sets a formula to calculate return on debt using data from third-party data providers for a particular benchmark credit rating and term to maturity.[260]

California

The allowed capital structure of a utility in California is *the proportional authorization of shareholders' equity and debt that comprise a company's long-range financing*, including long-term debt, preferred equity, and common equity.[261] In other words, the allowed capital structure is determined using the actual, most recently adopted capital structure and is fixed over the three-year cycle. As such, there is no variance between the allowed capital structure and the actual capital structure in going in rates.

New York

Similar to California, NYPSC determines the capital structure measured at the corporate level of the regulated entity using the actual capital structure ratio for a utility that is ring-fenced,[262] and has market-traded stock and/or debt directly issued to investors.[263]

If the utility is operating under a parent company and not adequately ring-fenced, the NYPSC may consider using the capital structure of the parent company, depending on *the reasonableness of that capital structure in terms of allowing the operating company to maintain reasonable access to capital*.[264]

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[257] AER. Rate of return instrument. Explanatory statement. February 2023.

[258] Ibid. P.82.

[259] Ibid.

[260] AER. Rate of return instrument. Explanatory statement. February 2023.

[261] CPUC. Decision 22-12-031. Decision addressing test year 2023 cost of capital for Pacific Gas and Electric Company, Southern California Edison, Southern California Gas Company, and San Diego & Electric Company. December 15th, 2022. Page.4.

[262] Ring-fencing refers to situations where *legal and operational mechanisms have been deployed to insulate the utility from the potential risks posed by the parent's riskier, non-regulated activities*. Source: NYPSC. Case 23-E-0418 & 23-G-0419. Prepared testimony of Andrew Hale. January 16th, 2024. P.16.

[263] NYPSC. Case 23-E-0418 & 23-G-0419. Prepared testimony of Andrew Hale. January 16th, 2024.

[264] NYPSC. Case 23-E-0418 & 23-G-0419. Prepared testimony of Andrew Hale. January 16th, 2024. P.16.

As actual capital structure is considered, no such variance between the allowed capital structure and the actual capital structure exists.

United Kingdom

Ofgem notes that within the limits of the license conditions, *it is up to actual companies to determine their own actual capital structures* for their particular circumstances.[265] During fiscal year 2022-2023, Ofgem noticed considerable variation with actual gearing levels ranging from 52% to 70% and deviation from notional gearing levels of between -8% to +10%.[266] Nevertheless, Ofgem does not consider it *necessary to match the average gearing level of networks in each sector for the notional company to be representative of a notional efficient operator*.[267] It is for Ofgem *to set a financeable and prudent notional structure and provide reasonable allowances*, and *it would be reasonable for this to be based on other market benchmarks, not just actual networks gearing levels*.[268]

A summary of the jurisdictional review is shown in Figure 29 below.

Figure 29. Summary of the jurisdictional review (variances in actual and deemed capital structure)

Jurisdiction	Regulator's comment
Australia	Appropriate to apply a fixed benchmark over the regulatory period, irrespective of the actual gearing observed for NSPs
UK	Not necessary to match the average gearing level of networks in each sector for the notional company to be representative of a notional efficient operator
California	• The allowed capital structure is determined using the actual, most recently adopted capital structure and is fixed over the three-year cycle • As such, no variance between the allowed capital structure and the actual capital structure is considered
NY	• The allowed capital structure measured at the corporate level: o Using the actual capital structure ratio for an operating utility that is ring-fenced o Using the actual capital structure ratio of the parent company for an operating utility that is not ring-fenced • As such, no variance between the allowed capital structure and the actual capital structure is considered

265 Ofgem. RIIO-2 final determination – Finance annex (revised). February 3rd, 2021. P. 185.

266 Ofgem. RIIO-2 regulatory performance data file 2022-23. March 25th, 2024.

267 Ofgem. RIIO-2 draft determinations – Finance annex. July 9th, 2020. P.217.

268 Ibid.

4.9.3 Potential alternatives

LEI focused on the three options below:

1. **Status quo:** The OEB may continue to consider ROE and debt rates based on the deemed capital structure, allowing utilities the flexibility to adjust their actual capital structure based on their specific needs.
2. **Consider the lower of deemed equity thickness (or percentage share of equity in the capital structure) and the actual equity thickness:** For a regulated utility, equity is more expensive to finance than debt. If the actual equity share is significantly lower than the deemed share, allowing ROE on the deemed structure leads to a higher cost of capital allowance. However, the utility's debt levels will be significantly higher in such scenarios, leading to increased risk.
3. **Consider the actual utility capital structure** (subject to review during the rate case proceedings).

4.9.4 Recommendations

LEI recommends continuation of the status-quo approach (consider deemed capital structure regardless of the actual capital structure). This ensures fairness to both the utilities (flexibility to optimize the capital structure based on firm-specific needs) and the consumers (by limiting the deemed share of equity, which has a higher financing cost than debt.

If the utilities have more equity than the allowed equity in the capital structure, the equity is capped at the allowed equity thickness. If the utilities have a lower amount of equity than the allowed equity thickness, the higher share of debt makes the utility relatively riskier, justifying the ROE allowed on the excess debt proportion (deemed equity *minus* actual equity). As shown in Figure 28, this is generally not an issue in Ontario.

The level of debt on a company's books directly dictates the perceived riskiness of the utility. A relatively low equity ratio (and, in turn, a higher than optimal debt ratio) affects a utility's ability to raise financing for future investments in its rate base. This is because capital markets (and credit rating agencies) view highly leveraged companies with increasing commitments to debt repayment/debt expense as relatively riskier. This increase in perceived risk increases investors' expected return on capital and increases the overall cost of capital for the utility.

As such, assuming the same level of business risks across companies, the more debt on a particular company's books, the higher the cost of equity required/demanded by equity investors. This is also consistent with the theoretical considerations presented by Modigliani and Miller in their analysis of capital structure (see MM Proposition II in the textbox below).

Modigliani and Miller and the relationship between capital structure and firm value

On the basis of assumptions regarding perfectly ***competitive capital markets*** (with no transaction costs, taxes, bankruptcy costs or agency costs) and ***homogenous expectations*** by investors regarding a firm's cash flows, Modigliani and Miller arrived at two conclusions:

- That a firm's capital structure is irrelevant to its value, because the firm's value is derived from the discounted value of its earnings, which are available to all capital providers (The ***Capital Irrelevance Proposition or MM Proposition I***); and
- A firm's cost of equity increases proportionally as debt-financing increases, because the risk to its shareholders also rises. (The ***Cost of Equity and Leverage Proposition or MM Proposition II***).

Source: F. Modigliani and M. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," American Economic Review, Vol. 48, Issue 3, 1958.

The status quo approach is also administratively simple for the OEB while maintaining a balance of fairness for the utilities and consumers, consistent with the principles outlined by LEI in Section 3.1. As the deemed capital structures are intended to, upon application and approval, track significant changes in the sector risk profile, this also meets the FRS.

LEI recommendations - Issue 9

LEI recommends continuation of the status-quo approach (considering deemed capital structure regardless of the actual capital structure).

4.10 Return on equity – recommended revisions to existing methodology in accordance with the FRS

Issue 10: What methodology should the OEB use to produce a ***return on equity that satisfies the Fair Return Standard (FRS)***?

The OEB must legally adhere to the FRS when setting the ROE.[269] The FRS includes the following:

a) **Comparable investment standard**: a fair or reasonable return on capital should be comparable to the return available from the application of invested capital to other enterprises of like risk;

b) **Financial integrity standard**: should enable the financial integrity of the regulated enterprise to be maintained; and

c) **Capital attraction standard:** should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions**.**

[269] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009.

4.10.1 Status quo

The ROE is calculated using a base ROE of 9.75% (set in 2009) plus a LCBF spread and a utility bond spread, subject to an adjustment factor of 0.5, as shown earlier in Figure 3.[270]

The values for base ROE, base LCBF, and base utility bond spread were set as below:

$$ROE_t = 9.75\% + 0.5 \text{ x } (LCBF_t - 4.25\%) + 0.5 \text{ x } (UtilBondSpread_t - 1.415\%)$$

The OEB adjusts the ROE annually by adjusting LCBF and utility bond spread based on current data. The following are however fixed: (i) Base ROE; (ii) LCBF adjustment factor; (iii) Utility bond spread adjustment factor; (iv) base LCBF; and (v) base A-rated utility bond yield spread.

Base ROE

In EB-2009-0084, the OEB determined an LCBF of 4.25% and an ERP of 5.5%, which adds up to the Base ROE of 9.75% (4.25% + 5.5%).

The ERP was determined based on the average ERP of five participant recommendations. The participants used a mix of approaches:

i) Concentric Energy Advisors ("Concentric"), Power Advisory LLC ("Power Advisory"), Foster Associates Inc. ("Foster"), and Dr. J.H. Vander Weide used a multivariate regression analysis;
ii) Dr. J.H. Vander Weide also submitted ERP using historical stock returns (S&P/TSX utilities and BMO CM utilities stock data set) over the average bond yield (LCBF) observed during the same period;
iii) Dr. L.D. Booth submitted an ERP of 3.31% using CAPM analysis (beta of 0.5 and market risk premium of 5%);

The ERP submitted by the above participants is shown in Figure 30 below. The OEB considered the low end of the ERP submitted by the participants.

[270] Ibid.

Figure 30. Participant submissions in EB-2009-0084 proceeding with respect to ERP

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

Source: OEB.

LCBF adjustment factor

The OEB set the LCBF adjustment factor as 0.5 based on regression analysis performed by four participants in EB-2009-0084. The submissions are summarized in Figure 31. The submissions used historical data spanning 15-20 years and were generally between 0.45 to 0.5.

Figure 31. Participant submissions in EB-2009-0084 proceeding with respect to LCBF adjustment factor

Participant in in EB-2009-0084	Period of analysis	Variables used in regression analysis	LCBF adjustment factor
Dr. Vander Weide	1988-2008 (annually)	• YTM on 20-year US treasury bonds • Average allowed ROE by US regulators	-0.55
Foster	1994-2009 (quarterly)	• 30-year US government bond yields • Weighted electric and gas ROEs allowed to US utilities	0.5
Concentric	1989-2009 (quarterly)	• US government bond yields • ROEs allowed to US distribution utilities	0.45
Power Advisory	1990-2006 (annually)	• 30-year US government bond yields • ROEs allowed to US electric utilities	0.47

Source: OEB.

Utility bond spread adjustment factor

The OEB concluded from participant submissions *that there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the return on equity formula*.[271] [272]It set the utility bond spread adjustment factor as 0.5 based on regression analysis performed by three participants in EB-2009-0084. The submissions are summarized in Figure 32. The submissions used historical data spanning 15-20 years for analysis and were between 0.45 to 0.53.

Figure 32. Participant submissions in EB-2009-0084 proceeding with respect to utility bond spread adjustment factor

Participant in in EB-2009-0084	Period of analysis	Variables used in regression analysis	Utility bond spread adjustment factor
Foster	1994-2009 (quarterly)	• Moody's A-rated utility bond yields • Weighted electric and gas ROEs allowed to US utilities	0.45
Concentric	1989-2009 (quarterly)	• Moody's Corporate A-rated bond yields • Moody's Utility A-rated bond yields • ROEs allowed to US distribution utilities	0.45-0.50
Power Advisory	1990-2006 (annually)	• US Corp BAA bond yield • ROEs allowed to US electric utilities	0.53

Source: OEB.

Base LCBF and base utility bond spread

Based on September 2009 data, the OEB set the base LCBF at 4.25% and the base utility bond spread at 1.415%.

Meeting the FRS

The OEB undertook a consultative process in EB-2009-0084, and meeting the FRS was one of the key goals. The ROE formula was designed to meet the FRS primarily. The OEB stated that it *is not sufficient for a formulaic approach for determining ROE to produce a numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE it must generate a result that meets the FRS, as determined by the Board using its experience and informed judgment*.[273]

[271] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009. Page ii.

[272] LEI has reservations regarding the usefulness of this conclusion, as the cost of equity used in the regressions was a regulatory artifact rather than a market-determined variable.

[273] OEB. EB-2009-0084. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009. Page 31.

Furthermore, if the OEB ever doubts whether the FRS is being met, it retains the option to *use its discretion to begin a consultative process to determine whether circumstances warrant an adjustment to the formulaic approach, in general, or to any of the cost of capital parameter values specifically*.[274]

4.10.2 Relevant jurisdictional review

Regulators use different formulaic methodologies to set allowed ROEs: Alberta utilizes an ERP model; Australia uses a modified CAPM; and BC uses a combination of CAPM, multi-stage DCF, and ERP. Based on LEI's review, each of these regulators/jurisdictions are required to meet the FRS or adopt similar underlying principles : the AUC is governed by the legislation to *fix just and reasonable rates* for regulated utilities and *is guided in this task by well-developed case law in the meaning of just and reasonable rates*, which includes the FRS[275]; the AER sets the allowed ROE which *must contribute to the achievement of the legislative objectives*, developed following the guiding principle that states the expected rate of return should be *an unbiased estimate of the expected efficient return, consistent with the relevant risk involved in providing regulated network services*[276]; and the BCUC *is responsible for ensuring that shareholders of utilities it regulates are afforded a reasonable opportunity to earn a fair return on their invested capital*, pursuant to the Utilities Commission Act, and is guided by the FRS[277].

Alberta

The AUC sets the ROE, which is uniformly applied to all utilities and updated annually, utilizing the ERP methodology incorporating 30-year GoC bond yields and utility bond yield spread, subject to an adjustment factor of 0.5. The utility bond spread component is designed for industry-specific changes in risk, which are otherwise not captured by changes in the GoC or risk-free bond yield. The AUC initiates the generic cost of capital proceeding in early November each year, in which it provides calculations of the upcoming year's ROE based on the October data for the long-term GoC government bond forecast, and prevailing utility bond yield spread.[278]

The formula is shown in Figure 33 below.

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[274] Ibid. Page 63.

[275] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 4.

[276] AER. Rate of return instrument. Explanatory statement. February 2023. Page 52.

[277] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. Page i.

[278] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023.

Figure 33. ROE formula

$$ROE_t = \text{Base ROE } (9.0\%) + 0.5 \times (YLD_t - \text{Base YLD}) + 0.5 \times (SPRD_t - SPRD_{base})$$

Where:

- ROE_t = Return on Equity
- YLD_t = Long-term Government of Canada Bond Forecast
- Base YLD = 3.10%
- $SPRD_t$ = utility bond yield spread
- $SPRD_{base}$ = 1.58%

Source: AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023.

The long-term GoC government bond forecast (YLD_t) is calculated as the weighted average by assigning (i) 0.75 weight to the 30-year GoC bond yield forecasts of the test year published by RBC, TD, and Scotiabank in October, or the most recent month prior to October, preceding the test year; and (ii) assigning 0.25 weight to the naïve forecast, a forecasting method that uses actual values from a previous period, representing the average long-term GoC bond yield over the month of October each year preceding the test year.[279]

The prevailing utility bond yield spread ($SPRD_t$) is calculated as the average difference between the 30-year A-rated Canadian utility bond yield (Bloomberg series C29530Y) and the long-term GoC bond yield in October of the year preceding the test year.[280]

The AUC approved the risk-free rate of 3.10%, which is utilized in three ways:

(i) as a base LCBF (YLD_{base});

(ii) as a factor to determine the base ERP underlying the approved formula; and

(iii) as a measure of the risk-free rate to estimate the base ROE.

Parties unanimously considered the 30-year Canada bond yield to be default-free, and consistent with the maturity of the long-term character of the underlying utility assets, and therefore appropriate to measure the risk-free rate. The AUC agreed with utilizing the 30-year Canada bond yield and determined to use RBC, TD, and Scotiabank forecast values.

In addition to bond yield forecasts, the AUC determined to use a naïve forecast, utilizing the actual 30-year GoC bond yield to estimate the future 30-year GoC bond yield, to temper published

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279 Ibid.

280 AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023.

forecasts as they *tend to overestimate changes in interest rates*.[281] As such, the AUC set the forecast risk-free rate equal to the simple average of the LCBF for RBC, TD, and Scotiabank's forecast period of Q1 2023 to Q4 2023, as well as a naïve forecast representing the average actual long-term GoC bond yield for the month of February 2023.[282] The resulting risk-free rate is used as the base LCBF and in calculating the base forecast ERP and base ROE, which remain unchanged throughout the regulatory cycle.

The base ROE equals the sum of the base LCBF (YLD_{base}) and the base forecast ERP. Parties presented various recommendations for base ROE and ERP using various empirical models. The AUC *rejected many of these approaches and instead focused on the results of the well-known and widely used models* (CAPM, constant growth DCF, and multi-stage DCF).[283] The AUC considered results generated from the three models and determined the forecast ERP to be 5.9% and the resulting base ROE to be 9.0%. The AUC set the base forecast ERP and base ROE towards the lower end of the results, since the AUC found the risk profile of Alberta utilities is *at the lower end of the comparator group of companies.*[284] The base utility bond yield spread ($SPRD_{base}$) is calculated as the average utility bond yield spread for the month of February 2023 to be consistent with the time period selected for the risk-free rate. The resulting value is 1.58%.[285]

Furthermore, the AUC approved setting the adjustment factors for the 30-year GoC bond yield and utility bond yield spread at 0.5. Although the statistical analyses provided by parties suggested the 0.5 adjustment factor as reasonable, the AUC did not consider the analyses conclusive. Instead, the AUC *appeared to defer to the OEB adjustment factors of 0.5 for both w_1 and w_2, the latter of which is also used by the [CPUC]*.[286]

Figure 34 below shows the comparison between the OEB formula and the AUC formula. It is notable that the AUC and the OEB use the same approach with the same parameter components, however, the AUC uses a lower base ROE and base YLD (i.e. base LCBF) compared to the OEB but a higher base SPRD (i.e. base utility bond yield spread).

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[281] Ibid. Page 24.

[282] The AUC used the bank forecasts published in February 2023 as they were the most recent forecasts of long-term GoC bond yields. For consistency, it also used the average actual long-term GoC bond yield in February 2023 for the naïve forecast. A "naïve forecast" is a forecasting method that uses actual values from a previous period. Source: AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023.

[283] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 38.

[284] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 38.

[285] AUC. Decision 27084-D03-2023. Determination of the cost-of-capital parameters in 2024 and beyond – Formula base values. October 27th, 2023.

[286] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 41.

Figure 34. ROE formula Comparison – OEB vs AUC

Parameter	OEB	AUC
Base ROE	9.75%	9.00%
Base YLD	4.25%	3.10%
LCBF adjustment factor	0.5	0.5
Base SPRD	1.415%	1.580%
Utility bond yield spread adjustment factor	0.5	0.5

Note: ROE_t = Base ROE + (LCBF adjustment factor * Base YLD) + (utility bond yield spread adjustment factor * Base SPRD)

The AUC has employed the FRS in setting rates of return. The AUC noted in its 2018 GCOC decision that it *exercises its judgment in determining a total return for each utility to establish rates that provide the utility a reasonable opportunity to earn a fair return on invested capital while ensuring that rates are just and reasonable so that customers are not paying more than is required to maintain safe, reliable and economic service*.[287]

In the current 2023 GCOC proceeding, the AUC stated that a formulaic approach *could offer a substantial improvement in efficiency with no loss in rigour or objectivity in determining the ROE component of the utilities' fair return*.[288] The AUC reviewed all evidence and submissions presented by parties and applied its own judgment to determine the formula and calculate the allowed ROE *that meet the fair return standard, and result in just and reasonable rates*.[289]

Australia

The National Electricity Objective ("NEO") and the National Gas Objective ("NGO") establish the ultimate objective of the AER's decision-making, which is to promote efficient investment in and efficient operation and use of the relevant electricity or gas services for the long-term interests of consumers with respect to *price, quality, safety, reliability, and security of supply*.[290] In accordance with the objective, the AER developed the guiding principle that the expected rate of return should be *an unbiased estimate of the expected efficient return, consistent with the relevant risk involved in providing regulated network services*.[291]

287 AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 6.

288 AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 12.

289 AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 7.

290 AER. Objectives and priorities for reporting on regulated electricity and gas network performance. Final. June 2020.

291 AER. Rate of return. Assessing the long term interests of consumers position paper. May 2021. Page 1.

The AER examined that methodology of determining the allowed ROE based on eight criteria:[292]

(i) Reflective of economic and finance principles and market information;

(ii) Fit for purpose;

(iii) Implemented in accordance with good practice;

(iv) Use of quantitative modeling that is sufficiently robust and avoids arbitrary filtering or adjustment of data without a sound rationale;

(v) Information is credible and verifiable, comparable and timely, and clearly sourced;

(vi) Sufficiently flexible as to allow changing market conditions and new information to be reflected in outcomes;

(vii) Materiality of any proposed change; and

(viii) Longevity or sustainability of new arrangements.

The AER concluded that it is *justified in maintaining an unbiased approach*[293] when setting the rate of return and the instrument is most likely to *contribute to the achievement of the NEO/NGO*[294].

The AER sets an allowed ROE by utilizing the Sharpe-Lintner CAPM ("SL CAPM") approach, similar to the traditional CAPM approach, where the market risk premium ("MRP") is multiplied by the equity beta to arrive at an ERP. Then the resulting ERP is summed up with the risk-free rate using a term of 10 years to arrive at the allowed ROE (i.e. ROE = risk-free rate + beta* MRP).[295]

The AER uses the return on Commonwealth Government Securities ("CGS") with a 10-year term as the risk-free rate. The averaging period, which is the length of time during which the AER observes the return on CGS, is set between 20 and 60 business days. The nomination window, over which a regulated business can nominate its averaging period, must start and end between four months and eight months before the commencement of the regulatory period.[296]

In 2023, the AER set an MRP of 6.2% per annum over the yield to maturity on the 10-year CGS, which would be applicable for the period of 2023-2026. The AER considered evidence from historical excess return ("HER") data, dividend growth model ("DGM"), surveys, as well as other methods of estimating a forward-looking MRP, and exercised judgment to determine the value of the MRP. The HER suggested an arithmetic range of 6.1% to 6.6%, and a geometric range of 4.4% to 5.0%. While the AER placed more weight on the arithmetic returns, the geometric returns implied that the MRP is likely towards the lower end of the range given by arithmetic averages. The two-stage DGM produced an MRP between 5.5% to 5.8% over different averaging periods (2-month, 6-month, and 12-month averages), while the three-stage DGM produced an MRP

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[292] AER. Rate of return instrument. Explanatory statement. February 2023.

[293] AER. Rate of return instrument. Explanatory statement. February 2023. Page 300.

[294] AER. Rate of return instrument. Explanatory statement. February 2023. Page 302.

[295] AER. Rate of return instrument. Explanatory statement. February 2023.

[296] Ibid.

between 5.0% to 5.3%, assuming a long-run dividend growth rate of 3.85%, according to Consensus Economics. The AER also used survey results from Fermandez et al., KPMG, Asher and Hickling, and Carruther, and concluded that the most common values of MRP since 2018 have been between 6.0% to 6.3%. Considering all the information above, the AER determined that the MRP of 6.2% is *an unbiased estimate*.[297]

In addition, the AER maintained the equity beta of 0.6 from the 2018 Rate of Return Instrument as *it reflects [the AER's] gradual approach to changing parameter values consistent with empirical evidence which gives due consideration for stability and predictability that stakeholders value*.[298] The AER used regression analyses of the returns of a group of comparator companies against the overall market's return over the longest available period. The proxy group comprises Australian NSPs sharing a similar risk as the benchmark NSP. The resulting beta estimates are in the range of 0.5 to 0.6, and have been stable since 2018. Therefore, the AER decided to continue using the 2018 beta of 0.6.[299]

British Columbia

The BCUC uses a benchmark methodology where it designates a Benchmark Utility and sets the cost of capital parameters of the Benchmark Utility, and then uses the Benchmark Utility as a reference to set the cost of capital parameters of other regulated utilities by adjusting various risk factors. FortisBC Energy Inc. ("FEI") has been selected as the Benchmark Utility for natural gas utilities, while FortisBC Inc. ("FBC") has been selected as the Benchmark Utility for electric utilities.[300]

In setting the allowed ROE, the BCUC determined a proxy group consisting of publicly traded North American peer companies comparable to FEI and FBC, respectively. The BCUC also considered three financial models: CAPM, three-stage DCF, and risk premium model, and calculated the simple average of the resulting ROEs of the three models to determine the approved ROE for FEI and FBC, respectively.[301]

The comparator utilities were selected based on the following criteria:

1) *Received credit ratings of at least BBB+ from S&P or Baa1 from Moody's Investors Service ("Moody's")*
2) *Consistently pay quarterly cash dividends;*
3) *Have positive earnings growth rate projections from at least two sources;*

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[297] AER. Rate of return instrument. Explanatory statement. February 2023. Page 166.

