Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2024-0063

A generic proceeding commenced by the Ontario Energy Board on its own motion to consider the cost of capital parameters and deemed capital structure to be used to set rates

BEFORE: **Michael Janigan**
Presiding Commissioner

Lynne Anderson
Chief Commissioner

Pankaj Sardana
Commissioner

March 27, 2025

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1 OVERVIEW AND SUMMARY

This is a Decision and Order of the Ontario Energy Board (OEB) regarding a generic proceeding initiated on its own motion to consider the cost of capital and other matters for electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators. The OEB has revised the methodology for determining the values of the cost of capital parameters to be used to set rates and has approved updated values to be used for 2025 cost-based rates applications, effective January 1, 2025. The OEB has left the methodology for determining capital structure unchanged, as well as the capital structure values themselves.

Other matters were also addressed in this proceeding, with 22 issues in total.

While the reasons are set out later in this Decision, the key findings of the OEB are summarized as follows:

- The Fair Return Standard (FRS) has been met since 2009, using the 2009 Cost of Capital Framework.
- Cost of capital parameters have been set on a final basis, effective January 1, 2025:
    - Return on equity (ROE) of 9.00% (including 25 basis points for flotation costs) applicable to all electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators
    - Deemed long-term debt rate (DLTDR) of 4.51%
    - Deemed short-term debt rate (DSTDR) of 3.91%
- An annual ROE adjustment formula has been determined to adjust rates for 2026 and beyond for cost-based rate applications.
- No changes in capital structure have been made. The capital structure applicable to Enbridge Gas Inc., Ontario Power Generation Inc., and EPCOR Natural Gas LP South Bruce territory will be determined at the next cost-based rates application for each of these utilities.
- The new cost of capital parameters (i.e., ROE, DSTDR, and DLTDR) will be implemented at the utility's next rate rebasing application.
- The term of the new Cost of Capital Framework is five years, such that the cost of capital policy shall be reviewed again in five years.
- Q2 2025 prescribed interest rates will be effective April 1, 2025 on a final basis:
    - The prescribed interest rate for deferral and variance accounts (DVAs) will be 3.16%
    - The prescribed interest rate for the construction work in progress (CWIP) account will be 4.23%

2 CONTEXT AND PROCESS

When the OEB reviews a cost-based rates application by a rate-regulated utility, many costs are included in that review. The cost of capital is one of those costs. In any given year, about 10-20% of Ontario's rate-regulated utilities apply for such a cost-based review.

The OEB publishes its approved cost of capital parameters annually on its website.

The OEB last reviewed its cost of capital methodology in 2009 culminating in its *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (2009 Report), dated December 11, 2009.[1] An OEB staff report (Staff Report) on the cost of capital policy was published on January 14, 2016.[2] OEB staff concluded in the Staff Report that the methodology adopted in late 2009 was working as intended.

On March 6, 2024, pursuant to sections 36, 78 and 78.1 of the *Ontario Energy Board Act, 1998* (OEB Act), the OEB issued a Notice of Hearing on its own motion to initiate a generic proceeding. This generic proceeding considered the methodology for determining the values of the cost of capital parameters and capital structure to be used to set rates for electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators. The OEB also considered whether its current approach to setting the cost of capital parameters and capital structures continues to remain appropriate and if not, what approach should be used. Other matters were also addressed in this proceeding, which included 22 issues in total.

In addition to the OEB's policy to review cost of capital parameters periodically, further impetus for this generic proceeding can be found in the Auditor General of Ontario's Value-for-Money Audit, published in November 2022, and in the OEB's 2023-2026 Business Plan and 2024-2027 Business Plan.

A number of parties participated, including utilities and ratepayer groups. Schedule A provides a list of parties to this proceeding.

Four expert witnesses participated in this proceeding and filed expert reports:

- London Economics International LLC (LEI) on behalf of OEB Staff

[1] EB-2009-0084.
[2] EB-2009-0084.

- Concentric Energy Advisors, Inc. (Concentric) on behalf of the Ontario Energy Association (OEA)[3]
- Nexus Economics LLC (Nexus) on behalf of the Electricity Distributors Association (EDA)
- Dr. Sean Cleary (Dr. Cleary) on behalf of the Industrial Gas Users Association (IGUA) and the Association of Major Power Consumers in Ontario (AMPCO)

As noted in Procedural Order No. 1, OEB staff's expert report served as a "straw-person" for all other parties (and their experts) to comment on or adduce evidence in response.[4]

All parties came to an agreement regarding a proposed Issues List after an Issues Conference was held on April 18, 2024. Three modifications made by the OEB were reflected in the approved Issues List. The April 22, 2024 approved Issues List can be found at Schedule B.

The key documents and procedural steps in this proceeding included the Issues Conference, expert reports, interrogatories, a Presentation Day, a six-day oral hearing over three weeks, written submissions, and written reply submissions.