[298] AER. Rate of return instrument. Explanatory statement. February 2023. Page 173.

[299] AER. Rate of return instrument. Explanatory statement. February 2023.

[300] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

[301] Ibid.

4) *Derive at least 65 percent (gas proxy) or 70 percent (electric proxy) of operating income from regulated operations in the period from 2018 to 2020;*
5) *Derive at least 90 percent of regulated operating income from natural gas distribution (gas proxy) or electric (electric proxy) utility service in the period from 2018 to 2020; and*
6) *Have not been involved in a merger or other significant transformative transaction during the evaluation period.*[302]

For the CAPM, the risk-free rate is based on forecast 30-year government bond yields (LCBF for Canadian utilities in each proxy group and forecast 30-year Treasury bond yields for US utilities in each proxy group). The beta for each proxy group is calculated as the average Blume-adjusted beta estimates from Value Line and Bloomberg using five years of data.

The overall MRP is calculated as the simple average of historical and forward-looking MRP estimates. The historical MRP, calculated separately for Canadian and the US markets, is based on '*the arithmetic mean of the average annual return on large companies less the return on long-term government bonds*', based on historical data from Kroll (formerly 'Duff & Phelps'). The forward-looking MRP is computed by subtracting the risk-free rate from the estimated total return of the S&P 500 Index (for the US) or the TSX (for Canada), using a constant DCF model applied to each market. Then, the overall MRP is calculated as the simple average of the historical and forward-looking Canadian MRPs and the historical and forward-looking US MRPs. The BCUC calculates the resulting ROE using the above parameters for the respective FEI and FBC proxy groups.[303]

In terms of the *three-stage DCF model*, the dividend growth rate in the first stage is based on four sources, which are SNL Financial, Value Line, Zacks, and Thomson First Call for utilities in the proxy groups; the dividend growth rate in the third stage uses the CPI forecast; and the dividend growth rate in the second stage is set on a pro-rata basis to transition from the first stage to the third stage. Finally, combined with the above parameters, the DCF model uses each proxy group's 30-day average stock prices and 30-day average dividend yields in October 2022 to calculate the resulting ROEs for FEI and FBC.[304]

The *risk premium model* estimates the cost of equity as the sum of the ERP and the return on a particular class of bonds. The BCUC performs a regression analysis annually to examine the relationship between the historical allowed ROEs and the 30-day average yield on the 30-year Treasury bond based on data from October of the preceding year (so October 2022 for estimating 2023 values and so on) for US electric and gas utilities, respectively. The analysis is performed on US data only due to the inadequacy of Canadian data in BCUC's view. Further, the BCUC uses a five-year forecast bond yields of the 30-year Treasury bond to calculate the ERP, and the resulting ROE for US gas utilities (FEI's proxy group) and US electric utilities (FBC's proxy group), respectively.

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[302] Ibid. Page 9.

[303] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

[304] Ibid.

Furthermore, the BCUC is guided by the FRS where it has *a duty to approve rates that will provide the utilities' shareholders a reasonable opportunity to earn a fair return on their invested capital*.[305] The BCUC evaluated the evidence presented by experts and interveners in terms of comparable proxy peers and financial models, along with FEI and FBC's respective business risks and credit ratings.

BCUC's informed judgment and quantitative and qualitative evidence play *a significant role in determining the appropriate cost of capital for each of the two utilities*.[306] In particular, it stated the need to use multiple financial models to mitigate each model's inherent drawbacks in determining a fair return. Based on the evidence examined and submissions received in the GCOC proceeding, the BCUC concluded that the allowed ROE would *meet the Fair Return Standard*.[307]

A summary of the jurisdictional review is shown below.

Figure 35. Summary of the jurisdictional review (ROE determination)

Jurisdiction	Approach to determining allowed ROE	Description
Alberta	Formulaic	• ROE_t = Base ROE+ 0.5 x (YLD_t – YLD_{base}) + 0.5 x ($SPRD_t$ – $SPRD_{base}$) • Risk-free rate is set at 3.1%, equal to the simple average of the LCBF for RBC, TD, and Scotiabank's forecast period of Q1 2023 to Q4 2023, as well as a naïve forecast for the average actual long-term GoC bond yield for the month of February 2023 • Base ROE is set at 9.0% and equal to the risk-free rate (3.1%) plus the base forecast ERP (5.9%); ERP is determined based on results from the CAPM, constant growth DCF, and multi-stage DCF • YLD_t is the weighted average of 30-year GoC bond forecasts of the test year published by RBC, TD, and Scotiabank (0.75 weight) and the naïve forecast of the average historical long-term GoC bond yield (0.25 weight) • YLD_{base} is equal to the risk-free rate of 3.1% • $SPRD_t$ is the average difference between the 30-year A-rated Canadian utility bond yield and the long-term GoC bond yield • $SPRD_{base}$ is set at 1.58%, calculated as the average utility bond yield spread for the month of February 2023 • The adjustment factors of 0.5 are deferred to the OEB's and the CPUC's practices
Australia	Formulaic	• ROE_t = MRP x beta + risk-free rate • MRP is set at 6.2% based on HER data, DGM, surveys, and the AER's own judgement • Beta is set at 0.6 based on regression analyses of the returns of a proxy group against the overall market return • Risk-free rate is set at 3.6% based on the return on 10-year CGS with an averaging period between 20 and 60 business days determined by NSPs within the nomination window
British Columbia	Benchmark	• Determine a proxy group for FEI and FBC each based on certain screening criteria • Calculate ROEs using the CAPM, three-stage DCF model, and risk premium model for each proxy group • The simple average of the resulting ROEs of the three model is the allowed ROE for FEI/FBC

4.10.3 Potential alternatives

LEI has presented potential alternatives separately for determining the ROE and the frequency of updating the ROE.

[305] Ibid. Page 5.

[306] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. Page 6.

[307] Ibid. Page v.

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 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.

Figure 37. Determination of DCF ROE for electricity generation, wires (electricity transmission/distribution) and gas transmission/distribution

Generation			
Company	**Dividend yield (Apr 2023 - Mar 2024)**	**2024-2026 annual EPS growth estimate**	**DCF ROE**
Boralex Inc. (TSX:BLX)	2.1%	5.9%	7.9%
Constellation Energy Corporation (NASDAQGS:CEG)	0.7%	13.2%	13.8%
NRG Energy, Inc. (NYSE:NRG)	2.0%	3.6%	5.6%
Ormat Technologies, Inc. (NYSE:ORA)	0.7%	15.3%	16.0%
Vistra Corp. (NYSE:VST)	0.9%	13.4%	14.3%
Average	**1.26%**	**10.26%**	**11.52%**

Wires (electricity transmission and distribution)			
Company	**Dividend yield (Apr 2023 - Mar 2024)**	**2024-2026 annual EPS growth estimate**	**DCF ROE**
Ameren Corporation (NYSE:AEE)	3.7%	6.1%	9.8%
Consolidated Edison, Inc. (NYSE:ED)	3.4%	5.1%	8.5%
Edison International (NYSE:EIX)	4.1%	8.7%	12.8%
Eversource Energy (NYSE:ES)	4.7%	5.5%	10.1%
Exelon Corporation (NASDAQGS:EXC)	3.9%	5.4%	9.4%
FirstEnergy Corp. (NYSE:FE)	4.2%	6.5%	10.7%
Hydro One Limited (TSX:H)	3.1%	6.1%	9.2%
National Grid plc (LSE:NG.)	5.0%	6.2%	11.2%
NorthWestern Energy Group, Inc. (NASDAQGS:NWE)	5.0%	8.1%	13.1%
Average	**4.12%**	**6.41%**	**10.53%**

Gas distribution			
Company	**Dividend yield (Apr 2023 - Mar 2024)**	**2024-2026 annual EPS growth estimate**	**DCF ROE**
AltaGas Ltd. (TSX:ALA)	3.9%	10.3%	14.2%
Atmos Energy Corporation (NYSE:ATO)	2.7%	8.0%	10.7%
Chesapeake Utilities Corporation (NYSE:CPK)	2.3%	9.0%	11.3%
Enbridge Inc. (TSX:ENB)	7.3%	5.7%	13.0%
New Jersey Resources Corporation (NYSE:NJR)	4.0%	4.3%	8.2%
Northwest Natural Holding Company (NYSE:NWN)	5.1%	3.5%	8.5%
ONE Gas, Inc. (NYSE:OGS)	4.1%	3.1%	7.2%
RGC Resources, Inc. (NASDAQGM:RGCO)	3.9%	7.9%	11.8%
Spire Inc. (NYSE:SR)	4.8%	5.3%	10.2%
Average	**4.22%**	**6.34%**	**10.56%**

Note: 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.

Source: S&P Capital IQ.

To determine a uniform ROE for all OEB-regulated entities, LEI assigned weights (to estimates above) based on the sector's respective share of the 2022 rate base for the OEB-regulated entities.

For example, the 'electricity transmission and distribution' sector's share of the rate base relative to the total rate base across the three regulated sectors is 55%.

This approach resulted in a weighted average DCF ROE of 10.77% (as presented in Figure 38 below).

Figure 38. Determination of uniform DCF ROE for OEB-regulated entities

Utility industry sector	Share of 2022 rate base in Ontario	DCF ROE
Electricity transmission and distribution	55%	10.53%
Electricity generation	24%	11.52%
Natural gas distribution	22%	10.56%
Weighted average DCF ROE		**10.77%**

3. Same as #1 but determination of adjustment factors using multivariate regression analysis

The OEB (based on participant submissions in EB-2009-0084) determined the LCBF adjustment factor and the utility bond spread adjustment factor independently using distinct regression analysis. However, the credit spreads and central bank interest rates (which affect government bond yields) are intrinsically linked.[309] In the short run, a rise in Treasury rates is associated with declining credit spreads. However, a rise in Treasury rates may increase credit spreads in the long run. As such, it is reasonable to consider the impacts of BoC bond yields and corporate bond spreads on allowed ROEs within the same regression equation.

Considering the two variables simultaneously (the weighted average ROEs allowed by US regulators for electric and gas utilities as the dependent variable; 30-year US Treasury 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. The multivariate regression analysis performed by LEI had an R squared value of 0.61, which indicates that a reasonably high amount of variance in the dependent variable (allowed ROEs) has been explained by the variance in dependent variables since 2001.

4. Determination of base ROE and annual adjustment of ROE using CAPM

The ROE with CAPM is estimated through the following formula:

Return on equity = risk-free rate + (beta x market risk premium) + additional risk premium (optional)

where:

- the *risk-free rate* measures a return available on an investment that is guaranteed and is uncorrelated with risky investments in a market;

[309] Charles S. Morris & Robert Neal & Doug Rolph, 1998. "Credit spreads and interest rates : a cointegration approach," Research Working Paper 98-08, Federal Reserve Bank of Kansas City.

- *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.

Figure 39. Determination of beta for electricity generation, wires (electricity transmission/distribution) and gas transmission/distribution

Generation

Unlevered Beta		**Ontario**		**Re-levered Beta**	
Average (1-yr)	0.45	D/E	1.46	Average (1-yr)	0.93
Average (3-yr)	0.30	Tax Rate	26.5%	Average (3-yr)	0.62
Average (5-yr)	0.31			Average (5-yr)	0.64

Country	Company Name	Levered/Raw Beta (1 yr.)	Levered/Raw Beta (3 yr.)	Levered/Raw Beta (5 yr.)	Debt/ Equity	Tax Rate	Unlevered Beta (1 yr.)	Unlevered Beta (3 yr.)	Unlevered Beta (5 yr.)
CA-QC	Boralex Inc. (TSX:BLX)	1.12	0.64	0.66	2.28	26.5%	0.42	0.24	0.25
US	Brookfield Renewable Corporation (TSX:E	1.09	0.72	0.44	0.93	21.0%	0.63	0.42	0.25
US	Clearway Energy, Inc. (NYSE:CWEN.A)	1.15	0.85	0.87	2.03	21.0%	0.44	0.33	0.33
US	Constellation Energy Corporation (NASD.	0.98			0.74	21.0%	0.62		
CA-QC	Innergex Renewable Energy Inc. (TSX:INE	1.77	0.82	0.90	4.41	26.5%	0.42	0.19	0.21
CA-ON	Northland Power Inc. (TSX:NPI)	1.15	0.64	0.60	1.97	26.5%	0.47	0.26	0.25
US	NRG Energy, Inc. (NYSE:NRG)	0.77	0.83	0.93	2.75	21.0%	0.24	0.26	0.29
US	Ormat Technologies, Inc. (NYSE:ORA)	0.98	0.84	0.86	0.95	21.0%	0.56	0.48	0.49
CA-AB	TransAlta Corporation (TSX:TA)	1.00	0.58	0.97	2.10	23.0%	0.38	0.22	0.37
US	Vistra Corp. (NYSE:VST)	0.87	0.83	0.87	2.29	21.0%	0.31	0.30	0.31
Average		1.09	0.75	0.79	2.04	22.9%	0.45	0.30	0.31

Wires (electricity transmission and distribution)

Unlevered Beta		**Ontario**		**Re-levered Beta**	
Average (1-yr)	0.24	D/E	1.50	Average (1-yr)	0.49
Average (3-yr)	0.21	Tax Rate	26.5%	Average (3-yr)	0.44
Average (5-yr)	0.32			Average (5-yr)	0.67

Country	Company Name	Levered/Raw Beta (1 yr.)	Levered/Raw Beta (3 yr.)	Levered/Raw Beta (5 yr.)	Debt/ Equity	Tax Rate	Unlevered Beta (1 yr.)	Unlevered Beta (3 yr.)	Unlevered Beta (5 yr.)
US	Ameren Corporation (NYSE:AEE)	0.36	0.47	0.68	1.41	21.0%	0.17	0.22	0.32
US	Consolidated Edison, Inc. (NYSE:ED)	0.28	0.37	0.52	1.20	21.0%	0.14	0.19	0.27
US	Edison International (NYSE:EIX)	0.57	0.62	0.80	1.84	21.0%	0.23	0.25	0.33
US	Eversource Energy (NYSE:ES)	0.62	0.51	0.70	1.58	21.0%	0.28	0.23	0.31
US	Exelon Corporation (NASDAQGS:EXC)	0.39	0.51	0.87	1.45	21.0%	0.18	0.24	0.41
US	FirstEnergy Corp. (NYSE:FE)	0.41	0.49	0.76	2.38	21.0%	0.14	0.17	0.26
CA-ON	Hydro One Limited (TSX:H)	0.79	0.34	0.54	1.34	26.5%	0.40	0.17	0.27
US	National Grid plc (NYSE:NGG)			0.63	1.68	21.0%			0.27
US	NorthWestern Energy Group, Inc. (NASD.	0.63	0.44	0.81	1.03	21.0%	0.35	0.24	0.45
Average		0.51	0.47	0.70	1.55	0.22	0.24	0.21	0.32

Gas distribution

Unlevered Beta		**Ontario**		**Re-levered Beta**	
Average (1-yr)	0.30	D/E	1.63	Average (1-yr)	0.62
Average (3-yr)	0.27	Tax Rate	26.5%	Average (3-yr)	0.55
Average (5-yr)	0.38			Average (5-yr)	0.79

Country	Company Name	Levered/Raw Beta (1 yr.)	Levered/Raw Beta (3 yr.)	Levered/Raw Beta (5 yr.)	Debt/ Equity	Tax Rate	Unlevered Beta (1 yr.)	Unlevered Beta (3 yr.)	Unlevered Beta (5 yr.)
CA-AB	AltaGas Ltd. (TSX:ALA)	0.85	0.83	1.32	1.25	23.0%	0.44	0.42	0.67
US	Atmos Energy Corporation (NYSE:ATO)	0.41	0.50	0.66	0.83	21.0%	0.25	0.30	0.40
US	Chesapeake Utilities Corporation (NYSE:C	0.61	0.49	0.78	1.05	21.0%	0.34	0.27	0.43
CA-AB	Enbridge Inc. (TSX:ENB)	0.78	0.80	1.12	1.26	23.0%	0.40	0.40	0.57
US	New Jersey Resources Corporation (NYSE	0.48	0.54	0.89	1.69	21.0%	0.21	0.23	0.38
US	Northwest Natural Holding Company (NY	0.48	0.44	0.80	1.47	21.0%	0.22	0.21	0.37
US	ONE Gas, Inc. (NYSE:OGS)	0.48	0.46		1.38	21.0%	0.23	0.22	0.00
US	RGC Resources, Inc. (NASDAQGM:RGCC	0.84	0.29	0.51	1.43	21.0%	0.39	0.13	0.24
US	Spire Inc. (NYSE:SR)	0.49	0.47	0.74	1.52	21.0%	0.22	0.21	0.34
Average		0.60	0.54	0.85	1.32	0.21	0.30	0.27	0.38

Notes: (i) 1-year and 3-year betas are obtained from S&P Capital IQ; (ii) LEI has computed the 5-year beta by assessing the correlation of daily company stock returns against the relevant daily index returns (S&P 500 for US companies and S&P/TSX composite index for Canadian companies) for the 5-year period from 2019 to 2023.

Sources: S&P Capital IQ, Yahoo Finance.; LEI analysis.

To determine a uniform beta for all OEB-regulated entities, similar to the methodology for determining a uniform/weighted average ROE in alternative #2, LEI assigned weights based on the share of the 2022 rate base for the OEB-regulated entities (see Figure 40 below).

This approach resulted in re-levered 1-year, 3-year, and 5-year weighted average betas of 0.62, 0.51 and 0.69, respectively.[310]

Figure 40. Determination of uniform beta for OEB-regulated entities

Utility industry sector	Share of 2022 rate base in Ontario	Re-levered 1-yr beta	Re-levered 3-yr beta	Re-levered 5-yr beta
Electricity transmission and distribution	55%	0.49	0.44	0.67
Electricity generation	24%	0.93	0.62	0.64
Natural gas distribution	22%	0.62	0.55	0.79
Weighted average beta		**0.62**	**0.51**	**0.69**

A ***risk-free rate*** implies a return available on an investment that is guaranteed and uncorrelated with risky investments in a market.[311] For an investment to be considered risk-free, there must be near-zero default and reinvestment risks.[312]

It is relatively straightforward to select a proxy for a virtually default-free investment by reviewing its historical performance. Sovereign government bonds issued by the US and Canada are considered good proxies for default-free investments.

To reduce reinvestment risk, a practical compromise is to match the cash flows from the investment asset with an equivalent liability issued by the subject entity.[313] As such, LCBF forecasts continue to be a reasonable proxy for risk-free rates. For reasons provided in Section 4.7.2, LEI recommends considering publicly available reputable sources (such as average forecasts from major Canadian banks) for 30-year bond forecasts for LCBF/risk-free rate. As presented earlier in Figure 26, this approach results in the average forecast yield for 2025 to be 3.19%.

The ***MRP*** measures what investors demand as an extra return for investing in a portfolio relative to the risk-free asset for undertaking additional risk. A forward-looking MRP forecast is trickier as market returns can be highly volatile from year to year, and considering forecasts for a 3-5 year period may not represent the average market returns that investors accept. As such, analyzing the historical spread between the risk-free rate and the market returns is a commonly used

[310] For comparison, LEI reviewed the average levered 1-year and 3-year betas for 39 publicly traded North American utilities (companies included in LEI peer groups were not considered for this analysis). As of May 2024, the average levered 1-year beta and 3-year beta is 0.50. Source: S&P Capital IQ.

[311] Aswath Damodaran. Stern School of Business, New York University. What is the risk free rate? A Search for the Basic Building Block. December 2008.

[312] Ibid.

[313] Ibid.

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.

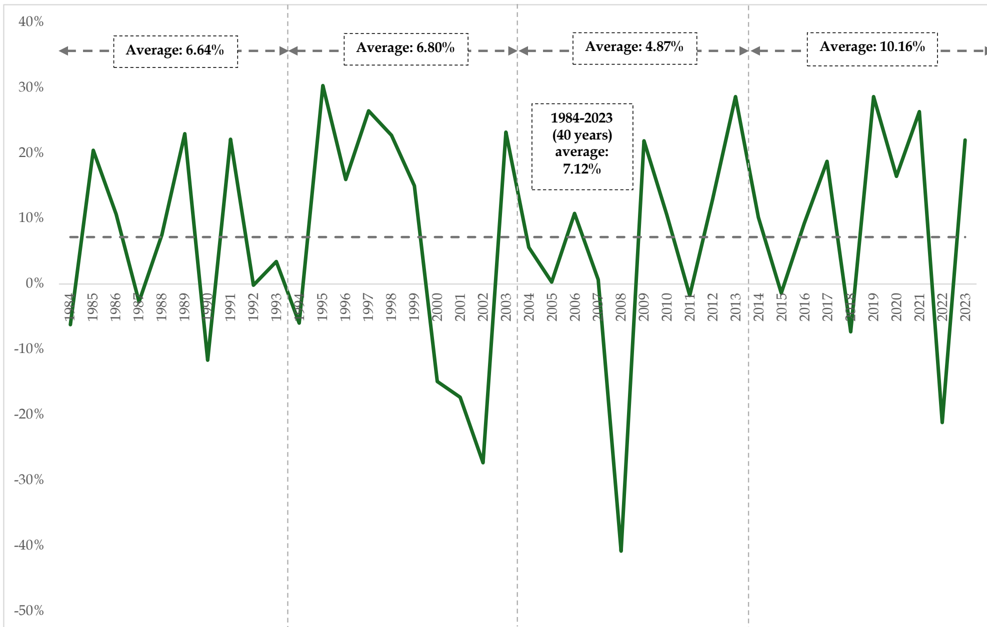
LEI believes that CAPM ROE based on Canadian market data (5.14%) does not reflect investors' expected equity returns. The eight major pension funds in Canada (informally known as the Maple 8) allocate only about 25% of their portfolio to domestic Canadian investments, which indicates that investors are 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).

[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.

Figure 42. US MRP (1984 – 2023)

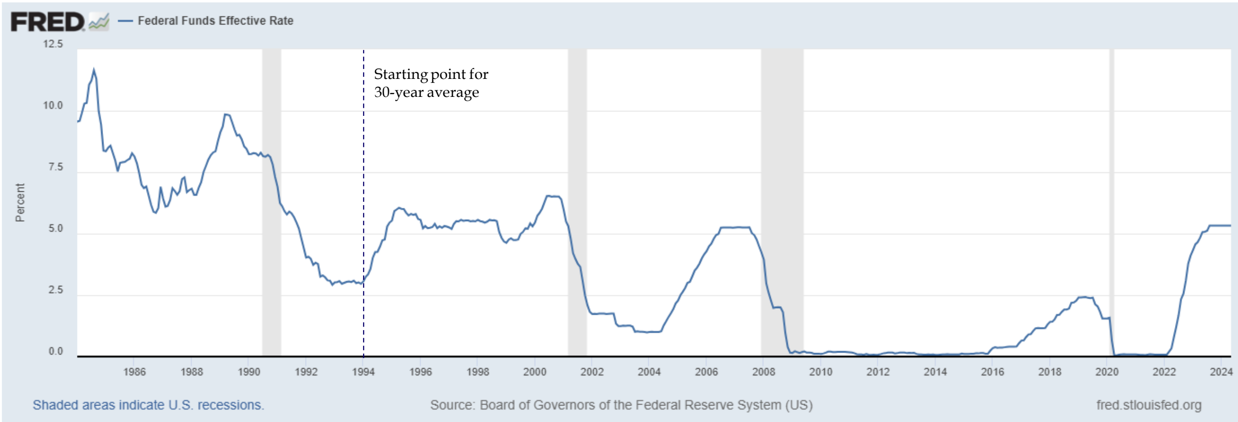


Source: S&P Capital IQ.

The investor expectations of MRP may be shaped by the high US market returns observed during the last 10 years. However, the current macroeconomic environment has more similarities to the macroeconomic environments observed during the 1990s and the 2000s. For instance, the prevailing interest rate environment aligns more with the Federal Reserve ("Fed") policy rates observed in the 1990s and 2000s (see Figure 43 below).[316] This is further complicated by the expectation of policy rate cuts over the coming years, albeit the policy rates are not expected to decline to levels observed in the 2010s. LEI, therefore, considers CAPM ROE computed using 10-year, 20-year, and 30-year market data to be valid and reasonable. This provides a high CAPM ROE estimate of 10.22% (shaded in green in Figure 41), a low CAPM ROE estimate of 8.23% (shaded in green in Figure 41), and an average CAPM ROE estimate of 8.95%, which implies an average ERP of 5.75%. This average ERP estimate provides more weightage to recent 2014-2023 data.

[316] The annual GDP growth rates and the unemployment rates observed since 2021 also align more strongly with those observed during the 1990s and 2000s (rather than the 2010s).

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.

annually with the current ROE formula using adjustment factors determined in alternative #3, i.e., 0.26 for the LCBF adjustment factor and 0.13 for the utility bond spread adjustment factor.

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:

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

Figure 44. Determination of base utility bond spread

Month: March 2024

		Bond Yields %		Bond Yield Spreads %
	Day	Govt. of Canada 30-yr	A-rated Utility 30-yr	30-yr. Util. over 30-yr Govt.
1	1-Mar-24	3.32	4.66	1.34
2	2-Mar-24			
3	3-Mar-24			
4	4-Mar-24	3.34	4.70	1.36
5	5-Mar-24	3.25	4.62	1.37
6	6-Mar-24	3.23	4.61	1.38
7	7-Mar-24	3.25	4.62	1.37
8	8-Mar-24	3.24	4.62	1.38
9	9-Mar-24			
10	10-Mar-24			
11	11-Mar-24	3.27	4.65	1.38
12	12-Mar-24	3.30	4.70	1.40
13	13-Mar-24	3.33	4.72	1.39
14	14-Mar-24	3.40	4.80	1.40
15	15-Mar-24	3.40	4.81	1.41
16	16-Mar-24			
17	17-Mar-24			
18	18-Mar-24	3.46	4.85	1.39
19	19-Mar-24	3.42	4.82	1.40
20	20-Mar-24	3.40	4.80	1.40
21	21-Mar-24	3.43	4.82	1.39
22	22-Mar-24	3.37	4.75	1.38
23	23-Mar-24			
24	24-Mar-24			
25	25-Mar-24	3.40	4.79	1.39
26	26-Mar-24	3.40	4.80	1.40
27	27-Mar-24	3.35	4.74	1.39
28	28-Mar-24	3.34	4.75	1.41
29	29-Mar-24			
30	30-Mar-24			
31	31-Mar-24			
		3.345	**4.730**	**1.385**
	Sources:	Bank of Canada	Bloomberg	

Sources: Bank of Canada, Bloomberg.

6. Determination of an average base ROE from CAPM, ERP and DCF methodologies, with annual updating of ROE based on #3

To determine base ROE, the OEB can also consider the average ROE from different methodologies (CAPM, DCF and ERP methodologies) to reduce the overreliance on a single methodology. Although international jurisdictions reviewed by LEI rely on CAPM to determine ROE (Australia and the UK), LEI acknowledges that most North American jurisdictions consider a mix of ROE methodologies. A summary of methodologies used in other jurisdictions is shown in Figure 45 below.

Figure 45. ROE methodologies used in other jurisdictions

Jurisdiction	CAPM	DCF	ERP	CE*	Combined
Alberta			x		
Australia	x				
British Columbia					x (CAPM, DCF, and ERP)
California					x (CAPM, DCF, and ERP)
Federal Energy Regulatory Commission					x (CAPM, DCF, and ERP)
Florida					x (CAPM and DCF)
Georgia					x (CAPM, DCF, ERP, and CE)
Illinois					x (CAPM and DCF)
Michigan					x (CAPM, DCF, and ERP)
New York					x (CAPM and DCF)
North Carolina					x (CAPM, DCF, and ERP)
Ohio					x (CAPM and DCF)
Ontario			x		
Pennsylvania					x (CAPM and DCF)
Texas					x (DCF and ERP)
United Kingdom	x				

* CE stands for 'Comparable Earnings' approach.

Sources: S&P Capital IQ, past rate cases.

This results in a base ROE of 9.60%, which is an average of 8.95% (CAPM approach), 10.77% (DCF approach), and 9.09% (ERP approach). The ROE can be updated annually based on the formula described in alternative #5.

The results from the options presented by LEI are summarized in Figure 46 below.

Figure 46. Summary of ROE options

Alternative #	Description	Base ROE value	LCBF adjustment factor	Corporate bond yield spread adjustment factor
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	9.09%	0.39	0.33
2	Same as #1 except determining base ROE with the discounted cash flow ("DCF") approach instead of the ERP approach	10.77%	0.39	0.33
3	Same as #1 but determination of adjustment factors using multivariate regression analysis	9.09%	0.26	0.13
4	Determination of base ROE using CAPM and adjustment of ROE using CAPM formula parameters	**Average: 8.95%** High: 10.22% Low: 8.23%	N/A	N/A
5	Determination of base ROE using CAPM, with ROE updated using adjustment factors determined in #3	**Average: 8.95%** High: 10.22% Low: 8.23%	0.26	0.13
6	Determination of an average base ROE from CAPM, ERP and DCF methodologies, with updating of ROE based on #3	9.60%	0.26	0.13

Notes:

(i) LEI recommended alternative is highlighted.

(ii) The ROEs allowed by US regulators in 2022 and 2023 rate cases have ranged between 7.85% and 11.45% (Source: S&P Capital IQ).

(iii) For each alternative presented above, the base ROE value and adjustment factors are to be updated after five years; $LCBF_t$ is to be updated annually in October/November of every year as per the methodology described in Figure 26 (latest 30-year GoC bond yield forecasts for the subsequent year from major Canadian banks); $UtilBondSpread_t$ is to be updated annually in October/November of every year based on the 12-month average (data from October of the previous year to September of the current year) for the BVCAUA30 BVLI Index.

Potential alternatives for frequency of updating ROE

The OEB may consider the following options for updating ROE:

1. **Status quo:** ROE is updated annually using a formulaic approach. The prevailing ROE during the year of rate case filing is applicable for the entire IRM period.

2. **Set ROE for the five upcoming years** and update the ROE every five years (for the next five years) based on new data.

4.10.4 Recommendations

LEI prefers to use CAPM for base ROE determination (alternative #5). Beta is a useful indicator in measuring sector-specific risk (which the ERP methodology lacks). Due to the stable returns allowed by regulators, the regulated utility industry is a relatively low-risk industry.[319] A beta is necessary to determine the appropriate ERP for regulated utilities. CAPM, when used judiciously, also meets the FRS as the ERP is determined specifically to compensate for additional risk over the risk-free rate.

A key issue with the DCF (constant growth and multi-growth) approach to estimating ROE is that it primarily relies on subjective future earnings growth estimates. Furthermore, DCF and risk premium methodologies are less used by actual investors to estimate ROE outside of regulatory proceedings.

While LEI acknowledges that the DCF method is sometimes used for determining ROE, its reliance upon estimates of future growth of cash flows is a key weakness, as it relies entirely on growth yield estimates, which typically tend to overestimate the ROE. Estimates of future growth of cash flows can be unreliable: studies 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.[320] Earnings forecasts can be inaccurate, tend to overvalue the cost of equity, and are consistently overly optimistic.[321] While the DCF methodology is a very widely used tool for valuing a company, the target ROE is an input rather than an output. When valuing a company or an asset using DCF methodology, a terminal value is frequently considered to capture the value of a business beyond the projection period (typically 10 to 30 years) in a DCF analysis. As such, DCF methodology is poorly suited for ROE determination using only a 3-5 years forward-looking outlook and is likely to result in an unrepresentative estimate of the ROE.

LEI believes that using CAPM to estimate ROE is the most reasonable method because it is among the most commonly used valuation methods, with a widespread understanding of the assumptions/inputs involved and the ability to adjust results to account for unsystematic or company-specific risks.[322]

CAPM takes the systematic risk, i.e., the risk inherent in the market, into account through empirical analysis of historical data. While it is true that CAPM relies on the quality of input data and assumptions, reliance on a well-defined range from a historical dataset is a sensible approach

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[319] S&P Global Ratings classifies regulated utilities as a 'low risk' sector in cyclicality assessment and as 'very low risk' in competitive risk and growth environment assessment, as well as global industry risk assessment. Source: S&P Global Ratings. Updated: January 25th, 2021.

[320] Michael Lacina, B. Brian Lee and Zhao Xu, *Advances in Business and Management Forecasting*, at 77–101 (Kenneth D. Lawrence, Ronald K. Klimberg eds., Emerald Grp. Publ'g Ltd. 2011).

[321] R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts." *Journal of Business Fin. & Accounting*, 725–55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan. "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings." *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates." *Journal of Finance.* 643−84 (2003).

[322] Bruner, Robert & Eades, Kenneth & Harris, Robert & Higgins, Robert. (1998). Best Practices in Estimating the Cost of Capital: Survey and Synthesis. Financial Practice and Education. 8.

relative to other alternatives, such as estimating risk premium based on assumptions of future earnings growth.

With respect to annual updating, alternative #5 (determination of an average base ROE from CAPM combined with annual updating of ROE using adjustment factors based on #3), is similar to the current methodology of updating the ROE, which has responded reasonably well to changes in macroeconomic conditions since 2009 while minimizing volatility (the allowed ROE has stayed in the range of 8.34% to 9.85%). As such, there are no material benefits to changing the status quo approach.

LEI recommendations - Issue 10

- LEI recommends using 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 can 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).

4.11 Return on equity – relevance and consideration of debt and equity investor perspectives

Issue 11 is described in the text box below.

Issue 11: ***Are the perspectives of debt and equity investors in the utility sector relevant*** to the setting of cost of capital parameters and capital structure? If yes, ***what are the perspectives relevant to that consideration***, and ***how should those perspectives be taken into account*** for setting cost of capital parameters and capital structure?

4.11.1 Status quo

OEB's existing cost of capital methodologies explicitly consider equity and debt investor perspectives. The allowed ROEs are legally required to meet the FRS. The FRS inherently requires sufficient returns for the commensurate risk undertaken by the investors and ensure that the utilities continue to attract incremental capital at reasonable terms. The DLTDR and DSTDR formulas are formulated considering OEB-regulated entities' credit profiles (as set by the credit rating agencies).

OEB is also among the few North American regulators to annually update the cost of capital parameters to ensure they align with the current macroeconomic environment. As such, LEI is not aware of OEB-regulated entities facing notable issues in attracting equity and debt capital since 2009.[323] This is also reflected in the utility credit ratings and the regulator assessments

[323] There have been numerous recent successful bond issuances by OEB-regulated utilities. Since 2021, Enbridge Gas has had seven successful issuances of its corporate bond/note, amounting to $2.55 billion; Hydro One has had

performed by the credit rating agencies. For instance, S&P Global assesses the US and Canadian regulatory regimes based on analysis of quantitative and qualitative factors such as regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation.[324]

Based on its assessment, S&P groups US states and Canadian provinces into 5 categories: (i) credit supportive; (ii) more credit supportive; (iii) very credit supportive; (iv) highly credit supportive; and (v) most credit supportive.

In its November 2023 assessment, S&P classified the Province of Ontario and two other Canadian provinces as 'most credit supportive', as can be seen in the following figure.[325]

ten successful issuances, amounting to $4.83 billion; OPG has had five successful issuances, amounting to $1.63 billion; and Toronto Hydro has had five successful issuances, amounting to $1.1 billion. Source: S&P Capital IQ.

[324] S&P Global Ratings. U.S. And Canadian Utility Regulatory Updates And Insights: June 2020.

[325] S&P Global Ratings. North American Utility Regulatory Jurisdictions: Some Notable Developments. November 10th, 2023.

Figure 47. Utility regulatory jurisdiction assessment performed by S&P Global (updated November 2023)

Credit supportive (adequate)	More credit supportive (strong/adequate)	Very credit supportive (strong/adequate)	Highly credit supportive (strong/adequate)	Most credit supportive (strong)
New Mexico	Alaska	Colorado	Alberta	Alabama
Nova Scotia	Arizona	Delaware	Arkansas	British Columbia
Prince Edward Island	California	Idaho	Georgia	Federal Energy Regulatory Commission (electric)
	Connecticut	Illinois	Indiana	Florida
	District of Columbia	Maryland	Kansas	Iowa
	Hawaii	Missouri	Louisiana	Kentucky
	Montana	Mississippi	Maine	Michigan
	New Jersey	Nebraska	Massachusetts	Ontario
	New Orleans	Nevada	Minnesota	Quebec
	Oregon	New York	North Carolina	Wisconsin
	South Carolina	Ohio	New Hampshire	
		Oklahoma	Newfoundland & Labrador	
		Rhode Island	North Dakota	
		South Dakota	Pennsylvania	
		Texas	Tennessee	
		Vermont	Texas RRC	
		Washington	Utah	
		West Virginia	Virginia	
		Wyoming		

RRC--Railroad Commission of Texas. Source: S&P Global Ratings.

Source: S&P Global.

DBRS considers the regulatory regime in Ontario to be one of the key strengths in its rating considerations. For instance, in its recent November 2023 credit rating for Hydro One, it stated that the OEB's regulatory regime permits Hydro One *a reasonable opportunity to recover operating and capital costs, and to earn the approved return on equity (ROE)*. Further, it *views the utility regulatory framework in Ontario as transparent and supportive for regulated transmission and distribution operators*.[326]

4.11.2 Relevant jurisdictional review

Alberta, BC, and the UK consider investors' perspectives relevant to setting cost of capital parameters and capital structure. In particular, investors' expectations of market conditions, perceptions of business risks, and perspectives on whether the return on capital meets the financial integrity and capital attraction requirements are considered and reflected in setting these parameters and structures.

[326] DBRS Morningstar. Rating Report: Hydro One Limited. November 20th, 2023.

Alberta

The AUC considers investors' perspectives relevant to setting cost-of-capital parameters and capital structure, including their expectations of market conditions, perceptions of macroeconomic risks, financial integrity, and capital attraction.

The AUC considers credit metrics when evaluating the appropriateness of the deemed capital structure. It recognizes that the process of setting credit metrics required to maintain an A-range credit rating for utilities is *a function of market dynamics and credit agency analysis of macro-economic trends, Canadian utility industry specific variables, and future investor expectations, applied to an assessment of the relative risk of the utility sector, and perceptions of the regulatory environment*.[327] Moreover, credit metrics influence investors' risk perceptions, and consequently, may influence market behavior. Therefore, the AUC considers *the credit metrics reflected in credit rating and market analyst reports to be generally reflective of future expectations of utility debt and of equity investors with respect to credit metric fundamentals*.[328]

When evaluating macroeconomic changes since the 2018 GCOC decision, the AUC notes that the increasing credit spread between A-rated utilities and government bonds demonstrates *investors' concerns about the macroeconomic conditions for utilities*, and *[c]apital market volatility, although having moderated recently, could flare up again until investors are once again confident that conditions have stabilized*.[329]

Although the AUC acknowledges that there has been a deterioration in macroeconomic conditions since 2018, Alberta's supportive regulatory environment can protect utilities from rising costs associated with adverse macroeconomic changes, which is demonstrated by *robust returns* achieved by Alberta utilities between 2020 and 2022.[330]

Furthermore, investors' perspectives play an important role when determining if financial integrity and capital attraction under the FRS have been met. The AUC notes that investors should be able to earn sufficient revenue to recover capital costs and operating costs associated with the business, as well as be able to service the debt and pay dividends on the stock. Overall, the return should be *sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital*.[331]

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[327] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. P.49.

[328] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. P.50.

[329] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. P.8.

[330] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. P.9.

[331] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. P.5.

British Columbia

The BCUC also considers investors' perspectives relevant to setting cost of capital parameters and capital structure with respect to their expectations of the business environment and perceptions of risks.

The BCUC recognizes the impact of business risk on utilities' expected return, and thus reviews the risk from shareholders' perspectives as *it is an important consideration for investors when making their investment decisions*.[332]

The BCUC also acknowledges that debt and equity investors view credit ratings as reflective of rating agencies' assessment of the riskiness of their investments. As such, lowering credit ratings may raise concerns for potential investors regarding the utilities' access to the credit market at reasonable costs. Thus, the BCUC establishes an ROE and capital structure which *will allow for the utilities' existing credit agency ratings to be maintained and avoid eroding each utility's ability to access capital at reasonable cost[s]*.[333]

The BCUC, when setting the allowed ROE, utilizes the DCF model, which considers investors' perspectives, and is based on the premise that *today's stock price represents investors' expectations regarding future cash flows from holding that stock in terms of dividends and price appreciation*.[334] The BCUC also applies the CAPM model and notes that adjustments to the risk-free rate are necessary as *investors are factoring higher interest rates into their longer-term expectations and required returns*.[335]

Furthermore, similar to the AUC, the BCUC is also guided by the FRS, and hence investors' perspectives play an important role in determining whether financial integrity and capital attraction under the FRS have been met.[336]

UK

The UK energy regulator Ofgem considers investors' perspectives relevant to setting cost of capital parameters and capital structure in terms of their expectations, perceptions of risks, and deemed financial attraction.

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[332] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. P.23.

[333] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. P.29-30.

[334] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. P.65.

[335] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. P.66.

[336] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

Ofgem notes that the allowed return on equity is *an estimation of the return that equity investors expect.*[337] Similarly, the cost of debt allowance is *an estimation of the return debt investors expect from an efficiently run company*.[338]

When determining the allowed ROE using the CAPM, Ofgem considers investors' perspectives where it states that *most [total market returns ("TMR")] evidence suggests that investors are assuming a lower TMR than 6.5%.*[339] Also, Ofgem notes that *investors' expectations should reflect the impact of [Return Adjustment Mechanisms ("RAM")] thresholds*, which are designed to protect investors against the possibility of unreasonably high or low returns during the price control period.[340] Ofgem also notes that beta estimates should *reflect investor perception of systematic risk.*[341]

Additionally, Ofgem notes that investors desire a degree of inflation protection, and thus Ofgem decides to *offer inflation protection to investors through inflation adjustments to the RAV. Returns on capital are also provided in real terms. Together these approaches make inflation a key parameter for the RIIO-ED2 price control*.[342]

Furthermore, Ofgem considers investor attraction when setting allowances for raising capital and dividend yield for modeling an efficient notional company, and examines whether the allowances *provide sufficient returns to attract investors*.[343]

A summary of the jurisdictional review is shown below.

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337 Ofgem. RIIO-ED2 final determinations overview document. November 30th, 2022.

338 Ofgem. RIIO-ED2 final determination finance annex. November 30th, 2022. P.10.

339 Ofgem. RIIO-ED2 final determination finance annex. November 30th, 2022. P.40.

340 Ofgem. RIIO-ED2 final determination finance annex. November 30th, 2022. P.57.

341 Ofgem. RIIO-ED2 final determination finance annex. November 30th, 2022. P.152.

342 Ofgem. RIIO-ED2 final determination finance annex. November 30th, 2022. P.99.

343 Ofgem. RIIO-ED2 final determination finance annex. November 30th, 2022. P.117.

Figure 48. Summary of the jurisdictional review (relevance of investor perspectives)

Jurisdiction	Relevant perspectives	Implication
Alberta	• **Perception of macroeconomic risks**: the increasing credit spread between A-rated utilities and government bonds *demonstrates investors' concerns about the macroeconomic conditions for utilities*, and capital market volatility *could flare up again until investors are once again confident that conditions have stabilized* • **Expectation of market conditions**: the process of setting credit metrics required to maintain an A-range credit rating for utilities is influenced by investor expectations, *applied to an assessment of the relative risk of the utility sector, and perceptions of the regulatory environment* • **Financial integrity and capital attraction**: investors' perspective is an important factor when determining if financial integrity and capital attraction under the FRS have been met	• **Perception of macroeconomic risks:** while the AUC acknowledges that there has been a deterioration in macroeconomic conditions since 2018, Alberta's supportive regulatory environment can protect utilities from adverse macroeconomic changes • **Expectation of market conditions:** the AUC considers the credit metrics reflected in credit rating and market analyst reports to be *generally reflective of future expectations of utility debt and of equity investors with respect to credit metric fundamentals* • **Financial integrity and capital attraction:** the return should be sufficient *to assure [investors'] confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital*
British Columbia	• **Perception of business risks**: debt and equity investors view credit ratings as reflective of credit rating agencies' assessment of the riskiness of their investments, and lowering credit ratings may raise concerns for potential investors regarding the utilities' cost of debt and access to the credit market at reasonable costs • **Expectation of the business:** investors' perspectives have been considered when calculating the allowed ROE • **Financial integrity and capital attraction**: investors' perspective is an important factor when determining if financial integrity and capital attraction under the FRS have been met	• **Perception of business risks:** the BCUC establishes an ROE and capital structure which allow for the utilities to maintain their existing credit agency ratings and avoid eroding each utility's ability to access capital at reasonable costs • **Expectation of the business**: the DCF model used for setting the allowed ROE is based on the premise that *today's stock price represents investors' expectations regarding future cash flows from holding that stock in terms of dividends and price appreciation*; and the adjustment to the risk-free rate of the CAPM is necessary as *investors are factoring higher interest rates into their long-term expectations and required returns* • **Financial integrity and capital attraction:** the return should be sufficient to assure the financial integrity of utilities and attract capital
United Kingdom	• **Perception of business risks**: investors desire a degree of inflation protection; beta estimates should reflect investors' perception of the systematic risk • **Expectation of the business**: the allowed ROE is *an estimation of the return that equity investors expect* • **Investor attraction**: investors' perspective is an important factor when determining whether the investor attraction has been met	• **Perception of business risks**: Ofgem offers inflation protection to investors through inflation adjustments to the RAV and setting returns on capital in real terms • **Expectation of the business**: investors' expectations should reflect RAMs which are designed to protect investors against unreasonably high or low returns during the price control period • **Investor attraction**: Ofgem considers investor attraction when setting allowances for raising capital and dividend and examines whether the allowances provide sufficient returns to attract investors

4.11.3 Potential alternatives

The OEB may consider the following options:

1. **Status quo:** As described in Section 4.11.1, the status quo has appropriately considered debt and equity investor perspectives. The OEB can continue with similar approaches to determining the cost of capital parameters.

2. **Status quo with more frequent reviews of cost of capital methodology:** The OEB may initiate a generic proceeding in practice every five years to review if the allowed cost of capital methodology continues to be responsive to macroeconomic changes and meets the FRS. The OEB may set the scope of the proceeding based on the need at the time.

4.11.4 Recommendations

LEI believes that the OEB's existing cost of capital regime (including the determination of deemed capital structure) appropriately considers investor perspectives, as market data included in the formula and risk assessment when determining the appropriate equity thickness, when considered appropriately, should reasonably reflect investors' perspectives. The OEB can slightly modify the reporting requirements to enable better monitoring of the actual utility cost of capital (discussed in detail in Section 4.14).

LEI recommendation - Issue 11

- 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.

4.12 Capital structure – setting capital structure in accordance with the FRS

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

4.12.1 Status quo

The OEB's policy/guidelines *assume that the base capital structure will remain relatively constant over time* and require undertaking a full reassessment of a utility's capital structure only in the event of significant changes in the company's business and/or financial risk.[344]

As such, the OEB sets a uniform ROE for all regulated entities, and it increases the equity thickness in the capital structure if it assesses that an entity's business and financial risks have increased relative to the previous assessment. On the other hand, the allowed equity thickness can be reduced if OEB assesses that the business and financial risks for a regulated utility has decreased significantly.

As described in Section 4.2, business and financial risks are risks related to uncertainty surrounding a company's operating earnings and ability to finance its investments. The AUC defines business risk as follows: *Business risk represents the perceived uncertainty in future operating earnings before the impact of financial leverage (EBIT) and, hence, determines the capacity for a business to be financed with debt as opposed to equity.*[345] Financial risks are primarily linked to a company's

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[344] OEB. EB-2009-0094. Report of the Board on the cost of capital for Ontario's regulated utilities. December 11th, 2009. Page 50.

[345] AUC. Decision 20622-D01-2016 - 2016 Generic Cost of Capital. October 7th, 2016. Page 115.

ability to continue to finance its capital needs and growth opportunities by attracting investors at reasonable terms.

The key business and financial risks considered by the OEB in recent equity thickness proceedings are discussed earlier in Section 4.2. Meeting the FRS is a key consideration in these proceedings. For instance, if the OEB concludes that the risk profile of a utility has increased, it increases the allowed equity thickness commensurate with increased risk. With respect to the three regulated sectors:

- In 2006, the OEB set the deemed capital structure at 60% debt and 40% equity for all ***electricity distributors and transmitters***. The capital structure is set on a case-by-case basis for other regulated entities.

- ***OPG***'s equity thickness was set at 47% between 2008 and 2014. This was reduced to 45% in 2014 and has remained unchanged since then.

- ***Enbridge Gas***' equity thickness was approved at 36% between 2006 and 2023. The OEB recently approved an increase in Enbridge Gas' equity thickness to 38%, applicable for 2024 rates. ***EPCOR Natural Gas***' equity thickness of 40% has remained unchanged since 2006.

4.12.2 Relevant jurisdictional review

LEI examined the processes of determining the deemed equity ratio in Alberta, Australia, and the UK.

Alberta

The AUC is required to *determine a fair return on the deemed equity component of invested* capital (i.e. the deemed equity ratio) to satisfy the FRS.[346] It adjusts deemed equity ratios to recognize risk differentials among utilities that have a uniform approved ROE.

The AUC uses credit rating targeting in the A-range as one of the major factors to determine the deemed equity ratio. It acknowledges the importance of maintaining an A-range credit rating for utilities, especially when interest rates rise, and considers that using the A-range credit rating target *respects the financial integrity, capital attraction, and comparability aspects of the [FRS]*.[347]

[346] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 44.

[347] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 47.

Consequently, the AUC evaluates three credit metrics commonly used by credit rating agencies:[348]

1) **Earnings before Interest and Taxes ("EBIT") coverage:** calculated as EBIT divided by the sum of the return on debt amount and the interest on the CWIP balance, using the deemed debt ratio and the embedded average debt rate;
2) **Funds from Operations ("FFO") coverage:** calculated as the sum of the return on debt amount, the net income, and the depreciation divided by the sum of the return on debt amount and the interest on the CWIP balance, using the deemed debt ratio and the embedded average debt rate; and
3) **FFO/debt:** calculated as the sum of the net income and the depreciation divided by the sum of the deemed mid-year debt for rate base and CWIP.

The AUC then performs a sensitivity analysis to evaluate the effect of a range of equity ratios on the three credit metrics to arrive at the deemed equity ratios.

Australia

The AER determines the deemed gearing ratio (i.e. the deemed debt ratio) based on a benchmarking approach that examines relevant empirical evidence. The empirical estimation of the benchmark gearing ratio is based on five comparators' gearing ratios calculated using market values of equity and book value of debt since 2006.[349] The set of comparator companies consists of five listed Australian NSPs with data going back to 2006. Although four of the five companies have been delisted in the recent five years, the AER does not exclude them from the comparator set, since their historical data can *still be useful* in its consideration.[350] The five-year average, ten-year average, and average since 2006 across the comparator companies are calculated separately.

The AER aims to satisfy the NEO and NGO principles. The AER notes that the approach for estimating the ratio *will contribute to achieving the NEO and NGO to the greatest degree*.[351] This is because the benchmarking approach *both provides an incentive for service providers to adopt efficient gearing structures and prevents exposing consumers to different gearing levels adopted by individual*

[348] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023

[349] The book value of debt is used as a proxy for the market value of debt. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

[350] AER. Rate of return instrument. Explanatory statement. February 2023. Page 92.

[351] AER. Rate of return instrument. Explanatory statement. February 2023. Page 84.

service providers,[352] and the empirical study is *also consistent with [AER's] estimation of equity beta and credit rating*.[353,354]

British Columbia

The BCUC is obligated to ensure the *approval of rates to meet the FRS*.[355] It considers four factors when determining the deemed capital structure:[356]

1) Compensation to shareholders for the business risks of the benchmark utilities (FEI and FBC);
2) The approach to addressing the financial risk differentials through adjusting the capital structure;
3) Financial flexibility where the benchmark utilities have spare borrowing capacity; and
4) Benefits of maintaining the current credit ratings of benchmark utilities.

The BCUC concluded in 2022 that FEI has been facing increased risks since 2013, and therefore, an increase in FEI's equity component is warranted. The BCUC agreed with FEI on the proposed deemed equity ratio of 45%. FEI proposed the deemed equity ratio of 45% based on authorized equity ratios of its US proxy groups and the target of maintaining an A-level credit rating.[357] FEI's independent expert endorsed FEI's proposed ratio and compared the weighted ROEs, equal to the authorized ROE multiplied by the deemed equity ratios, for FEI and companies in its proxy group. He concluded that the proposed ratio is justified by FEI's risk profile and market data.[358]

The BCUC concluded that the 45% deemed equity ratio *meets the comparable investment and capital attraction requirements* as the figure is premised on FEI's proxy group and supported by its assessment of FEI's business risk.[359] Also, the increase from the previous equity ratio of 38.5%, which has not been changed since 2013, to the current level of 45% *will maintain FEI's financial*

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[352] The AER notes that all else being equal, variations in gearing levels lead to different rates of return and different prices across NSPs. Source: Ibid.

[353] The AER notes that the gearing ratio can affect a company's leverage risk which can impact equity beta and be a factor for credit rating agencies to consider. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

[354] AER. Rate of return instrument. Explanatory statement. February 2023. Page 84.

[355] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. Page 127.

[356] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

[357] FortisBC Utilities. BCUC generic cost of capital. Exhibit B1-8. FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC Utilities) evidence. January 31st, 2022.

[358] BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

[359] Ibid. Page 134.

integrity.[360] The BCUC also concluded that a 45% equity component *forms an optimal capital structure based on the evidence* and provides sufficient financial leverage and flexibility.[361]

Similarly, the BCUC determined FBC's deemed equity ratio to be 41% using the same rationale which considered the FRS, business risk, comparable investments, credit rating, financial leverage, and financial flexibility.

A summary of jurisdictional review on approaches to setting deemed capital structure and the way they reflect the FRS (or similar standards) is shown in Figure 49.

Figure 49. Summary of the jurisdictional review (Issue 12)

Jurisdiction	Approach to determining deemed capital structure	How the FRS is reflected
Alberta	• Use the targeting of credit ratings in A-range by considering EBIT coverage, FFO coverage, and FFO/debt • Perform a sensitivity analysis to evaluate the effect of a range of equity ratios on the credit metrics and select the one ratio that leads to a credit rating in A-range with its own judgment	• The use of the A-range credit rating target is a factor that respects the financial integrity, capital attraction, and comparability aspects of the FRS
Australia	• Use a benchmarking approach based on comparator companies' gearing ratios calculated using market values of equity and book value of debt since 2006 • Compare the resulting average gearing ratios of the comparator set with the previous allowed gearing ratio • Conclude that the difference is not significant and hence continue using the previous ratio	• The benchmarking approach contributes to achieving the NEO and NGO to the greatest degree • The approach provides an incentive for service providers to adopt efficient gearing structures and prevent exposing consumers to different gearing levels • The empirical study is consistent with AER's estimation of equity beta and credit rating
BC	• Consider compensation to shareholders for the business risk • Compare the deemed equity ratio and the weighted ROE with a proxy group • Target an A-level credit rating • Consider financial leverage and flexibility	• The determined deemed equity ratio meets the comparable investment and capital attraction requirements as it is premised on the benchmark utility's proxy group and supported by the assessment of the business risk • An increased deemed equity ratio compared with the previous ratio ensures financial integrity

4.12.3 Potential alternatives

The OEB may consider the following options to set the deemed capital structure:

1. **Status quo:** set a uniform ROE and adjust the capital thickness if, upon application, the OEB assesses there is a meaningful change in business/financial risks.
2. **Set capital structure for each sector using rating agency benchmarks** for a desired rating given the established ROEs. This can be done using a forward-looking cash flow scenario analysis and assessing which capital structure will likely result in credit metric ratios needed for a particular rating.

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360 Ibid.

361 Ibid.

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]

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.

LEI recommendation - Issue 12

- The OEB's current approach of revising the capital structure upon application if warranted due to increase in business/financial risks is a reasonable practice, as OEB has noted that risks rarely change meaningfully in a short period of time.
- LEI believes that the existing approach meets the FRS.
- Applicants should be required to include forward cash flow modeling and scenario analysis showing impact on credit metrics to support their case.

4.13 Capital structure – appropriate capital structure for single vs. multiple-asset transmitters

Issue 13: Should the OEB take a ***different approach for setting the capital structure*** for electricity transmitters depending on whether they are a ***single versus multiple asset transmitter***?

Ontario has eight licensed electricity transmitters.[370] As of 2022, Hydro One accounts for ~91% of the total approved rate base for electricity transmitters. However, the OEB allows the same equity thickness for all electricity transmitters. Issue 13 relates to whether the smaller size of the electricity transmitters (other than Hydro One) increases their risk profile relative to Hydro One, and whether that warrants a higher allowed equity thickness in the capital structure.

4.13.1 Status quo

The OEB stated in EB-2009-0084 that the capital structure for transmitters will be determined on a case by case basis.[371] However, the OEB has allowed a 40% equity thickness to all electricity transmitters (same as electricity distributors) since 2006.

4.13.2 Relevant jurisdictional review

Jurisdictions studied by LEI consider the implication of size differently when determining the deemed capital structure. The size of a utility directly impacts AUC's determination of equity thickness in Alberta only for one gas distribution entity but is not considered by the AER in Australia. In the UK, a single notional gearing is applied to all electricity transmitters, regardless of their size.

Alberta

The AUC sets a generic deemed equity ratio of 37% for all electric and gas transmitters with one exception of Apex Utilities Inc. ("Apex") which is a gas distribution company with a deemed

[370] OEB. List of licensed companies. Accessed on May 21st, 2024.

[371] OEB. EB-2009-0084. Report of the Board on the Cost of Capital for Ontario's Regulated Utilities. December 11th, 2009.

equity ratio of 39%.[372] For all electric transmitters of different sizes (rate bases) as shown in Figure 51, the AUC sets a uniform deemed equity ratio.

Figure 51. Electric and gas transmission companies regulated by the AUC

Electric transmitter	2023 Rate base ($millions)
AltaLink L.P.	7,361
ATCO Electric Transmission	5,796
ENMAX Power Corporation	788
EPCOR Distribution and Transmission Inc.	794
KainaiLink L.O.	32
PiikaniLink L.P.	47
TransAlta Corporation	54

Source: AUC. *Rule 005 report*. 2024.

Australia

The AER sets a single benchmark for all NSPs (which includes electric transmitters and distributors), regardless of the size, which, from the AER's perspective, is the best way to achieve the NEO and/or NGO. The single benchmark *prevents exposing consumers to different gearing levels adopted by individual service providers*.[373] The benchmarking approach includes latest market information and considers short-term and long-term outcomes *to the extent they reflect changing market conditions*.[374]

United Kingdom

Ofgem considers notional gearing *in light of the risks network companies face, rating agency views on gearing levels for investment grade regulated networks, balancing an appropriate cost of capital and the impact medium term market conditions have on debt servicing*.[375] Ofgem sets a notional gearing of 55% for all electric transmission companies and a notional gearing of 60% for National Grid Gas Transmission, regardless their varying sizes.

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[372] The upward adjustment is due to additional risks arising from *Apex's small size, geographically dispersed service territory in rural Alberta, and gas supply risk*. The higher equity ratio provides Apex with greater revenues to compensate for the inability to generate cost savings and efficiencies that stem from economies of scale. Also, the additional equity provides Apex with *a better opportunity to achieve higher interest coverage ratios while reducing the financial risk*, which helps Apex maintain its credit rating and meet the FRS. Source: AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 62.

[373] AER. Rate of return instrument. Explanatory statement. February 2023. Page 84.

[374] AER. Rate of return instrument. Explanatory statement. February 2023. Page 95.

[375] Page 175.

Figure 52. Notional gearing ratio of transmission companies regulated by Ofgem

Utility	Notional gearing	2023 Regulatory asset value ($billions)
National Grid Electricity Transmission	55%	17.1
Scottish Power Transmission	55%	3.1
Scottish Hydro Electric Transmission	55%	4.8
National Grid Gas Transmission	60%	6.6 (2022)*

Source: Financial reports of the listed utilities.

A summary table of the jurisdictional review on the implication of the size of a utility is shown in Figure 53.

Figure 53. Summary of the jurisdictional review (equity ratio for transmitters of varying sizes)

Jurisdiction	Implication of size
Alberta	Electric transmitters of varying sizes are allowed the same equity ratio
Australia	A single benchmark equity ratio applied to all NSPs, regardless of their sizes
UK	A single notional gearing ratio applied to all electric transmitters, regardless of their sizes

4.13.3 Potential alternatives

The OEB may consider the following options:

1. **Status quo:** continue to allow the same equity thickness for all electricity transmitters; or
2. **Grouping electricity transmitters based on their risk profile**, considering size as a proxy for risk i.e., determining the capital structure for Hydro One separately and a slightly higher uniform capital structure for the other transmitters.

4.13.4 Recommendations

The reasoning provided by the OEB in 2006 to move away from the size-based capital structure determination (described in Section 4.12.4) for electricity distributors also applies to electricity transmitters. The risk profile of electricity transmitters is similar to, if not lower than, that of electricity distributors. As such, it is reasonable to consider the same approach to setting capital structures as electricity distributors.

Moreover, size is less of an issue for Ontario's electricity transmitters as transmitters have essentially one customer: IESO.[376,377] Variations in OM&A expenses are likely minor, and efficiencies can be achieved through contracting out. Transmitters (big and small) cannot diversify customer risk or economic risk but are likely insulated from volume risk based on their tariff structure. Many licensed transmitters are also part of larger entities (for example, B2M Limited Partnership and Hydro One Sault Ste. Marie LP are subsidiaries of Hydro One; Canadian Niagara Power Inc. is a subsidiary of Fortis Inc.). Further, similar to electricity distributors, allowing higher equity thickness for smaller transmitters may discourage the consolidation of smaller entities.

LEI, therefore, recommends that the OEB retain its approach of allowing a uniform deemed capital structure to all electricity transmitters.

LEI recommendation - Issue 13

LEI recommends that the current approach of allowing the same equity thickness to all electricity transmitters (and distributors) be maintained.

4.14 Mechanics of implementation – monitoring mechanism to test the reasonableness of the cost of capital methodology

Issue 14: ***What on-going monitoring indicators to test the reasonableness of the results generated by its cost of capital methodology should the OEB consider, including the monitoring of market conditions?***

This issue is strictly concerned with the OEB's ***ongoing monitoring*** of the cost of capital parameters/values; the issue of more comprehensive ***periodic reviews*** of the cost of capital policy as a whole is covered separately – specifically under Issue 17 in the Final Issues List (see Section 4.17).

4.14.1 Status quo

As described by OEB Staff, "*macroeconomic conditions and their impact on cost of capital are monitored throughout the year, and any major changes could trigger an updated calculation*."[378] This ongoing monitoring process is conducted through quarterly reports that are prepared for internal review purposes only and thus are not released publicly. LEI has been retained by the OEB to prepare these quarterly reports since 2019. These quarterly reports comprise of two key analytical components:

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376 IESO. Introduction to the IESO Settlement Process. May 2023. Page 10.

377 Hydro One considers IESO the related party for all its regulated transmission revenues. Source: EB-2021-0110.

378 OEB. *OEB Staff Report: Review of the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084).* January 14, 2016. P. 4.

- first, the quarterly reports use updated data to recalculate the cost of capital parameters, which are then compared to the values published as part of the OEB's annual cost of capital updates; and
- simultaneously, the quarterly reports incorporate a review of the current macroeconomic outlook on a global, North American, and provincial scale, including key macroeconomic developments that have unfolded in the previous quarter.

Together, the quarterly reports serve as a tool for OEB staff to monitor the reasonableness of the cost of capital parameters on an ongoing basis and ensure that the parameters continue to be aligned with prevailing macroeconomic trends.

4.14.2 Relevant jurisdictional review

Among the jurisdictions reviewed by LEI, ongoing public reporting/monitoring of cost of capital parameters (in between official updates) by the regulator does not appear to be common practice.

Alberta

In Alberta, cost of capital parameters must be reviewed by the AUC every five years; a mid-term reopener mechanism is also in place, which enables the AUC to initiate an earlier review either at its own discretion or upon application by an interested party.[379] However, there do not appear to be any other requirements for ongoing public reporting/monitoring of cost of capital parameters by the AUC.

Australia

In Australia, where the rate of return for regulated electricity and gas networks is set for a four-year period, the AER publishes annual updates to "*provide stakeholders with regular information on rate of return data [between reviews], particularly time series market data, showing changes since the publication of the [Rate of Return] Instrument*."[380] As described by the AER, the intent of the annual updates is to "*provide a foundation for substantive, constructive discussion with all stakeholders during the [next] review*."[381] For example, as part of the December 2023 update, the AER updated key rate of return parameters and calculated an indicative rate of return using updated market data up to August 2023 – see Figure 54.

British Columbia

In British Columbia, there is no prescribed statutory timeline within which the BCUC must review a utility's cost of capital – a review can be initiated either by the BCUC at its own

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[379] AUC. Cost-of-capital parameters in 2024 and beyond. October 16, 2023.

[380] AER. *Rate of Return Annual Update 2023.* December 2023.

[381] Ibid.

discretion, or upon application by a utility.[382] Similar to the case of Alberta, LEI has found no evidence of other requirements for ongoing public reporting/monitoring of cost of capital parameters by the BCUC.

Figure 54. Snapshot from AER's Annual Rate of Return Update

Parameter	2022 Instrument (Data as published in the 2022 Instrument Explanatory Statement)	2023 update
Indicative overall rate of return (nominal vanilla)	6.84%	6.98%
Gearing ratio	60%	60%
Indicative return on debt (annual estimate)	6.52% (using on-the day return on debt estimated over Dec 2022)	6.37% (Using on-the day return on debt estimated over Aug 2023)
Market risk premium	6.2%	6.2%
Equity beta	0.60	0.60
Indicative risk-free rate	3.60% (10-year term)	4.19% (10-year term)
Indicative return on equity	7.32% (using a risk-free rate of return estimated over Dec 2022)	7.91% (using a risk-free rate of return estimated over Aug 2023)
Value of imputation credits (gamma)	0.57	0.57
Benchmark credit rating	BBB+	BBB+

Source: AER. *Rate of Return Annual Update 2023.* December 2023.

California

In California, the CPUC has adopted a multi-year Cost of Capital Mechanism ("CCM") for the large investor-owned utilities that it regulates,[383] which is applied for three-year cycles. The CCM automatically adjusts a utility's cost of capital if a certain threshold is met in each year of the three-year cycle; the utility is not required to file a cost of capital application.[384] LEI has found no

[382] BCUC. *Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23.* September 5, 2023.

[383] The large investor-owned utilities are Southern California Edison Company ("SCE"), San Diego Gas & Electric Company ("SDG&E"), Southern California Gas Company ("SoCalGas"), and Pacific Gas and Electric Company ("PG&E").

[384] In any year where the difference between the current 12-month October through September average Moody's utility bond rates and the benchmark exceeds 100 bp, an automatic adjustment to the ROE shall be made by an October 15th advice letter, effective on January 1st of the next year, as follows: 1) ROE is adjusted by 50% of the difference between the Aa utility bond average for AA credit-rated utilities or higher and Baa utility bond average for BBB credit-rated utilities or lower and the benchmark; 2) long-term debt and preferred stock costs are updated to reflect actual August month-end embedded costs in that year and forecasted interest rates for variable long-term debt and new long-term debt and preferred stock scheduled to be issued; and 3) the 12-month October through September average that triggered the CCM becomes the new benchmark. For example, assuming the new actual October through September average Moody's Aa utility bonds is 5.0% while the benchmark is 6.5%, the difference is 150 bp, exceeding 100 bp. Thus, ROE is downward adjusted by 75 bp; long-term cost of debt is updated from 6.40% to 6.30% based on the actual cost of debt; and the new benchmark is 5.0%. Source: CPUC. *Decision 08-05-035. Decision establishing a multi-year cost of capital mechanism for the major energy utilities.* May 29, 2008.

evidence of other requirements for ongoing public reporting/monitoring of cost of capital parameters by the CPUC.

4.14.3 Potential alternatives

LEI explored three potential alternatives for monitoring the reasonableness of the cost of capital parameters/values on an ongoing basis:

1. **Status quo (private reporting):** the OEB could continue to have its quarterly reports prepared for internal review purposes only, which would continue to allow OEB staff to calculate the cost of capital parameters with updated data and ensure that they are consistent with prevailing macroeconomic conditions. These quarterly reports should generally include the following analysis:

    - variance analysis – calculating the ROE, DLTDR, and DSTDR using updated data and comparing the resulting values to the parameters published as part of the most recent annual cost of capital update;

    - discussion of trends in economic growth, inflation, interest rates, and investor confidence in Canada and the US;

    - exploration of key factors driving these trends;

2. **Public reporting:** the OEB could publish its quarterly reports publicly, which would enable stakeholders to (i) understand the impact of updated data on the cost of capital parameters, and (ii) keep up to date with major macroeconomic developments. Similar to the approach taken by the AER in Australia, these regular updates could be provided for informational purposes only; or

3. **No reporting:** given the experience in the other jurisdictions reviewed by LEI, ongoing monitoring of the cost of capital parameters in between more comprehensive periodic reviews does not appear to be common practice. Therefore, one alternative would be to remove the quarterly reporting requirement altogether, which would limit the review of the cost of capital parameters to occurring only during the periodic reviews (as discussed later in Section 4.17), in line with the approach taken in Alberta, British Columbia, and California, for example.

4.14.4 Recommendations

Aside from Australia, LEI is not aware of examples of ongoing public monitoring/reporting by regulators regarding cost of capital in between major reviews. Therefore, LEI believes the OEB's current approach of monitoring the cost of capital parameters on a quarterly basis through reports prepared for internal purposes only continues to be appropriate, and does not appear to be inconsistent with approaches taken in the jurisdictions reviewed by LEI.

LEI notes that it would have come to this conclusion and recommendation even if it was not currently being retained by the OEB to prepare these quarterly reports. This is because LEI's recommendation to retain the status quo is consistent with the principles outlined in Section 3.1. Ongoing monitoring of the cost of capital parameters enables the OEB to ensure the FRS continues to be met. It is also simple to administer – even though monitoring takes place fairly frequently (each quarter), the quarterly reports need only be prepared for internal review purposes. Finally, continuing with the status quo provides confidence to all stakeholders regarding the durability of the monitoring approach.

LEI recommendations – Issue 14

Consistent with the OEB's existing policy, OEB staff should continue to monitor the cost of capital parameters and test their reasonableness in the context of prevailing macroeconomic conditions on a quarterly basis, through reports prepared for internal review purposes only.

4.15 Mechanics of implementation – review mechanism to ensure adherence to FRS

Issue 15: ***How should the OEB regularly confirm that the FRS continues to be met and that rate-regulated entities are financially viable and have the opportunity to earn a fair, but not excessive, return?***

As described previously in Section 3.1, the Fair Return Standard is a legal framework for setting the return on capital for regulated electricity and gas utilities; the FRS states that three requirements must be satisfied in order to determine a fair and reasonable return on capital:

- **comparable investment standard:** a fair or reasonable return on capital should be comparable to the return available from the application of invested capital to other enterprises of like risk;
- **financial integrity standard:** should enable the financial integrity of the regulated enterprise to be maintained; and
- **capital attraction standard:** should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions.

4.15.1 Status quo

As described by the OEB, "*each time a formulaic approach is used to calculate an allowed ROE, it must generate a number that meets the Fair Return Standard, as determined by the OEB using its experience and informed judgment*."[385] For example, as part of the 2024 annual cost of capital update letter, the OEB determined that the formula-generated "*cost of capital parameter values … and the relationships between them, [are] reasonable and representative of market conditions at this time. For this reason, the OEB concludes that the numerical results from the formulaic methodologies meet the Fair Return Standard*."[386] However, if the formulaic methodologies were to produce cost of capital parameter

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

[386] Ibid.

values that "*in the view of the Board, raise doubt that the Fair Return Standard is met, the Board may then use its discretion to begin a consultative process*."[387]

4.15.2 Relevant jurisdictional review

In Alberta, the AUC ensures the cost of capital parameters (and specifically the ROE) continue to satisfy the FRS by conducting a periodic review of its cost of capital policy every five years. As described by the AUC:

> *The Commission has determined that a periodic review every five years strikes an optimal balance. This duration ensures the ongoing alignment of the formula-derived ROE with the established fair return standard, while maintaining the objectives of regulatory efficiency and certainty. The Commission emphasizes that this review process does not necessarily imply a fully litigated GCOC process resulting in a resetting of the formula's parameters, including base ROE. Rather, the Commission will initially seek input from parties on the preliminary assessment of the formula's continued capacity to generate a fair ROE. The Commission's decision on whether to undertake a comprehensive review of either the ROE in general, or the ROE formulaic approach in particular, will be informed by the feedback received on the preliminary matters. The Commission will retain full discretion in determining the process to be followed.*[388]

4.15.3 Potential alternatives

There are several ways in which a regulator can confirm that the cost of capital parameters continue to meet the FRS.

In terms of frequency, this could either be reviewed on:

1. **a quarterly basis**, as part of the OEB's existing internal quarterly reporting/monitoring process (as described previously in Section 4.14);
2. **an annual basis (status quo)**, as is done by the OEB currently through its annual cost of capital update letters; or
3. **a less frequent basis**, as is the case in Alberta, such as every five years or whenever a cost of capital review is initiated.

In terms of mechanisms, determining whether the cost of capital parameters continue to meet the FRS could be done through:

1. **monitoring the credit ratings of the regulated utilities**, including observing whether any credit rating changes have occurred, and if they have, whether the changes were attributed to the regulatory framework;

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

388 AUC. Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023). October 9, 2023.

2. **monitoring utility analyst reports**;

3. **comparing to the actual returns of a group of peer utilities**, to assess whether there are deviations, and the reasons for such deviations, if any;

4. **assessing how risks have changed since the cost of capital parameters were last updated**, and reviewing whether these risk changes are appropriately accounted for in the updated cost of capital parameters; or

5. **leveraging utility financial reporting processes to track the pace of capital injections for each utility** and check for any material changes over time.

4.15.4 Recommendations

The OEB currently confirms whether the FRS continues to be met through its annual cost of capital update letters. LEI would also recommend monitoring any changes in the credit ratings of the regulated utilities, as well as the pace of capital injections. Utilities are currently required to report their audited financial information (such as earned ROE) on an annual basis.[389] To ease the review process, the OEB should direct the utilities to also submit the following additional information as part of the annual reporting requirements:

- credit ratings, if available, for short-term debt and secured/unsecured long-term debt from all major credit rating agencies (such as S&P Global, DBRS Morningstar, Moody's and Fitch); and

- details of new short-term and long-term debt and equity issued/borrowed during the year, as well as details regarding any failed attempts to secure debt and equity, or instances where the utility faced materially higher than expected costs to secure debt and equity. For short-term and long-term debt, utilities could report on details such as the amount issued/borrowed, maturity period, rate structure (such as fixed or variable rates), and the interest rates received:

    - for short-term debt, utilities could report the details of Commercial Paper issued and/or the revolving working capital facilities; and

    - for long-term debt, utilities could report the details of medium-term/long-term corporate bonds and the loan details.

LEI's recommendation to retain but augment the status quo, by continuing to confirm whether the FRS is being met through the OEB's annual cost of capital update letters, is consistent with the principles outlined in Section 3.1. By definition, this approach ensures the cost of capital policy, parameters, and values continue to meet the FRS on an ongoing basis. This approach is also simple to administer, as it requires only an annual review and update.

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[389] OEB. *Electricity Reporting and Record Keeping Requirements.* Effective March 8, 2023.

The OEB should direct utilities to submit some or all of the additional information listed above as part of the annual reporting requirements. This would further promote transparency, as well as provide important information that that the OEB could monitor on an ongoing basis. Furthermore, LEI does not expect these additional reporting requirements to introduce a significant regulatory burden for utilities, as their finance departments should have the aforementioned details readily available.

LEI recommendations – Issue 15

The OEB should continue to annually confirm that the FRS is being met, as it currently does through its cost of capital update letters. In addition, the OEB should direct utilities, as part of the annual reporting requirements, to provide credit ratings and details regarding new short-term and long-term debt and equity issued/borrowed during the year. The OEB can use this information to monitor the credit ratings and pace of capital injections for the regulated utilities on an ongoing basis, as a further test of whether the FRS continues to be met.

4.16 Mechanics of implementation – the timing of the OEB's annual cost of capital parameters updates

Issue 16: ***What should be the timing of the OEB's annual cost of capital parameters updates, including the timing, as required, of the underlying calculations?***

4.16.1 Status quo

The OEB updates the cost of capital parameters every year and publishes a letter with the updated parameters in October or November for rates taking effect in January of the following year. The underlying calculations typically rely on data as of the end of September.[390]

4.16.2 Relevant jurisdictional review

Alberta

In Alberta, the AUC updates the allowed ROE annually and the deemed equity ratio every five years. The allowed ROE is calculated by the AUC each November using October data; the calculated ROE then comes into effect in January of the following year.[391]

[390] OEB. *Cost of Capital Parameter Updates.* Last revised October 31, 2023.

[391] AUC. *Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023).* October 9, 2023.

British Columbia

In British Columbia, the BCUC is not required to conduct periodic reviews of cost of capital parameters. However, during the most recent GCOC proceeding, rates were effective in January 2023, with the cost of capital analysis based on October 2022 data.[392]

Australia

In Australia, the AER updates the cost of capital parameters in its Rate of Return Instrument every four years. The Instrument for the following regulatory period is typically published in December of the fourth year of the current four-year cycle. Then utilities are required to "*submit regulatory proposals in January and also manage administrative practicalities of finalizing regulatory determinations in April and annual pricing proposals*."[393] However, the AER delayed its 2022 Rate of Return Instrument decision (for the 2023-2026 period) until February 2023 due to information availability issues; nevertheless, the AER intends to publish the 2026 Rate of Return Instrument (for the 2027-2030 period) on schedule in December 2026.[394]

4.16.3 Potential alternatives

Among the jurisdictions reviewed by LEI, rates typically come into effect in January.[395] However, the timing of the annual cost of capital parameter updates vary – October/November under the OEB's current approach (using data as of the end of September), November in Alberta (using October data), and December in Australia.

4.16.4 Recommendations

LEI does not see any reason to change the timing of the OEB's annual cost of capital parameter updates and therefore recommends continuation of the current approach. LEI's recommendation to retain the status quo is consistent with the principles outlined in Section 3.1. Stakeholders are familiar with the OEB's existing cost of capital update schedule, and so continuing this approach would promote predictability and stability objectives.

LEI recommendations – Issue 16
Consistent with the OEB's existing policy, the OEB should continue to publish its annual cost of capital parameter updates in October or November, using 12-month trailing data as of the end of September (i.e., from October of the previous year to September of the current year), for rates going into effect in the following January.

392 BCUC. *Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23.* September 5, 2023.

393 AER. *Rate of return instrument. Explanatory statement.* February 2023. Page 39.

394 Ibid.

395 LEI also found that rates come into effect in January in Manitoba and Nova Scotia.

4.17 Mechanics of implementation – defined interval to review the cost of capital policy

> Issue 17: ***What should be the defined interval (for example, every three to five years) to review the cost of capital policy (including, but not limited to, a review of the ROE formula and the capital structure)? Should the OEB adopt trigger mechanism(s) for a review and if so, what would be the mechanisms?***

4.17.1 Status quo

The OEB's 2009 decision established the process of periodically reviewing the cost of capital policy every five years. This five-year interval was found to "*provide an appropriate balance between the need to ensure that the formula-generated return on equity continues to meet the Fair Return Standard and the objective of maintaining regulatory efficiency and transparency*."[396] Following the 2009 decision, the OEB subsequently commenced a review on schedule in 2014. This review culminated in a 2016 report by OEB Staff, which concluded that the cost of capital methodology continued to "*work as intended*", such that "*movement in the parameters [had] followed macroeconomic trends and activity, and [had] not resulted in excessive or anomalous volatility*."[397] Since the 2016 report no other comprehensive reviews of the formulaic cost of capital policy have been conducted by the OEB, until the current GCOC proceeding.

In terms of trigger mechanisms, LEI understands that there are avenues that a utility can pursue if it believes the formula-generated cost of capital parameters are not reasonable for its specific circumstances:[398]

- as described by the OEB, "*an applicant or intervenors can … file evidence in individual rate hearings in support of different cost of capital parameters due to their specific circumstances, but must provide a strong rationale and supporting evidence for departing from the OEB's policy;*"[399] or

- utilities under Price Cap IR or Annual IR Index rate-setting plans have an off-ramp mechanism in place, which triggers a regulatory review if earnings fall outside a deadband of +/- 300 bp from the approved ROE.[400] LEI notes that this is a relatively broad

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[396] OEB. *EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities.* December 11, 2009.

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

[398] In addition to the two avenues included in the bullet point list, the Z-factor adjustment mechanism in place for utilities under Price Cap IR rate-setting plans is also somewhat relevant. The mechanism enables utilities to "*request to recover costs associated with unforeseen events that are outside the control of a distributor's ability to manage. The cost to a distributor must be material and its causation clear*." However, LEI notes that use of the Z-factor adjustment mechanism to deal with cost of capital parameter deviations would be somewhat unusual. (Source: OEB. *Filing Requirements For Electricity Distribution Rate Applications – 2021 Edition for 2022 Rate Applications (Chapter 3: Incentive Rate-Setting Applications).* June 24, 2021)

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

[400] OEB. *Filing Requirements For Electricity Distribution Rate Applications – 2021 Edition for 2022 Rate Applications (Chapter 3: Incentive Rate-Setting Applications).* June 24, 2021.

trigger mechanism, in that the regulatory review that would ultimately be triggered by the off-ramp may or may not include a review of the cost of capital parameters.

4.17.2 Relevant jurisdictional review

Based on the jurisdictions reviewed, LEI finds that the periodic review interval typically ranges between three to five years, although some jurisdictions have not specified a review schedule for their cost of capital policy at all:

- **Alberta:** the AUC reviews its cost of capital policy every five years, subject to mid-term reopeners that trigger a review either at the AUC's own discretion or upon application by utilities or other interested parties;
- **British Columbia:** the BCUC is not required to conduct periodic reviews of its cost of capital policy, although a review can either be initiated by the BCUC at its own discretion, or upon application by a utility;
- **Australia:** the AER reviews its cost of capital policy every four years;
- **California:** the CPUC reviews its cost of capital policy every three years;
- **New York:** the NYPSC does not have a specific review schedule in place; and
- **United Kingdom:** Ofgem reviews its cost of capital policy every five years.

In addition, some of these jurisdictions have put in place trigger mechanisms that would enable review of the cost of capital policy ahead of schedule. These trigger mechanisms are usually fairly broad, flexible, and not overly prescriptive, enabling the regulator to exercise its own judgment and discretion, as described further below.

Alberta

The AUC's trigger mechanism works as follows:

> *In addition to providing for mandatory five-year reviews (without predetermining in advance the length, scope or complexity of the review process), the Commission also sees merit in allowing for mid-term reopeners either at its own initiative or upon application by interested parties if there are compelling grounds to believe that the ROE resulting from the formulaic approach may no longer be just and reasonable. The Commission envisions mid-term reopeners initiated by parties would be subject to a two-stage review process. In order to move from Stage 1 to Stage 2 of the review process, applicants would bear the burden of establishing on a balance of probabilities that there exist one or more sufficiently compelling reasons for the Commission to question whether its formulaic approach to setting utility ROEs remains, and/or produces results that continue to be, just and reasonable. In the Commission's view, reliance on such a test is likely to quickly dispense with frivolous applications, while still allowing for a broad range of concerns that would justify a deeper examination of the continued reasonableness of the formulaic approach.*

> *The Commission is not persuaded, however, that the potential benefits of establishing thresholds that would automatically trigger offramps for, or reasonableness reviews of, the formulaic approach outweigh the disadvantages of adopting such measures. As noted by AltaLink/EPCOR and Dr. Cleary, respectively: the "Commission should not attempt to predetermine and fix specific thresholds for reopeners or offramps" and "given the difficulty capturing all scenarios where a review may be warranted, the need for a reopener may ultimately be best left to a matter of judgment." In addition, the Commission notes that it has been almost 15 years since it last relied on a formulaic approach to set utility ROEs. The formulaic approach approved in this decision is also different from the last formula relied on by the Commission. As a result, the Commission considers it to be in the public interest – at least until it acquires greater familiarity with how the formula operates under a variety of different circumstances – that the Commission maintain the maximum degree of discretion in determining how and when the formulaic approach should be reviewed when a question arises as to its ability to meet the fair return standard both over time and in light of ever-changing market conditions. Closely related, the Commission is concerned that any mechanical reliance upon predetermined ROE deadbands, ceilings and floors may inadvertently result in both false-positives (i.e., conducting unnecessary reviews) and false-negatives (i.e., failing to undertake necessary reviews).*[401]

However, it is worth noting that in Alberta, electric and gas distribution utilities under performance-based regulation plans are subject to an ROE-based reopener provision that serves as a "*safeguard against unexpected results that could signal that there is a problem with the design or operation of the plan that makes its continued operation untenable*."[402] The reopener provision is triggered when the earned ROE is 500 bp above or below the approved ROE in a single year or 300 bp above or below the approved ROE in two consecutive years.

British Columbia

In the BCUC's recent 2023 GCOC decision, it noted the following:

> *While the BCUC in the 2013 GCOC proceeding indicated that it would review FEI's cost of capital in three years, we do not see the need to be prescriptive in this instance about the timing of the next review. We note that in any event, both FEI and FBC are currently under a multi-year rate plan which includes an off-ramp which is designed as a safeguard to protect the utility and ratepayers against potential unintended consequences (such as windfall surplus or losses) and is triggered if earnings in any one year vary from the approved ROE by +/- 150 bps. That plan expires at the end of 2024 and if there are material changes to markets or economic conditions after that affecting the utilities' ROE, we anticipate that either the BCUC or the utility will initiate a review of any changes at that time.*
>
> *That said, we view that periodic reviews of utilities' cost of capital are desirable in ensuring that utilities continue to have the opportunity to earn a fair return based on their ROE and cost of capital despite changes in circumstances. At the same time, we recognize that such reviews entail*

[401] AUC. Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023). October 9, 2023.

[402] AUC. 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities (Decision 27388-D01-2023). October 4, 2023.

> *significant investments of time and effort on the part of participants and should not be undertaken except where warranted.*
>
> *As for determining specific triggers that would prompt a cost of capital review, we see no merit to doing so in the absence of any evidence or submissions from parties as to what may be appropriate objective triggers. We agree with FortisBC that maintaining overall flexibility over the timing of the next cost of capital review is desirable as a more appropriate response to dynamic market and business factors that are not always foreseeable. For the same reason, we do not consider it particularly helpful to limit the triggers for review to specific occurrences which are only at best speculative.*[403]

United Kingdom

Ofgem reviews cost of capital parameters under the RIIO price control framework every five years. While Ofgem has not implemented a trigger mechanism, it has adopted Return Adjustment Mechanisms ("RAMs"), which provide protection to consumers and investors "*in the event that network company returns are significantly higher or lower than anticipated at the time of setting the price control*."[404] Under the RAMs, the primary threshold is set at the baseline allowed ROE +/- 300 bp, and the primary adjustment rate is 50% applied to the portion of the actual ROE that is outside of the primary threshold; the secondary threshold is set at the baseline allowed ROE +/- 400 bp, and the secondary adjustment rate is 90% applied to the portion of the actual ROE that is outside of the secondary threshold.[405]

Figure 55. Summary of the jurisdictional review

Jurisdiction	Scheduled review?	Broad trigger mechanism for off-cycle review?	Ad hoc application process?
Alberta	Yes (5 years)	No	Yes
British Columbia	No	Yes (+/- 150 bp from approved ROE)	Yes
United Kingdom	Yes (5 years)	No	Yes

4.17.3 Potential alternatives

In terms of timing, the interval between comprehensive reviews of the cost of capital policy could be set as follows, as observed in other jurisdictions:

403 BCUC. Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23. September 5, 2023.

404 Ofgem. RIIO-ED2 final determinations finance annex. November 30, 2022. P. 92.

405 For example, if the baseline allowed ROE is 5.2%, the primary RAMs threshold will be triggered at 2.2% and 8.2% of ROE, while the secondary RAMs threshold will be triggered at 1.2% and 9.2% of ROE.

1. **status quo (periodic reviews every five years):** the OEB's 2009 decision committed to periodically reviewing the cost of capital policy every five years. However, in practice, this has not been the case – only one comprehensive review has been completed since 2009 (i.e., the review that was initiated in 2014 and resulted in an OEB Staff report published in 2016). The AUC in Alberta and Ofgem in the UK have also set a five-year review schedule;

2. **more frequent periodic reviews (e.g., every three years):** the CPUC in California has set a three-year review schedule, while the AER in Australia has set a four-year review schedule; or

3. **no set schedule for periodic reviews:** neither the BCUC in British Columbia nor the NYPSC in New York have specified a set review schedule. Reviews are only conducted when initiated by the regulator or upon application by an interested party.

As for trigger mechanisms, the OEB currently has several mechanisms in place that could involve a regulatory review of the cost of capital parameters, including enabling utilities to apply for different parameters during their individual rate hearings, as well as the off-ramp mechanism. These are generally consistent with the types of trigger mechanisms that LEI has observed in other jurisdictions, which can be categorized as follows:

1. **ad-hoc reviews triggered by the regulator or upon application by an interested party:** as is the case with the AUC's mid-term reopener mechanism, for example; or

2. **broad reviews triggered based on deviations beyond a pre-determined threshold:** as is the case with the BCUC's off-ramp mechanism, for example, which triggers a regulatory review when utility earnings vary from the approved ROE by +/- 150 bp.[406]

4.17.4 Recommendations

Determining the frequency with which the cost of capital policy is reviewed requires balancing multiple competing objectives. First, consistent with the guiding principles discussed previously in Section 3.1, the OEB strives to minimize the time and cost of administering the cost of capital framework, especially because the OEB is responsible for overseeing more than 60 regulated entities. A longer interval between comprehensive reviews would reduce such costs. However, the cost of capital policy should be reviewed with enough frequency to ensure alignment with prevailing macroeconomic conditions, so that investors, utilities, and consumers have reasonable confidence in the OEB's decisions and outcomes.

LEI recommends continuing with a five-year review interval for several reasons. First, the OEB's 2009 decision determined that a five-year interval would provide an appropriate balance between the aforementioned competing objectives. Second, the five-year interval is aligned with the

[406] LEI also considered parameter triggers, such as a more than 300 basis point change in the risk-free rate over a 2-year period. However, the formula already adjusts with interest rates, and utilities can seek review if they are in distress. LEI believes a parameter trigger may create false positives and increase the regulatory burden.

review schedules observed in other jurisdictions, and thus is consistent with international practice. Third, the five-year interval also falls within the range of average business cycle lengths in Canada.[407] However, LEI notes that if the OEB commits to a five-year review interval as part of this GCOC proceeding, it is important that this schedule is adhered to in practice. At the very least, if a periodic review is skipped, the OEB should announce this and provide reasons for this decision – this will ensure the objectives of predictability and stability are upheld.

In terms of trigger mechanisms, LEI recommends continuing the mechanisms that are already in place – including triggering a review upon application by a utility during an individual rate hearing, as well as the off-ramp mechanism. These mechanisms ensure that both manual and mechanistic triggers are in place to initiate a review of the OEB's cost of capital policy. LEI finds that taken together, these mechanisms enable flexibility in the review process while also ensuring that adequate safeguards are in place.

LEI recommendations – Issue 17

Consistent with the OEB's existing policy, the OEB should commit to reviewing the cost of capital policy every five years. The OEB should also maintain the existing trigger mechanisms, including allowing utilities to apply for different cost of capital parameters during their individual rate hearings, as well as triggering a regulatory review through the off-ramp mechanism (which may or may not include a review of the cost of capital parameters and/or capital structure). In the event that a regulatory review is triggered, the utility and/or intervenors should be allowed to submit evidence for the OEB's consideration regarding the extent to which the cost of capital parameters and/or capital structure caused or contributed to triggering the off-ramp. The OEB can then exercise its own judgement (based on the evidence presented) as to whether the cost of capital parameters and/or capital structure are to be included in the regulatory review.

4.18 Mechanics of implementation – frequency for updating cost of capital parameters and/or capital structure of a utility

Issue 18: ***How should any changes in the cost of capital parameters and/or capital structure of a utility be implemented (e.g., on a one-time basis upon rebasing or gradually over a rate term)?***

[407] For example:

- A 2018 analysis by Bank of Canada Staff found the average business cycle in Canada lasts approximately 4.08 years. (Source: Bank of Canada. *Staff Analytical Note: Characterizing the Canadian Financial Cycle with Frequency Filtering Approaches.* 2018)
- According to data from the C.D. Howe Institute Business Cycle Council (i.e., the "*arbiter of business cycle dates in Canada*") dating as far back as 1929, business cycles in Canada have lasted 7.73 years on average (measured as length from peak to peak). (Source: C.D. Howe Institute Business Cycle Council. *Recession Chronology*)

4.18.1 Status quo

Changes in the OEB's cost of capital parameters are implemented once a utility files its cost of service application (i.e., upon rebasing).[408] For example, the OEB's most recent annual cost of capital parameters update, issued on October 31st, 2023, was for use in cost of service and Custom IR rate-setting plans that had an effective date commencing in 2024.[409] LEI understands that under multi-year cost of service or Custom IR plans, the OEB has approved various approaches to setting the cost of capital parameters in the outer years of these multi-year rate plans, including allowing:

- updates for each year;
- forecasts of future parameters; and
- no updates to parameters for certain years beyond the first year.[410]

The OEB reviews the capital structure only upon an application from the utility or other participants, generally during the review of the rebasing application.

4.18.2 Relevant jurisdictional review

Alberta

In Alberta, the AUC updates the ROE annually. The ROE is calculated each November using a formulaic approach and comes into effect in January of the following year. The AUC only updates the deemed equity ratio every five years, at the same time as the AUC's periodic review of the cost of capital policy.[411] The timing of AUC's periodic review of the cost of capital policy is generally aligned with the rate term of the utilities – for example, the next GCOC assessment is expected to occur in 2028 (for the 2029 rate year and beyond); the current rate term (PBR3) for electric and gas distribution utilities is in effect for the 2024-2028 period. Therefore, any changes in the AUC's cost of capital policy resulting from its five-year periodic reviews can typically be implemented on a one-time basis upon rebasing.

British Columbia

In British Columbia, the BCUC issued its most recent GCOC decision on September 5th, 2023. Through that decision, FEI and FBC were directed to submit a compliance filing within 30 days for rates that implemented the approved cost of capital parameters effective January 2023.[412]

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[408] OEB. *EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities.* December 11, 2009.

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

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

[411] AUC. *Determination of the Cost-of-Capital Parameters in 2024 and Beyond (Decision 27084-D02-2023).* October 9, 2023.

[412] BCUC. *Generic Cost of Capital Proceeding (Stage 1), Decision and Order G-236-23.* September 5, 2023.

Australia

In Australia, the AER updates cost of capital parameters every four years and publishes the parameters in its Rate of Return Instrument. The Instrument for the following regulatory period is typically published in December of the fourth year of the current four-year cycle. Then utilities are required to "*submit regulatory proposals in January and also manage administrative practicalities of finalizing regulatory determinations in April and annual pricing proposals*."[413]

4.18.3 Potential alternatives

Given the way in which Issue 18 in the Final Issues List is phrased, there are two alternative approaches for how changes in the cost of capital parameters could be implemented:

1. **status quo (one-time basis upon rebasing):** updated cost of capital parameters could be implemented from the start of the forthcoming period after each utility files its cost of service application, as is the current practice in Ontario; or

2. **gradually over time:** updated cost of capital parameters could be implemented gradually over a utility's multi-year rate term.

4.18.4 Recommendations

LEI is not convinced that the OEB needs to alter the way in which cost of capital parameter updates are implemented and therefore recommends continuation of the current approach. LEI believes it remains appropriate to implement the updated cost of capital parameters upon rebasing, so long as implementation of these changes in this way continues to meet the FRS and does not directly result in rate shock. LEI's recommendation to retain the status quo is consistent with the principles outlined in Section 3.1, particularly promoting the objectives of predictability and stability. With respect to the review of the utility's capital structure, the OEB can continue to do so when there is a significant change in business/financial risks, and upon application by the utility or other participants (see LEI recommendation in Issue 2/Section 4.2.4).

LEI recommendations – Issue 18
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.

[413] AER. Rate of return instrument. Explanatory statement. February 2023. Page 39.

4.19 Mechanics of implementation – approach for updating cost of capital parameters and/or capital structure for utilities in the middle of an approved rate term

Issue 19: ***Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?***

4.19.1 Status quo

The last time the OEB changed its cost of capital policy was in 2009. At that time, the policy was implemented by way of cost of service applications beginning in 2010. It is LEI's understanding that utilities only transitioned to the new cost of capital parameters and capital structure once they filed their cost of service application (i.e., upon rebasing, not in the middle of an approved rate term).[414,415]

4.19.2 Relevant jurisdictional review

See Section 4.18.2 above for relevant jurisdictional review, as Issues 18 and 19 are related. The issue does not arise in the surveyed jurisdictions due to the timing of reviews.

4.19.3 Potential alternatives

Given the way in which Issue 19 in the Final Issues List is phrased, there are two primary alternative approaches for how changes in the cost of capital parameters could be implemented:

1. **status quo (one-time basis upon rebasing):** updated cost of capital parameters could be implemented from the start of the forthcoming period after each utility files its cost of service application, as is the current practice in Ontario; or

2. **during the rate term:** updated cost of capital parameters could be implemented at some point during a utility's multi-year rate term (i.e., before rebasing) upon application.

4.19.4 Recommendations

LEI believes the OEB's current approach of implementing cost of capital parameter and capital structure updates upon rebasing remains appropriate, so long as implementation of these

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[414] OEB. *EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities.* December 11, 2009.

[415] Notably, following the OEB's 2006 decision to set the deemed capital structure at 60% debt and 40% equity for all electricity distributors, the OEB used a staged approach to transition distributors from their existing capital structures to the 60/40 deemed capital structure over the 2008 to 2010 period, to avoid a "*gross mismatch between actual and deemed capital structure.*" Specifically, for distributors with equity at 35% or 45%, the equity component moved in equal increments over 2 years until it reached 40%; for distributors with equity at 50%, the equity component moved in equal increments over 3 years until it reached 40%. (Source: OEB. *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors.* December 20, 2006)

changes in this way continues to meet the FRS and does not directly result in rate shock. As stated by the OEB, "*the same [cost of capital] approach is used for all utilities, and the results are predictable, stable and fully transparent. The general expectation is that the cost of capital parameters will remain unchanged throughout the rate-setting term, typically 5-years*."[416] LEI generally agrees with this position.

However, in instances where the FRS may not be met by waiting to implement the cost of capital parameter and capital structure updates until rebasing, LEI believes parties should be given the opportunity to implement these changes sooner (i.e., before rebasing) upon application. Due to the large number of entities that the OEB regulates, it uses a staggered approach to the timing of rate applications. For example, the OEB expects 9 electricity distributors (or 16% of the 58 electricity distributors that the OEB regulates) to file cost of service/rebasing applications for 2024 rates, 16 (or 28%) for 2025 rates, 10 (or 17%) for 2026 rates, 9 (or 16%) for 2027 rates, and 10 (or 17%) for 2028 rates.[417, 418] Therefore, if the OEB were to implement changes to its cost of capital policy as a result of this GCOC proceeding in 2025, at least 19 electricity distributors would have to wait at least three years before rebasing. If updates to the cost of capital parameters and capital structure result in material changes, waiting this long before implementing the updated parameters may fail to meet the FRS if companies are materially underearning, or harm customers if they are materially overearning.

Therefore, LEI recommends introducing an option to implement cost of capital parameter and capital structure updates prior to rebasing, upon application by an interested party. Eligibility to file such an application would depend on two factors:[419]

- first, the utility should have more than 60% of its rate term remaining (e.g., at least 3 years of a five-year rate term remaining);[420] and
- second, changes in the cost of capital parameters should be material, deviating from the values currently used by the utility by 100 bps or more.[421]

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416 OEB. *Handbook for Utility Rate Applications.* October 13, 2016.

417 OEB. *2024 electricity distribution rate applications.*

418 OEB. *Applications for 2025 Electricity Distribution Rates.* December 15, 2023.

419 These eligibility criteria should apply to all utilities, regardless of the IR option used.

420 LEI is of the view that this condition ensures that the eligible utility is early enough in its rate term to imply that the FRS is not being met, and hence trumps the costs associated with administrative burden. Towards the end of the rate term, it makes more administrative sense to address utility concerns in the next rate proceeding.

421 The OEB has set different materiality thresholds depending on the context. For example, in the context of cost of service applications for electricity distributors, the OEB requires applicants to provide justification for any material amounts and annual variances – the materiality threshold for distributors with a revenue requirement less than or equal to $10 million is $10,000 for distributors with less than 30,000 customers or $50,000 for distributors with 30,000 or more customers; for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million, the materiality threshold is 0.5% of the revenue

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.

its rates were set.[425] The prescribed interest rate for DVAs equals the 3-month bankers' acceptance rate plus a fixed spread of 25 bp; and

- **construction work in progress ("CWIP"):** the prescribed interest rate for CWIP equals the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate yield.[426] This rate applies to all projects under construction, regardless of the construction period.

The prescribed interest rates are reviewed quarterly and are only updated if the formulaic approach results in a change in interest rates of 25 bp or more; otherwise, the previous quarter's prescribed interest rate is maintained for the following quarter.[427]

In terms of the timing of the interest rates determination, the 3-month actual BA rate at the end of the month that is one month prior to the start of the quarter (e.g., November 30th for quarter starting January 1st), plus a 25 bps fixed spread, is obtained prior to the quarter commencing and is published on the OEB website shortly thereafter effective for the next quarter (e.g., January 1st to March 31st). For the CWIP interest rates, the same procedure is followed to determine and publish the All Corporate rate, except that no spread is added (given that this rate already includes a corporate spread).[428]

4.20.2 Relevant jurisdictional review

Alberta

In Alberta, the AUC's *Rule 023: Rules Respecting Payment of Interest* establishes the means through which a utility can "*recover interest costs resulting from regulatory lag or where revenue forecasts differ from actual results*."[429] Specifically, Rule 023 applies to "*outstanding balances and adjustments of rates, tolls or charges and any other costs that are subject to the [AUC]'s jurisdiction*."[430] Under the rule, interest is calculated from the date a balance is outstanding using simple interest at the BoC policy

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[425] As described previously in Section 4.2.1, a deferral account tracks the cost of a project or program that the utility could not forecast when its current rates were set. When the costs are known, the utility can request OEB approval to recover the costs in future rates. A variance account tracks the difference between the forecast cost of a project or program, which has been included in rates, and the actual cost. If the actual cost is lower (or higher), the utility may request OEB approval to return the difference to customers as a credit (or to recover the difference through rates).

[426] The effective term for the FTSE Canada Mid Term Bond Index All Corporate is 7.21 years. (Source: FTSE Russel. *FTSE Canada Fixed Income.* Closing figures for June 4, 2024)

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

[428] Ibid.

[429] AUC. *Rule 023 related information.* March 1, 2022.

[430] AUC. *Rule 023: Rules respecting payment of interest.* March 1, 2022.

rate (i.e., the rate established by the BoC at which major financial institutions borrow and lend one-day or overnight funds among themselves) plus 1.75%.[431, 432]

British Columbia

In British Columbia, FEI and FBC (collectively FortisBC)'s current multi-year rate plan (for 2020 through 2024) includes flow-through deferral accounts to "*capture the annual variances between the approved and actual amounts for those revenues and costs that are included in rates on a forecast basis.*"[433] These include both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in the rate base and hence earn a rate base return, whereas non-rate base deferral accounts are outside of the rate base, subject to BCUC approval, and attract a weighted average cost of capital ("WACC") return.[434] FortisBC requested similar deferral account treatment in its multi-year rate plan application for the 2025 through 2027 period.[435]

4.20.3 Recommendation/Is the status quo appropriate?

The prescribed interest rate for DVAs is equal to the 3-month bankers' acceptance rate plus a fixed spread of 25 bps. Notably, the 3-month BA rate is also used in the calculation of the DSTDR (see Section 4.4). As discussed previously in the context of the DSTDR calculation, the 3-month BA rate will soon be wound down – the major Canadian banks will not be issuing BAs after the cessation of the Canadian Dollar Offered Rate ("CDOR")'s publication in June 2024. Therefore, due to data availability issues going forward, the calculation methodology for the prescribed interest rate for DVAs will need to be changed. We explore this issue in further detail below.

LEI recommendations – Issue 20
Due to the winding down of the 3-month BA rate, the current methodology for determining the prescribed interest rate for DVAs is no longer feasible (the current methodology for CWIP should be retained). Therefore, LEI recommends changes to the calculation methodology as discussed further below in relation to Issue 21. LEI also explores potential alternatives for determining the prescribed interest rate for the CWIP account in Issue 21 below.

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431 Ibid.

432 The AUC had previously used the BoC bank rate plus 1.5%, but switched to the BoC policy rate plus 1.75% in 2022 so as to "*continue to use an easily accessible and publicly available risk-free rate*" that "*is a reasonable proxy for a short-term risk-free rate to be used when calculating the payment of interest*." The spread was increased from 1.5% to 1.75% to "*keep the total rate the same*." (Source: AUC. *Stakeholder comments on proposed changes to Rule 023: Rules Respecting Payment of Interest.* February 24, 2022)

433 BCUC. *FortisBC Energy Inc. and FortisBC Inc. – Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024 (Decision and Orders G-165-20 and G-166-20).* June 22, 2020.

434 Ibid.

435 FortisBC. *FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC) Application for Approval of a Rate Setting Framework for 2025 through 2027.* April 8, 2024.

4.21 Prescribed interest rates – recommended changes to existing methodology

Issue 21 in the Final Issues List is stated in the textbox below.

> Issue 21: ***If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?***

4.21.1 Potential alternatives

As part of the 2006 proceeding that established the current calculation methodology for the prescribed interest rates, the OEB considered and evaluated several alternatives before deciding on the current approach.

Specifically, as described previously in Section 2, OEB staff had initially proposed a prescribed one-year interest rate for DVAs (based on the one-year Canada treasury bill) plus a corporate spread, arguing that "*a short-term interest rate is appropriate due to the temporary nature of the accounts to which they relate and disposition of account balances in rates over a relatively short period of time*."[436]

For CWIP, OEB staff proposed a two-tiered approach, stating that "*some utilities who use short-term financing during the construction phase, replace it with mid-term financing when the completed asset is placed in service. Other utilities finance construction as part of their general borrowing program or from equity*."[437] However, calculating a blended rate on a utility-specific basis was found to be "*burdensome for utilities to constantly determine this rate for their utility, and monitoring [all regulated utilities'] individual rates is not practical for the Board*."[438] As such, OEB staff proposed using two market-based proxy rates depending on the length of the construction period:[439]

- for construction projects up to one year in length, OEB Staff proposed using interest rates based on the one-year Canada treasury bill rate; and
- for construction projects more than one year in length, OEB Staff proposed using interest rates based on the FTSE mid-term index.

Ultimately, the OEB opted for different proxy rates in its 2006 decision, as described previously in Section 4.20. For DVAs, the OEB approved a shorter-term interest rate equal to the 3-month BA rate plus a fixed spread of 25 bps. For CWIP, the OEB rejected the two-tiered approach and instead approved an interest rate equal to the FTSE mid-term index, to apply to all projects under

436 OEB. *EB-2006-0117, Board Staff Proposal Paper: Interest Rates for Regulatory Accounts of Utilities.* May 26, 2006.

437 Ibid.

438 Ibid.

439 Ibid.

construction, regardless of the construction period. OEB approved this approach for CWIP "*for ease of administration and record keeping by users*."[440]

With this context in mind, LEI believes there are several alternatives for the prescribed interest rate applied to DVAs:

1. **align approach with LEI's recommended calculation methodology for DSTDR:** considering the transition away from BA products and CDOR reference rates, the status quo approach is no longer feasible. One alternative would be to align the prescribed interest rate for DVAs with the approach recommended by LEI for determining the DSTDR – namely using the average of the 3-month CORRA futures rates for the next 12-month period i.e., the average of implied rate for all four quarters of the subsequent year based on data as of September 30th, with the spread for a R1-low rated utility over CORRA to be determined from an annual confidential survey of banks (slightly modified from status quo vis-à-vis a larger sample size of 6-10 banks and limited exclusion of outliers) – see Section 4.5 for further details;

2. **align approach with LEI's recommended calculation methodology for DSTDR, but maintain the fixed 25 bps spread currently used for the prescribed interest rate applicable to DVAs:** instead of basing the spread on an annual confidential survey of banks, as is done in the determination of DSTDR, the OEB could maintain the spread for the prescribed interest rate applicable to DVAs at 25 bps. However, the fixed 25 bps spread is based on an outdated analysis of historical spreads over the 2001-2006 timeframe.[441] LEI notes that the spread for the DSTDR was previously fixed at 25 bps as well, but was revised to be based on the confidential bank survey in 2009; or

3. **use one of the other approaches presented previously in Section 4.5 in the context of the DSTDR calculation (although these alternatives were not ultimately recommended by LEI):** this included using CORRA as a reference rate, plus a spread determined based on a survey either of banks or regulated utilities.

As for the prescribed interest rate applied to CWIP, LEI suggests the following alternatives:

1. **status quo:** the OEB could maintain the prescribed interest rate for CWIP at the FTSE Canada Mid Term Bond Index All Corporate yield;

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

[441] In implementing the fixed 25 bps spread, the OEB stated that: "*[a]n analysis was done to compare the staff proposed rate on regulatory accounts, the one-year Canada T-bill rate plus a corporate spread of the three-month corporate paper rate over the 90-day T-bill rate, to the three-month bankers' acceptance rate. (Rates were taken from the Bank of Canada's website.) Over the period from 2001 to mid-2006, an average difference of 27 basis points existed between the two rates. Therefore, it can be concluded that a standard bankers' acceptance rate as posted on the Bank of Canada website plus a static spread of 25 basis points, will approximate the rate proposed by staff over time*." (Source: OEB. *Approval of Accounting Interest Rates Methodology for Regulatory Accounts (Board File No. EB-2006-0117).* November 28, 2006)

2. **two-tiered approach:** the OEB could establish a short-term and long-term interest rate depending on the construction period, as proposed by OEB Staff in the 2006 proceeding. However, at that time, stakeholders were generally of the view that this approach would be too burdensome for utilities to administer, as it would "*entail having to make assumptions on the life expectancy of projects and potential adjustments when these assumptions are changed in addition to having to maintain separate and more detail [sic] records*";[442]

3. **WACC approach:** the OEB could set the prescribed interest rate for CWIP based on WACC, using the deemed capital structure and applying the ROE to the equity component and the FTSE Canada Mid Term Bond Index All Corporate yield to the debt component. However, as stated by OEB Staff, "*the Board has never approved an equity component with respect to an allowance for interest on construction work in progress*."[443]

4.21.2 Recommendations

LEI's recommendations, detailed in the textbox below, are based on achieving several objectives. First, the cost of capital policy framework should be internally consistent, such that the calculation methodologies across different parameters should be aligned where possible. This promotes transparency and ease of understanding of the policy among stakeholders, consistent with the principles outlined by LEI in Section 3.1. Second, the calculation methodologies should consider findings made by the OEB in previous decisions – therefore, if a two-tiered rate was deemed to be overly burdensome in previous proceedings, and an equity component has never been approved for the interest on CWIP, then absent any contrary evidence, the calculation methodologies should continue to uphold these views.

LEI recommendations – Issue 21

- For DVAs, LEI recommends aligning the prescribed interest rate with the revised calculation methodology recommended by LEI for the DSTDR – namely:
  - For the reference rate, LEI recommends considering the average of 3-month CORRA futures rates for the next 12-month period.
  - The spread for a R1-low rated utility over CORRA should be determined from an annual confidential survey of banks (slightly modified from status quo vis-à-vis a larger sample size of 6-10 banks and limited exclusion of outliers).
- For CWIP, LEI recommends continuing the current approach of basing the prescribed interest rate on the FTSE Canada Mid Term Bond Index All Corporate yield for all construction projects, regardless of duration. LEI also recommends continuing the current CWIP accounting procedures as set out in Article 220 (p. 200) and Article 410 (p. 27-28) of the OEB's *Accounting Procedures Handbook for Electricity Distributors*.

[442] Ibid.

[443] OEB. *EB-2006-0117, Board Staff Proposal Paper: Interest Rates for Regulatory Accounts of Utilities.* May 26, 2006.

4.22 Cloud computing deferral account – appropriate carrying charges for cloud computing deferral account

Issue 22: ***Should carrying charges and/or another type of rate apply to the Cloud Computing deferral account?*** *If so, what rate should be applied?*

The OEB would like to determine if the risk profile of the transition to cloud computing solutions warrants an additional risk premium over and above the carrying charges, i.e., a higher rate than the prescribed interest rates, which is currently allowed to the cloud computing deferral account.[444] However, the OEB also noted that if the OEB determines that carrying charges other than the prescribed rates will apply to the account, any carrying charges that have accrued will be reversed in favour of the final approach.

4.22.1 Status quo

Effective December 1st, 2023, per the Accounting Order (003-2023), the OEB implemented a generic deferral account that records the incremental costs of cloud computing implementation. The recorded costs are subject to OEB's approval in the utilities' respective subsequent rate proceedings for each utility.[445] Incremental costs are costs outside of what is embedded in rates i.e. when amounts are recorded, they should represent impacts that are more than what utilities are already compensated for.[446]

Utilities are required to record incremental OM&A costs and incremental capital costs associated with cloud computing implementation separately. The disposition of recorded costs will be subject to review by the OEB in the utility's next rebasing (cost of service or Custom IR) rate proceeding.[447] The OEB will also allow utilities that are in an extended incentive rate-setting period (e.g. under a deferred rebasing period arising from utility consolidations or under Annual Incentive Rate-setting (IR) Index) to request significant account balances for disposition in a non-rate rebasing year to address potential intergenerational inequity concerns, if warranted. The OEB has stated that only *material* costs will be allowed to be disposed of and that materiality will be assessed at the project level.[448]

The period of cost recovery is intended to align with the initial term of the computing contract. However, the OEB has provided utilities flexibility to propose a different disposition period when they bring the account for disposition.[449] Carrying charges at the OEB's prescribed rates for DVAs

[444] OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

[445] Ibid.

[446] OEB. Q&A: Cloud computing implementation. Costs generic deferral variance account. February 15th, 2024.

[447] OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

[448] OEB. Q&A: Cloud computing implementation. Costs generic deferral variance account. February 15th, 2024.

[449] Ibid.

will apply to the account (unless otherwise directed by the OEB).[450]

Prior to the cloud computing accounting order, the OEB did not distinguish the accounting treatment for cloud computing related operating/capital expenses and general operating/capital expenses.

4.22.2 Relevant jurisdictional review

Alberta is considering allowing the same return as the rest of the regulated asset base for operating costs associated with cloud-based solutions on a pilot basis. BC allows a return equal to the weighted average cost of actual debt on the 'Cloud Costs Regulatory Account'. NY allows utilities to capitalize cloud-based software services to their regulated rate base.

Alberta

The AUC recognizes that IT service providers are moving towards cloud-based solutions, the cost of which may not be capitalized, and that the solutions replace traditional IT products that were previously capitalized. For the purpose of incentivizing distribution utilities to achieve least-cost solutions and minimize any capital bias, which ultimately provides a *long-term benefit to ratepayers by lowering costs in situations where operating solutions are more cost-effective than capital solutions*, the AUC accepts applications from distribution utilities to *earn a return on operating solutions on a pilot basis* during the PBR3 term.[451] The AUC is *interested in exploring* elements of a deemed capital additions approach recommended by ENMAX Power Corporation ("ENMAX"), over the PBR3 term.[452,453] The deemed capital additions approach includes variations on payment terms and recovery of costs as illustrated in Figure 56 below. As such, the AUC stated that it will consider applications from distribution utilities to earn a return on operating solutions on a pilot basis.

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450 OEB. Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs. November 2nd, 2023.

451 AUC. Decision 27388-D01-2023. 2024-2028 Performance-based regulation plan for Alberta electric and gas distribution utilities. October 4th, 2023. Page 74.

452 Ibid.

453 LEI was the consultant to ENMAX in the PBR3 proceeding.

Figure 56. Options with deemed capital additions approach

Approach	Payment terms	Return on expenditure	Amortization
Pre-paid or partially pre-paid	Contract pre-paid or partially pre-paid	Same return as rest of regulated asset base	At end of PBR term, unamortized part of contract would be included in subsequent PBR term's regulated asset base
Partial-amortization	Contract paid annually	Same return as rest of regulated asset base	Amortization is enabled until the end of the contract
Margin-based	Contract paid annually	Fixed adder	N/A

Source: AUC. Decision 27388-D01-2023. 2024-2028 Performance-based regulation plan for Alberta electric and gas distribution utilities. October 4th, 2023. Page 73.

A distribution utility must apply on a per-project basis. The application must relate to a scope of work not covered by an existing arrangement and replace a corresponding capital solution. The utility is required to demonstrate the reasonableness of the proposed operating costs.[454]

British Columbia

In November 2022, British Columbia Power Authority ("BC Hydro") filed an application with the BCUC seeking approval of the Cloud Costs Regulatory Account which would record: 1) variances between the forecast and actual Cloud Arrangements implementation operating costs (i.e. one-time, upfront implementation costs), and 2) variances between forecast and actual unplanned annual usage fee for Cloud Arrangements.[455]

With respect to the implementation operating costs, BC Hydro noted that IFRS requires the costs to be recognized as operating expenses in the year they are incurred, rather than being recovered over the life cycle. *As the implementation costs were not planned as operating costs, BC Hydro would not recover the actual implementation operating costs from ratepayers in the absence of the Cloud Costs Regulatory Account*.[456]

Similarly, under IFRS, annual usage fees are also recognized as operating expenses when incurred. Since Traditional Computing does not consider annual usage fees for forecast IT projects, when an IT project is initially planned as Traditional Computing but is later determined to be a Cloud Arrangement, the incremental annual usage fees would not be recovered from ratepayers in the absence of the Cloud Costs Regulatory Account.[457]

In April 2023, the BCUC approved the deferral of these costs and directed BC Hydro to establish separate deferral accounts for the costs. Specifically, the BCUC approved:[458]

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[454] AUC. Decision 27388-D01-2023. 2024-2028 Performance-based regulation plan for Alberta electric and gas distribution utilities. October 4th, 2023. Page 74.

[455] BCUC. Order G-85-23. Application of approval of cloud costs regulatory account. April 18th, 2023.

[456] Ibid. Appendix A. Page 2.

[457] BCUC. Order G-85-23. Application of approval of cloud costs regulatory account. April 18th, 2023.

[458] Ibid. Page 3.

1) The establishment of the Cloud Costs Regulatory Account, *attracting interest at BC Hydro's weighted average cost of debt*, to defer the forecast Cloud Arrangements implementation operating costs and the variance between forecast and actual Cloud Arrangements implementation operating costs as an intangible asset, and to amortize the forecast Cloud Arrangements implementation operating costs over the remaining life cycle for each implementation; and
2) The establishment of a separate regulatory account for Cloud Arrangements annual usage fees, *attracting interest at BC Hydro's weighted average cost of debt*, to defer any variance between the actual annual usage fees for unplanned Cloud Arrangements and the cost-saving related to forecast maintenance and support costs associated with the planned Traditional Computing capital project, and to amortize the annual usage fee variances over the next Revenue Requirement Application[459] ("RRA") test period.[460]

New York

In May 2016, the NYPSC issued a declaratory statement in its Reforming the Energy Vision ("REV") Track 2 Order, which enables utilities to capitalize cloud-based software services. Many businesses have found it *more efficient to enter contracts to lease software services over extended periods*, rather than developing their own software.[461] When pre-paying the total cost of a service contract, a utility can record the unamortized balance of the pre-payment as a regulatory asset, to be included in its rate base and earn a return.[462]

A summary of the jurisdictional review is shown in Figure 57 below.

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[459] RRA is an application including various approvals sought by BC Hydro from the BCUC, such as approval of rates, revisions to or request for new regulatory accounts, the setting of depreciation rates, approval of expenditure schedules, etc. Source: BC Hydro. Revenue requirements. Accessed May 27th, 2024.

[460] BCUC. Order G-85-23. Application of approval of cloud costs regulatory account. April 18th, 2023. Page 3.

[461] New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (Case No. 14-M-0101).* May 19, 2016. Page 104.

[462] Ibid.

Figure 57. Summary table of the jurisdictional review on Issue 22

Jurisdiction	Cloud computing accounting treatment
Alberta	• The AUC accepts applications from distribution utilities to earn a return on operating solutions on a pilot basis during the PBR3 term • The return is determined using the deemed capital additions approach with three options: pre-paid or partially pre-paid, partial amortization, and margin-based • A distribution utility must apply on a per-project basis • The proposal must relate to a scope of work that is not covered by an existing arrangement and replace a corresponding capital solution
BC	• The BCUC directed BC Hydro to establish separate deferral accounts, earning an interest at BC Hydro's weighted average cost of debt, for o Cloud Arrangements implementation operating costs: amortized over the remaining life cycle of each implementation o Cloud Arrangements annual usage fees: amortized over the next RRA test period
NY	• The NYPSC allows a utility to record the unamortized balance of the pre-payment of cloud-based solutions as a regulatory asset which is included in its rate base and earn a return

4.22.3 Potential alternatives

The OEB may choose from one of the following options:[463]

1. Status-quo approach; and
2. Allow carrying charge based on deemed WACC for the unamortized portion of the cloud computing contract.

1. Status-quo approach

The OEB may continue to apply the prescribed interest for DVAs to the cloud computing deferral account, i.e., the same allowed carrying charge/interest rate as other DVA accounts.

2. ***Allow carrying charge based on deemed WACC for the unamortized portion of the cloud computing contract***

Under this approach, the OEB can allow the prescribed interest rate for the DVAs on the incremental operating costs. The recorded incremental operating costs and the relevant costs allowed during IRM proceedings (if any) can be treated as *amortized* costs of the cloud computing contract. The OEB can treat the balance *unamortized* portion of the cloud-based contracts (contract

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[463] LEI has not presented the margin-based fixed adder option (described in Figure 46) as an alternative due to additional complexities associated with determining an appropriate margin each year and incompatibility with the prevailing Ontario practice of recording incremental costs in a cloud computing deferral account. However, LEI is broadly supportive of such an approach for "capital as a service".

value minus amortized costs) as deemed capital additions to incentivize the transition to cloud-based software solutions. The onus should be on the utilities to justify the claimed costs during rebasing.

A deemed WACC (based on allowed capital structure, ROE, DLTDR and DSTDR, and determined as of the year of rebasing or the year of disposition, for the remaining term of the contract) for all utilities may be allowed on the deemed capital additions.[464] In addition, if the recorded incremental capital costs are not yet capitalized, the OEB may consider allowing the prescribed interest rate for the CWIP account on the recorded incremental capital costs until it is capitalized and added to the rate base.

The associated costs can be added to customer rates during the disposition of recorded costs.

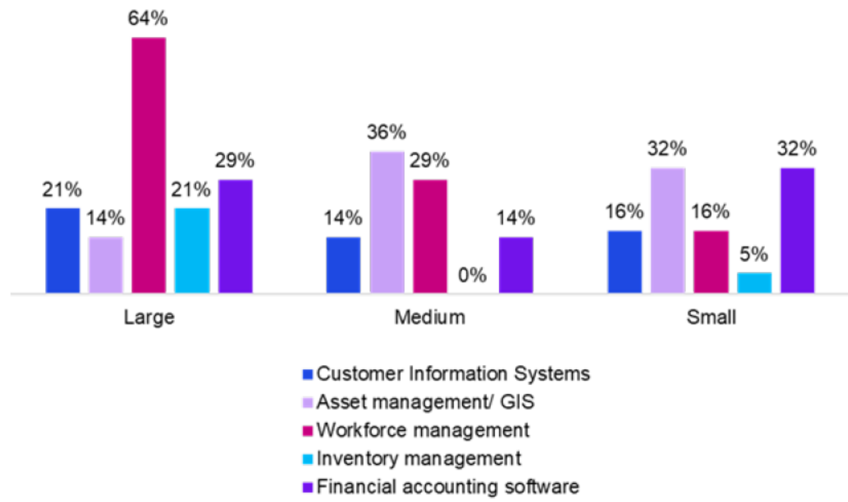
4.22.4 Recommendations

Changes in technology and industry structure have created the possibility that activities previously enabled by capital investment can be provided through contractual arrangements. However, utilities are disincentivized from pursuing such arrangements because doing so removes activities on which the utility earns a return from the rate base and treats them as operating expenses on which they do not earn a return. LEI believes that cloud computing is less risky compared to in-house investments, however, a deemed WACC is necessary as a means of aligning incentives for utilities to transition to cloud computing solutions.

This can act as a barrier to transition to cloud computing solutions despite being more cost effective over a longer time horizon. The increased risks of transition to cloud-based solutions are associated with foregone revenue from the capital investments in in-house server solutions. This reluctance to transition is reflected in the share of Ontario utilities that have transitioned to cloud-based solutions (see Figure 58).

[464] For example, if the cloud computing deferral account is brought forward for disposition in a non-rebasing rate year, LEI recommends that the ROE, DLTDR and DSTDR applicable for the year of disposition may be utilized to determine the deemed WACC.

Figure 58. Adoption of cloud-based solutions by OEB-regulated utilities



Source: OEB. Appendix B to Accounting Order (003-2023). KPMG Report on regulatory options for the treatment of cloud computing costs. September 2023. Page 26.

LEI recommends that the OEB employ a deemed capital additions approach (Alternative #2 in Section 4.22.3) to increase utility flexibility and align incentives with customers. This approach will be beneficial in reducing a utility's capital bias as the utility will theoretically earn the same return if it were making capital investments in in-house IT infrastructure. The LEI recommendation is intended to be applied as a default procedure in circumstances where the utilities have not specifically referenced cloud computing in their previous rebasing applications. This should not prevent the utilities from proposing an alternate regulatory treatment for OEB's consideration when filing rebasing applications. Similar approaches can be used for other capital as a service arrangements.

LEI recommendation – Issue 22

- LEI believes a deemed WACC is necessary as a means of aligning incentives for utilities to transition to cloud computing solutions
- LEI recommends that the OEB employ a deemed capital additions approach, which allows deemed WACC on the unamortized portions of the cloud computing contracts.

5 Concluding remarks

LEI reviewed the 22 issues identified by the OEB in the Generic Proceeding. For each issue, LEI reviewed the status quo in Ontario and the practices followed in other jurisdictions and/or literature review. LEI has presented several options for the OEB and other participants to consider based on the aforementioned review. LEI evaluated the presented alternatives and made a recommendation for each issue based on five guiding principles:

1. ***Meeting the FRS***, which is a legal requirement;

2. ***Simple to administer relative to the status quo***, i.e., the costs (if any) of transitioning away from the status quo and administering the recommended alternative are reasonable;

3. ***Transitioning away from the status quo only if the associated benefits are material*** as there is limited merit in modifying aspects of the methodology that have worked well;

4. ***Fairness in approach to consumers and utilities***, consistent with the OEB's mission and mandate, to ensure efficient investments; and

5. ***Predictability and transparency*** in the recommended approach to ensure that the outcomes from the proposed methodology are relatively stable over a long-term time horizon.

Overall, LEI's recommendations are a mix of retaining the status quo and making incremental/evolutionary improvements to the current approaches. Key changes recommended by LEI are described below:

- Determine base ROE using CAPM (average estimate of 8.95%, low estimate of 8.23%, and a high estimate of 10.22%) instead of the ERP approach used in 2009, as CAPM provides a more accurate picture of returns required by equity investors (see Section 4.10);

- The ROE to 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);

- Change the DSTDR reference rate to CORRA futures, as the BoC intends to phase out BA-based lending products by June 28th, 2024 (see Section 4.4 and Section 4.5);

- DLTDR and DSTDR to be applicable as a cap for all utilities (not just electricity distributors and transmitters), as OEB-regulated entities have similar short-term and long-term credit ratings (see Section 4.5 and Section 4.7);

- Mandate forward-looking cash flow scenario analysis and impact on key credit metrics when reviewing capital structure/equity thickness (see Section 4.12);

- Link the interest rate allowed for DVAs to the recommended DSTDR (see Section 4.21); and

- A deemed capital additions approach to be utilized for operating expenses associated with cloud computing contracts, which allows deemed WACC on the unamortized portions of the cloud computing contracts (see Section 4.22).

Ontario's existing regulatory regime is viewed favorably by investors (as seen in credit rating assessments by major rating agencies and actual debt/equity issuances). LEI believes its recommended changes will enable the OEB to maintain its investor-friendly status while retaining fairness to consumers.

6 Appendix A: Details of jurisdictional review

6.1 Alberta

Alberta has a population of approximately 4.8 million[465] with a total electricity demand of 86 TWh[466] in 2023. The AUC regulates 21 electric and gas utilities.[467] It determines ROE that meets the FRS using a formulaic approach uniformly applied to the electricity and natural gas sectors and sets deemed capital structures at its own discretion after consulting with utilities and experts. Moreover, the AUC reviews the formulaic approach and the deemed capital structure every five years, subject to mid-term reopeners, and updates the allowed ROE annually.[468]

Prior to 2004, the AUC considered the cost of capital parameters for each utility on a case-by-case basis. In 2004, the AUC set a generic ROE for all utilities and adopted an automatic adjustment formula to update the ROE annually. The approach was applied from 2005 to 2008 and discontinued in 2009 due to the global financial crisis. From 2009 to 2022, the AUC set the ROE based on economic and financial evidence filed by parties, following intensive regulatory processes, instead of on the formulaic approach.[469] In January 2022, the AUC initiated a process with two stages to determine ROE and deemed equity ratios: the first stage established the cost of capital parameters for 2023 based on economic and financial evidence, and the second stage established a formulaic approach for setting ROE in 2024 and beyond, which the AUC currently uses.[470]

The historical ROE and deemed equity ratios are illustrated in Figure 59 and Figure 60.

465 Government of Alberta. Current provincial population estimates. Accessed on April 24th, 2023.

466 Alberta Electricity System Operator. 2024 Long term outlook decarbonization scenario modeling dashboard. Aceesed on April 22nd, 2024.

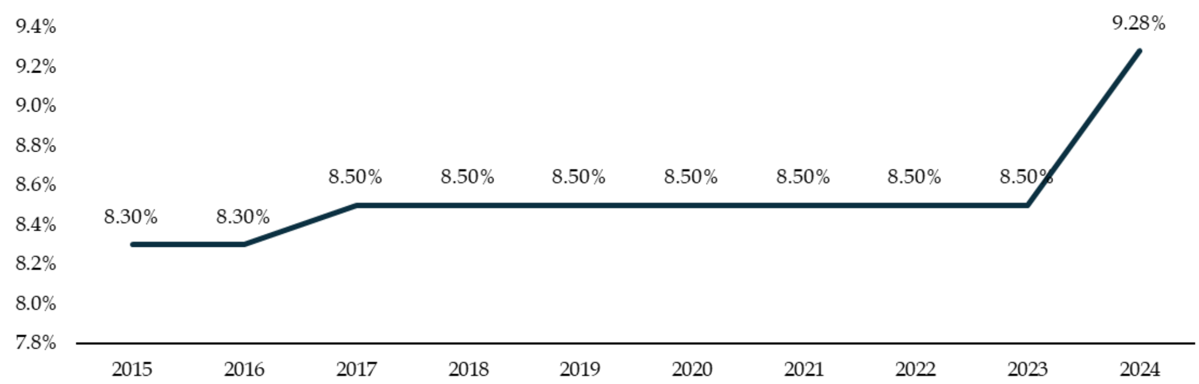
467 AUC. Investor and municipally owned utilities companies. Accessed on April 22nd, 2024.

468 AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023.

469 AUC. Decision 27084-D01-2022. 2023 Generic cost of capital. March 31st, 2022.

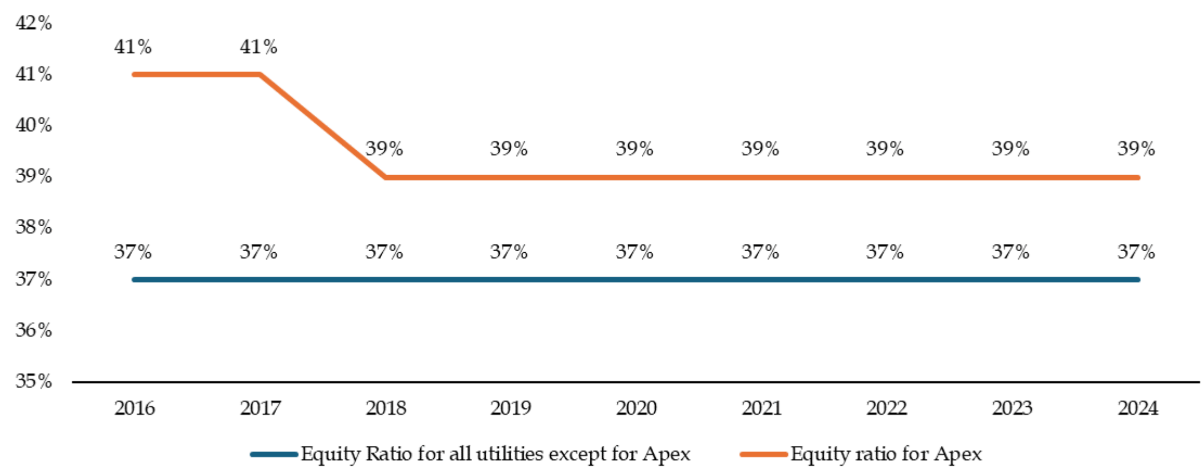
470 AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023.

Figure 59. Historical ROE set by the AUC



Source: AUC.

Figure 60. Historical deemed equity ratio set by the AUC



Note: The deemed equity ratio varied for utilities in 2015. All transmission utilities had a deemed equity ratio of 36%, except ATCO Pipelines, which had a deemed equity ratio of 37%. The deemed equity ratios for distribution utilities ranged from 38% to 42%.
Source: AUC.

6.2 Australia

Australia has a population of 26.8 million[471] with a total electricity consumption of 188 TWh[472] in 2023. The AER regulates 43 electric and gas service providers.[473] It determines the cost of capital

[471] Australian Bureau of Statistics. National, state and territory population. March 21st, 2024.

[472] AER. Annual electricity consumption – NEM. Accessed on April 24th, 2024.

[473] AER. List of service providers and assets. Accessed on April 22nd, 2024.

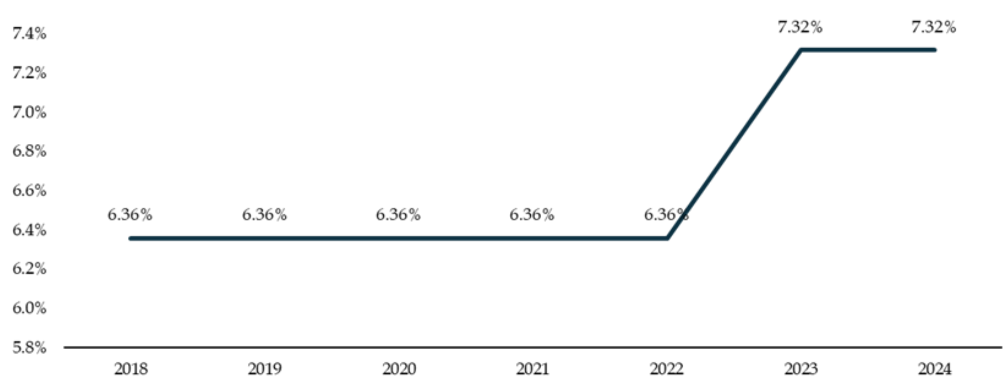
parameters using a formulaic approach, uniformly applied to all sectors. The AER follows the principle of determining *an unbiased estimate of the expected efficient return, consistent with the relevant risks involved in providing regulated network services*.[474] Also, the AUC determines deemed capital structures through a benchmarking approach and examining relevant empirical evidence. The cost of capital parameters and deemed capital structures/gearing ratios are reviewed every four years, with the cost of debt updated annually.[475]

In December 2013, the AER developed a non-binding rate of return guidelines ("the 2013 Guidelines") as part of its Better Regulation reform program. In mid-2017, the AER initiated a review of the 2013 Guidelines. In November 2018, the National Electricity Law and the National Gas Law were amended to replace the non-binding rate of return guidelines with a binding rate of return instrument.[476] In December 2018, the AER published the *2018 Rate of Return Instrument* covering the period of 2019 to 2022, followed by the *Rate of Return Instrument 2022* covering the period of 2023 to 2026.

Moreover, the AER has been transitioning from the on-the-day approach to setting the cost of debt allowance to a trailing average approach since 2013 as set out in the 2013 Guidelines. An on-the-day rate reflects the annual spot cost of debt in the averaging period whereas a trailing average rate reflects ten years of historical return on debt. The transition takes ten years, and the allowed return on debt for each NSP depends on the date when it commenced the transition to the trailing average approach.[477]

The historical ROE, cost of debt, and deemed equity ratios are illustrated below.

Figure 61. Historical allowed ROE set by the AER



Source: AER.

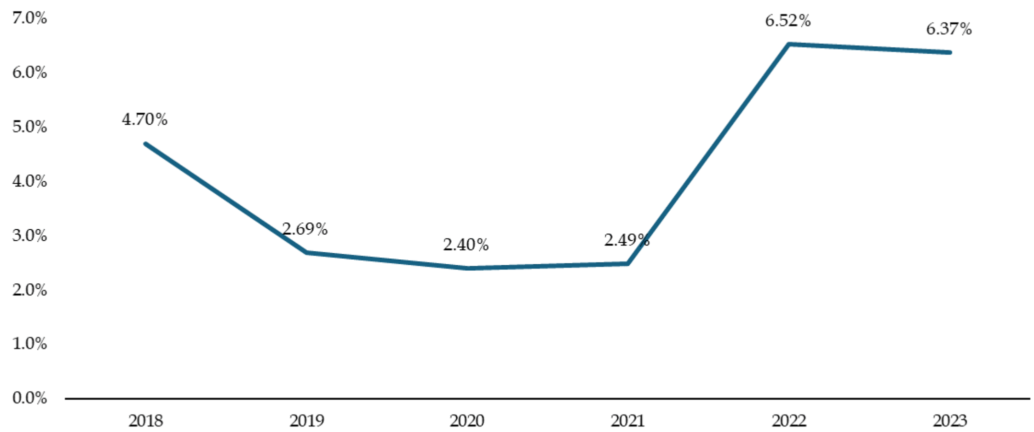
[474] AER. Rate of return instrument. Explanatory statement. February 2023.

[475] Ibid.

[476] AER. Rate of return instrument. Explanatory statement. December 2018.

[477] AER. Rate of return annual update 2023. December 2023.

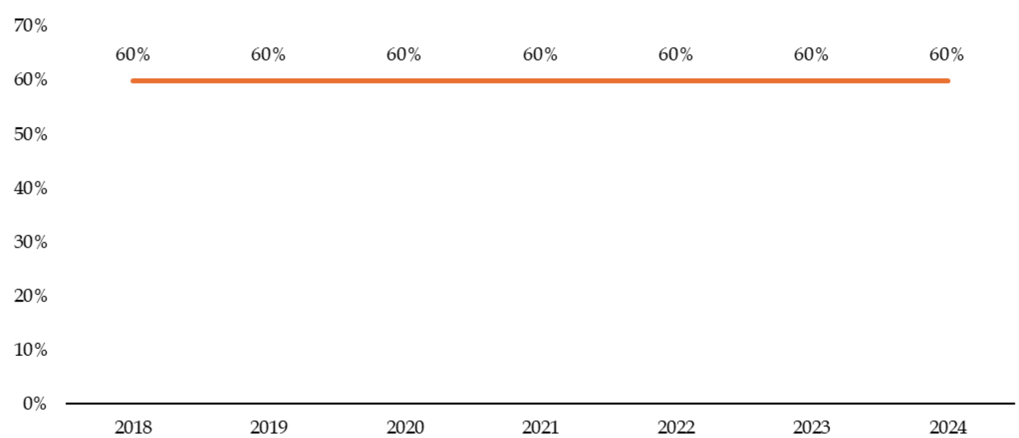
Figure 62. Historical allowed cost of debt set by the AER



Note: The indicative return on debt reflects the on-the-day rate with the averaging period across all business days in December of the respective year (for 2018 and 2022)/August (for 2019-2021, and 2023). Thus, the 2024 data is not available.

Source: AER.

Figure 63. Historical gearing ratio set by the AER



Source: AER.

6.3 British Columbia

British Columbia had a population of 5.5 million[478] as of 2023 with electricity consumption of 65 TWh[479]. The BCUC regulates 18 electric and gas utilities.[480] It applies a benchmark approach to determine cost of capital parameters that meet the FRS and deemed capital structures. It is notable that the BCUC does not set a definitive duration for periodic reviews on cost of capital parameters and deemed capital structures. Instead, it has the power to initiate a review at any time within its discretion, and a utility can apply to the BCUC for a review at any time.[481]

In November 2011, the BCUC issued a *Preliminary Notification of Initiation of a Generic Cost of Capital Proceeding* to all regulated utilities.[482] Later, in February 2012, the BCUC issued Order G-20-12, which established a GCOC proceeding to review the setting of appropriate cost of capital parameters for a benchmark utility and the establishment of a deemed capital structure and deemed cost of capital methodology.[483] In May 2013, the BCUC issued its first GCOC proceeding in which it set the cost of capital parameters and the deemed equity ratio for FEI, the Benchmark Utility, effective 2013.[484] Following a cost of capital review conducted by the BCUC in 2016, in January 2021, the BCUC noted that *significant time had passed* and therefore, issued a Notice of Initiating a GCOC proceeding.[485] The first stage of the proceeding determined the cost of capital parameters for the benchmark utilities, FEI and FBC, and was completed in September 2023. The ongoing second stage will determine matters related to the benchmark utility, *including whether utilizing a benchmark utility remains an appropriate approach and, if so, whether one or both or neither of these utilities should serve as a benchmark for establishing the cost of capital for other utilities*.[486]

The historical ROE, cost of debt, and deemed equity ratios are illustrated below.

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478 Statista Research Department. Population estimates for British Columbia, Canada 2000-2023. March 11th, 2024.

479 BC's electricity consumption per capita in 2019 was 11.8 MWh. Source: Canada Energy Regulator. Provincial and territorial energy profiles – British Columbia. Accessed on April 24th, 2024.

480 BCUC. Regulated entity map. Accessed on April 22nd, 2024.

481 BCUC. Decision and Order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023.

482 BCUC. Order G-72-12. Generic cost of capital proceeding. Final order with reasons. June 1st, 2012.

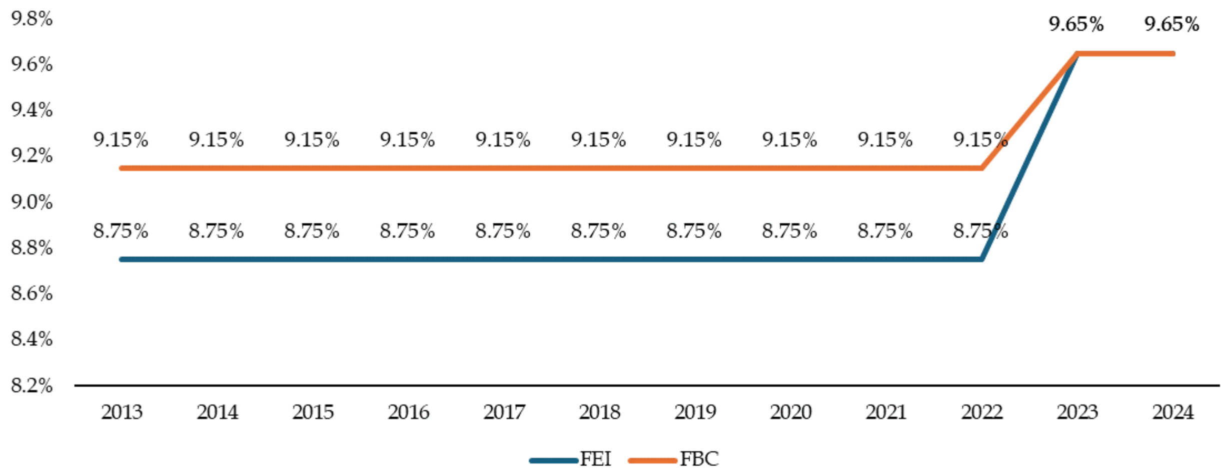
483 BCUC. Order G-20-12. Generic cost of capital proceeding. Final order. February 28th, 2012.

484 BCUC. Order G-75-13. Generic cost of capital proceeding. Final order. May 10th, 2013.

485 BCUC. Decision and Order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. Page i.

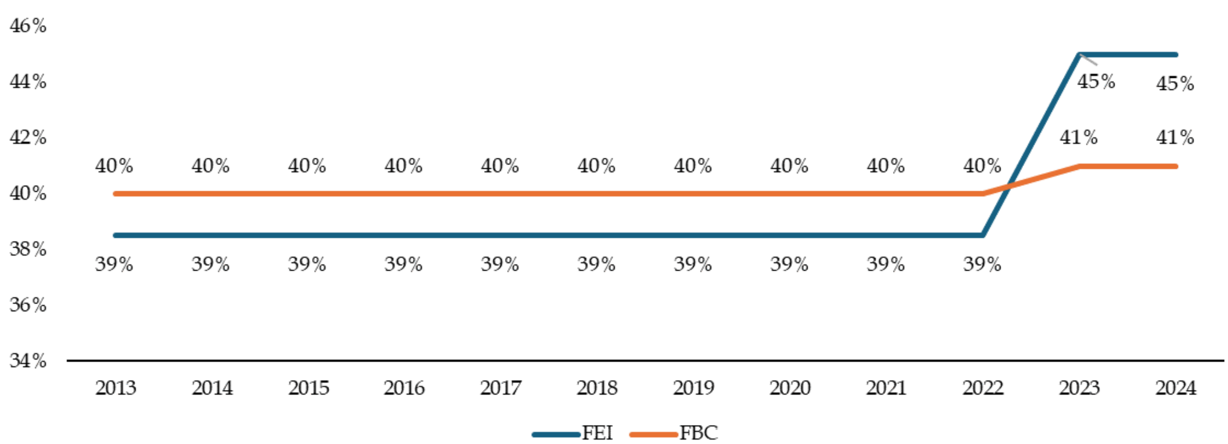
486 Ibid.

Figure 64. Historical allowed ROE set by the BCUC



Source: BCUC.

Figure 65. Historical gearing ratio set by the BCUC



Source: BCUC.

6.4 California

California has a population of 39.1 million[487] with electricity consumption of 288 TWh[488] in 2022. The CPUC regulates 6 electric and gas utilities[489] and abides by the principle of setting *fair and*

[487] State of California. E-2. California county population estimates and components of change by year – July 1, 2022 – 2023. December 2023.

[488] California Energy Commission. Electricity consumption by entity. Accessed on April 23rd, 2024.

reasonable capital structures and ROEs.[490] It is notable that although cost of capital parameters and deemed capital structures are determined on a case-by-case basis for utilities, the CPUC has adopted a uniform multi-year CCM for large utilities[491] ("the Utilities") to automatically adjust their cost of capital parameters since May 2008. The CCM is reviewed every three years.[492]

R.87-11-012 established annual cost of capital proceedings separate from general rate cases for the Utilities effective January 1st, 1990. The CPUC typically determines the cost of capital parameters for the Utilities in a single consolidated proceeding. In 2008, the CPUC determined the CCM for the Utilities that enabled them to file cost of capital applications every three years, rather than annually. The CCM is still in use as of now.

6.5 New York

New York has a population of 19.6 million[493] with electricity consumption of 144 TWh[494] in 2023. The NYPSC regulates 18 electric and gas utilities in total.[495] The NYPSC follows the principle of setting a *fair and reasonable rate of return on capital investments* and determines cost of capital parameters and deemed capital structures on a case-by-case basis.[496] Nevertheless, the NYPSC introduced *Bill A07502* in May 2023 proposing to establish *a single rate of return on equity for all regulated utilities based on the generic financing methodology*.[497] The bill was referred to the Committee on Energy in January 2024 and no further development has been made as of May 31st, 2024.

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489 CPUC. What is a general rate case (GRC)? Accessed on April 23rd, 2024.

490 CPUC. Decision 08-05-035. Decision establishing a multi-year cost of capital mechanism for the major energy utilities. May 30th, 2008.

491 Large utilities include Southern Edison Co., San Diego Gas & Electric Co., and Pacific Gas and Electric Co. Source: CPUC. Decision 08-05-035. Decision establishing a multi-year cost of capital mechanism for the major energy utilities. May 30th, 2008.

492 Ibid.

493 US Energy Information Administration. New York State energy profile. Updated on December 21st, 2023.

494 US Energy Information Administration. Electricity data browser. Accessed on April 23rd, 2024.

495 NYPSC. Complete annual reports of regulated utilities. Accessed on April 22nd, 2024.

496 New York State Assembly. Bill A07502. Updated January 3rd, 2024.

497 Ibid.

6.6 United Kingdom

The UK has a population of approximately 67.6 million[498] with electricity demand of 310 TWh[499] in 2023. Ofgem regulates over 800 electric and gas licensees.[500] It utilizes a price control framework, called the RIIO (Revenues = Incentives + Innovation + Outcomes). The framework ensures *network companies can, through efficient operation, earn a fair return on their activities while controlling the end cost to consumers* and is applied uniformly across energy network sectors.[501] Nevertheless, cost of capital parameters are set separately for utilities in different sectors using slightly varied formulae. Deemed equity ratios/gearing ratios are set at Ofgem's discretion. Moreover, Ofgem reviews the appropriateness of cost of capital parameters' formulae and capital structures every five years, with the cost of debt allowance updated annually.[502]

Ofgem introduced the RIIO framework in October 2010. Under the framework, Ofgem sets the price control for the electric distribution ("ED") sector separate from gas distribution ("GD") and transmission ("T") (including both electric and gas transmission) sectors. However, the RIIO approach to ED is similar to GD and T's approach. In terms of the first price control period ("RIIO1"), in 2013, Ofgem introduced RIIO-1 for the GD and T price controls, covering the period from April 1st 2013 to March 31st 2021[503]; later in 2014, Ofgem published its final determinations for ED ("RIIO-ED1") for the period from April 1st 2015 to March 31st, 2023.[504] For the second price control period ("RIIO2"), in 2020, Ofgem issued RIIO-2 for the GD and T price controls for the period from April 1st 2021 to March 31st, 2026[505]; later in 2022, Ofgem published its final determinations for ED ("RIIO-ED2") for the period from April 1st 2023 to March 31st, 2028.[506]

Figure 66 below demonstrates the cost of capital parameters and gearing ratios set by Ofgem for RIIO2.

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498 Office for National Statistics. Population estimates for England and Wales: mid-2022. November 23rd, 2023.

499 Department for Energy Security & Net Zero. Energy trends: UK, October to December 2023 and 2023. March 28th, 2024.

500 Electric licensees include independent distribution network operators, distribution network operators, electricity transmission, and electricity generation; gas licensees include gas shipper, distribution network operators, retained distribution network operators, independent gas transporters, and national transmission system operator. Source: Ofgem. Lists of licensed companies. Accessed on April 22nd, 2024.

501 Ofgem. Decision. RIIO-2 final determinations – Finance annex (revised). February 3rd, 2021.

502 Ibid.

503 Ofgem. Network price controls 2013-2023 (RIIO-1). Accessed May 31st, 2024.

504 Ibid.

505 Ofgem. RIIO-2 final determinations – Core document. December 8th, 2020.

506 Ofgem. RIIO-ED2 final determinations overview document. November 30th, 2022.

Figure 66. RIIO2 cost of capital parameters and gearing ratios

RIIO2*		2022	2023	2024	2025	2026	2027	Average
GD (Frequent debt issuers**) and GT	Cost of Equity	4.52%	4.53%	4.55%	5.47%	4.59%		4.55%
	Expected outperformance	0.25%	0.25%	0.25%	0.25%	0.25%		0.25%
	Allowed ROE	4.27%	4.28%	4.30%	5.22%	4.34%		4.30%
	Cost of debt	2.05%	1.90%	1.80%	1.71%	1.65%		1.82%
	Notional gearing	60%	60%	60%	60%	60%		60%
GD (Infrequent debt issuers)	Cost of Equity	4.52%	4.53%	4.55%	5.47%	4.59%		4.55%
	Expected outperformance	0.25%	0.25%	0.25%	0.25%	0.25%		0.25%
	Allowed ROE	4.27%	4.28%	4.30%	5.22%	4.34%		4.30%
	Cost of debt	2.11%	1.96%	1.86%	1.77%	1.71%		1.88%
	Notional gearing	60%	60%	60%	60%	60%		60%
ET	Cost of Equity	4.24%	4.24%	4.24%	4.25%	4.26%		4.25%
	Expected outperformance	0.22%	0.22%	0.22%	0.22%	0.22%		0.22%
	Allowed ROE	4.02%	4.02%	4.02%	4.03%	4.04%		4.02%
	Cost of debt	2.05%	1.90%	1.80%	1.71%	1.65%		1.82%
	Notional gearing	55%	55%	55%	55%	55%		55%
ED (Frequent debt issuers***)	Cost of Equity		5.28%	5.20%	5.22%	5.22%	5.22%	5.23%
	Allowed ROE		5.28%	5.20%	5.22%	5.22%	5.22%	5.23%
	Cost of debt		3.04%	3.07%	3.05%	2.99%	2.92%	3.01%
	Notional gearing		60%	60%	60%	60%	60%	60%
ED (Infrequent debt issuers)	Cost of Equity		5.28%	5.20%	5.22%	5.22%	5.22%	5.23%
	Allowed ROE		5.28%	5.20%	5.22%	5.22%	5.22%	5.23%
	Cost of debt		3.10%	3.13%	3.11%	3.04%	2.98%	3.07%
	Notional gearing		60%	60%	60%	60%	60%	60%

Source: Ofgem.

7 Appendix B: Determination of adjustment factors

LEI performed regression analyses using US data to determine the adjustment factors of LCBF and A-rated utility bond yields. In terms of the input, the dependent variable is the weighted average ROE by assigning 0.78 weight to the quarterly average allowed ROEs of US electric utilities and 0.22 weight to the quarterly average allowed ROEs of US gas utilities (weights based 2022 rate base allocation in Ontario). The ROE data is for the period from 2001 to 2023, retrieved from S&P. The independent variables are quarterly US 30-year treasury bond yields from 2001 to 2023 and quarterly Moody's Seasoned Baa Corporate bond yields from 2001 to 2023.

LEI performed regression analyses on the two independent variables separately and the outputs are as follows. The outputs suggest that the adjustment factor for LCBF should be 0.39 and the adjustment factor for A-rated utility bond yields should be 0.33.

Figure 67. Summary output – Allowed ROE vs US 30-year Treasury bond yield

Regression Statistics	
Multiple R	0.770733023
R Square	0.594029393
Adjusted R Square	0.589518609
Standard Error	0.360755429
Observations	92

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	17.13884715	17.13885	131.6909	2.60493E-19
Residual	90	11.71300318	0.130144		
Total	91	28.85185032			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.659456871	0.132369401	65.41887	1.12E-77	8.396481952	8.92243179	8.396481952	8.92243179
x	0.388420481	0.033847313	11.47567	2.6E-19	0.321176886	0.455664075	0.321176886	0.455664075

Figure 68. Summary output – Allowed ROE vs Moody's Baa Corporate bond yield

Regression Statistics	
Multiple R	0.743155835
R Square	0.552280595
Adjusted R Square	0.547305934
Standard Error	0.378851089
Observations	92

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	15.93431705	15.93432	111.0188	2.20826E-17
Residual	90	12.91753327	0.143528		
Total	91	28.85185032			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.271530412	0.179443565	46.09544	2.15E-64	7.915034449	8.628026374	7.915034449	8.628026374
x	0.326327907	0.030971057	10.53654	2.21E-17	0.264798496	0.387857317	0.264798496	0.387857317

LEI also performed a multivariate regression analysis to examine the relationship between the allowed ROE and the US 30-year Treasury bond yield as well as Moody's Baa Corporate bond yield. The output is shown below.

Figure 69. Summary output – Allowed ROE vs US 30-year Treasury bond yield & Moody's Baa Corporate bond yield

Regression Statistics	
Multiple R	0.783710797
R Square	0.614202614
Adjusted R Square	0.60553301
Standard Error	0.353648217
Observations	92

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	17.72088188	8.860441	70.84552	3.91731E-19
Residual	89	11.13096844	0.125067		
Total	91	28.85185032			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.41643924	0.171838025	48.97891	3.69E-66	8.075000744	8.757877736	8.075000744	8.757877736
US 30-year Treasury	0.259045098	0.068538952	3.779531	0.000284	0.12285966	0.395230536	0.12285966	0.395230536
Moody's Baa Corp	0.128829882	0.059719152	2.157262	0.03368	0.010169199	0.247490564	0.010169199	0.247490564

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9 Appendix D: Selected relevant LEI experience

LEI has been active in Ontario since 1998. Toronto is one of the firm's primary offices. Over the past three decades, LEI has performed numerous engagements for the OEB and numerous private and public sector clients. LEI regularly models Ontario wholesale price outcomes using proprietary software.

Furthermore, LEI staff have relevant experience in cost of capital and capital structure matters (including advising on equity thickness), reviewing regulatory dockets and supporting regulatory staff with filing interrogatories. A selection of relevant work is provided below.

9.1 Cost of capital

A sample of relevant engagements are listed below.

- ***Capital structure analysis in Ontario***: LEI was retained by the Ontario Energy Board ("OEB") staff as capital structure expert in respect of Ontario Power Generation ("OPG")'s 2022-2026 Payment Amounts Application (EB-2020-0290). As part of its engagement, LEI assisted in preparing interrogatories; and prepared an independent expert report following a detailed review of the analysis of risks set out in the application on the risks faced by OPG. LEI also responded to interrogatories with respect to its expert report.
- ***Testimony support to OEB in equity thickness review:*** In 2023, LEI was retained by the OEB Staff as capital structure expert in respect of Enbridge Gas Inc.'s application (EB-2022-0200). As part of its engagement, LEI supported OEB Staff in preparing interrogatories for Enbridge's submissions and later testifying as expert witnesses including participation in cross-examination by various intervenors. LEI prepared an independent expert report following a detailed review of the analysis of business and financial risks set out in the application and provided an independent opinion on the appropriate equity thickness for Enbridge Gas Inc. for the 2024-2028 period. LEI also submitted responses to interrogatories received by intervenors.
- ***Assisting in updating cost of capital and inflation parameters for the OEB:*** LEI has been engaged by OEB Staff (since July 2019) to provide quarterly updates on the macroeconomic conditions facing the utility sector in Ontario, and their potential impact on the cost of capital, interest, and inflation parameters. LEI prepared quarterly reports for the 2019-2021 term and the 2021-2023 term of this engagement. LEI then successfully competed in the 2023-2025 solicitation and is currently undertaking this engagement for OEB Staff once again, which includes providing analysis associated with cost of capital and inflation parameters.
- ***Independent expert evidence on ROE for IRAC***: LEI was retained by the legal counsel for the Prince Edward Island Regulatory and Appeals Commission ("IRAC") to provide independent expert evidence on a just and reasonable return on equity ("ROE") for the Maritime Electric Company Limited ("MECL"), associated with their General Rate Application ("GRA") for 2023-2025 [IRAC Docket: UE20946]. For risk-free rate, LEI utilized the US 10-year government bond yield forecasts for the rate period (2023 to 2025),

and the average spread between 10-year and 30-year bond yields to arrive at the 30-year bond yields. For calculation of beta, LEI chose a North American peer group. LEI ensured that the companies in the peer group were representative of the business and financial risks faced by MECL. To estimate beta, LEI utilized a three-step process: (i) first, LEI used the 3-year 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 MECL operating leverage. For determining Equity Risk Premium, LEI analyzed the long-term historical spread between risk-free rate and market returns. LEI also modified the CAPM formula to include a size risk premium as MECL was a significantly smaller company compared to the North American peer group and hence faced higher risks. IRAC allowed the LEI determined ROE of 9.7% as the upper cap for MECL's ROE during the 2023-2025 rate period. [IRAC Docket: UE20946]

- ***Independent technical consultation for a rate case involving Montana-Dakota Utilities Company:*** LEI was engaged by the North Dakota Public Service Commission as the outside independent technical consultant supporting the Commission's ratepayer advocacy staff in a rate case involving Montana-Dakota Utilities Company. LEI examined key components of the rate case, which included the depreciation study, tax rates, environmental upgrades, transmission investment, the ROE/common equity ratio, amortization for early retirement of coal plants, and impacts on residential rates versus impacts on other classes of service. [Case No. PU-22-194]

9.2 Selected PBR proceedings

A sample of relevant engagements are listed below.

- ***Support for OPG regulatory processes related to performance-based rates****:* LEI was engaged by OPG to support OPG regulatory processes related to performance-based rates during a consultative process initiated by the OEB. LEI prepared a discussion paper on incentive regulation mechanisms ("IRM") currently in place in Ontario for electricity and natural gas distribution utilities and presented it at a technical workshop at the OEB. LEI staff, including Mr. Goulding, also made a presentation on the cost of capital and risk factors associated with OPG's regulated assets. [OEB Proceeding No. EB-2012-0340]
- ***Assistance in setting performance standards for NSPI:*** LEI was engaged by the Nova Scotia Utility and Regulatory Board (NS UARB) to assist in setting performance standards for Nova Scotia Power Inc. ("NSPI") in respect of reliability, response to adverse weather conditions, and customer service for Nova Scotia. Mr. Goulding and Mr. Pinjani served as testifying experts. [Proceeding No. 2016 NSUARB 193]
- ***Expert to the Inquiry for the Commission of Inquiry Respecting the Muskrat Falls Project***: LEI was engaged by the Commission of Inquiry Respecting the Muskrat Falls Project to serve as an expert to the Inquiry. LEI prepared a report addressing the following topics: a comparison of Newfoundland and Labrador's electricity regulation system relative to other jurisdictions; assessing the system's ability to deal with challenges stemming from interconnection, including energy marketing; exploring the province's energy policy;

recommending changes to the province's electricity pricing model; and assessing the potential role for renewable energy generation expansion. Mr. Goulding served as the testifying expert. [LEI Report at Exhibit P-04457]

- ***Assistance in a distribution facility owner's participation in the AUC proceeding to establish PBR parameters:*** LEI was engaged by a distribution facility owner to provide expert evidence and assist in its participation in the Alberta Utilities Commission ("AUC") proceeding to establish parameters for the third performance based ratemaking ("PBR") term in the province. LEI provided recommendations related to the timing of PBR rate adjustments, merits of the price cap versus revenue-per-customer cap approaches, I factor, X factor, capital funding provisions, earnings sharing mechanisms, and quantifying and tracking efficiencies. LEI based its recommendations on industry best practices as well as analysis of Alberta-specific data. [AUC Proceeding 27388]
- ***Regulatory support for Black Swan Energy in its response to the application of NGTL to the CER:*** LEI was retained to provide regulatory support for Black Swan Energy in its response to the application of NOVA Gas Transmission Limited ("NGTL") to the Canada Energy Regulator ("CER"). LEI reviewed the application and assisted in trial preparation. LEI prepared an expert report to form the basis of Black Swan's intervenor evidence, and responded to information requests ("IRs"). Mr. Goulding served as the testifying expert. [CER Proceeding No. RH-001-2019]
- ***Regulatory assistance to ENMAX on various PBR related issues:*** LEI supported an electricity distribution company (ENMAX Power Corporation) in Alberta, Canada, in its application to restructure rates to move from cost-of-service to performance-based approach. LEI prepared a filing for the company's regulator proposing a formula-based tariff-setting scheme, based on LEI-developed formula for periodic adjustments to an average tariff metric based on an inflation factor, efficiency factor, the impact of capital investments, operational performance relative to defined metrics; and defined mechanisms for additional adjustments based on force majeure and financial performance outside a defined range. LEI team members provided strategic advice to the CEO and other senior managers on presenting the firm's proposal to the regulator and stakeholders; and provided expert testimony in support of the firm's filing to its regulator. Mr. Goulding served as the testifying expert. [AUC Application No. 1550487]
- ***Extensive analysis associated with financing/refinancing activities***: LEI has served as an independent market expert during the financing or refinancing of numerous zero-emitting resources in North America and other global jurisdictions. For instance, LEI has provided the independent market advisor report associated with refinancing of multiple hydro, solar, and wind assets owned by companies other than OPG across North America, as well as in Latin America and the Middle East.