The following schedules summarize and provide the following:

- Schedule C – the revised methodology for calculating the cost of capital
- Schedule D – the revised methodology to update the ROE
- Schedule E – the revised methodology to update the DLTDR
- Schedule F – the revised methodology to update the DSTDR
- Schedule G – the revised methodology to update the prescribed interest rates
- Schedule H – the Current Cost of Capital Framework

[3] The OEA is acting on behalf of the CLD+. The CLD+ comprises Alectra Utilities, Elexicon Energy, Enbridge Gas, Hydro One Networks, Hydro Ottawa, Ontario Power Generation, Toronto Hydro-Electric System, and Upper Canada Transmission 2.
[4] Procedural Order No. 1, March 28, 2024, p. 4.

3 DECISION ON THE ISSUES

3.1 General Factors

3.1.1 Current Cost of Capital Framework

Schedule H includes a detailed description of the OEB's 2009 Cost of Capital Framework. The OEB concurs with the Staff Report from 2016 which concluded that the 2009 Cost of Capital Framework worked as intended. Having reviewed the evidence in this proceeding, the OEB also concludes the 2009 Cost of Capital Framework has resulted in the FRS being met since 2009. This was a factor that was considered in the findings that follow in this Decision.

The FRS has three components, as accepted by the OEB in the 2009 Report. A fair or reasonable return on capital must meet all three of the following components:

1. Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
2. Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
3. Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[5]

The OEB confirms that it is establishing the new Cost of Capital Framework in this Decision in conformance with the FRS. In doing so, different methods and methodologies were considered.

3.1.2 Energy Transition and Other Risks (Issue 2 and Issue 3)

Expert Report Proposals

LEI stated that the term energy transition refers to a shift from an energy system that primarily relies on fossil fuel-based energy sources (e.g., natural gas, coal and oil) to net zero-emitting renewable energy sources (e.g., batteries, solar and wind power, and carbon capture and storage). LEI noted that the 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.

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[5] 2009 Report, p. 18.

LEI stated that the business and financial risk factors considered in recent equity thickness proceedings are sufficient and described such risk factors (including the energy transition).[6] LEI stated that in the forthcoming regulatory period it is not likely that energy transition will cause volatility of net cash flows or an increased risk of inability to attract capital or recover associated investments because of the use of various regulatory mechanisms. Dr. Cleary generally agreed with the risk factors listed by LEI.

Concentric agreed that business and financial risk factors should be considered (including energy transition).[7] Concentric stated that LEI's recommendation implies that changes in business/financial risks would be addressed solely with an adjustment of the equity thickness. However, in Concentric's view, both the equity thickness and the cost of capital need to be evaluated to meet the FRS. In Concentric's view, the risks resulting from the energy transition are not fully mitigated by regulatory mechanisms and are likely to continue to increase.

Nexus stated that distributors in Ontario are facing significant risks associated with the energy transition and other events. Nexus stated that as a result of these risk factors, capital spending is expected to increase markedly, triggered by significant load growth, grid hardening, and cyber-security investments. Nexus stated that these risk factors are difficult to quantify with any certainty, and, for this reason, it did not add any increment to account for them in its estimate of ROE. However, to the extent the OEB is faced with a range of proposed ROEs, the OEB should not limit itself to the lower end of the range, and thereby fail to account at all for energy transition risk.

Nexus identified a category of risk that, in its view, LEI ignores — strategic risk.[8] In Nexus' view, LEI failed to recognize the magnitude of the changes distributors are likely encountering now and in the coming years.

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[6] As listed by LEI, business risk factors include: 1) Energy transition risk; 2) Volumetric risk; 3) Operational risk; 4) Regulatory risk; 5) Policy risk. The assessment of financial risks has focused on the utility's ability to continue to attract debt and equity financing at reasonable terms. The evaluation of financial risk includes the assessment of key credit metrics and their potential impact on credit ratings.
[7] As listed by Concentric: Business risk factors include: energy transition, regulatory risks (encompassing regulatory lag, timely recovery of OpEx, fuel costs, and capital costs, volumetric risk, and others), and other business risks (including severe weather events, technology risks, and others). Financial risk factors encompass: solvency, liquidity, and ability to attract capital and raise debt.
[8] Nexus stated that strategic risk is the risk that distributors are subjected to, as they face increasing uncertainty regarding the direction of the industry and the significant investments that they will be required to make, despite the uncertain future.

Regulatory and Rate-Setting Mechanisms

LEI stated that 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 available regulatory mechanisms. Dr. Cleary also noted that these regulatory mechanisms are among several factors that are considered by debt rating agencies in their business risk assessment of utilities. LEI recommended that 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 and should be retained. Dr. Cleary shared this perspective.

Concentric recommended that the assessment of regulatory and rate-setting mechanisms should be based not only on the consideration of such mechanisms on an absolute basis, but also based on a comparison of Ontario's regulated utilities to the proxy group of companies used to determine the cost of equity (i.e., authorized ROE and deemed capital structure).

Nexus stated that the regulatory and rate-setting mechanisms offered by a jurisdiction can influence the risk to which the utility is exposed. Nexus was unable to conclude that the regulatory environment offered in Ontario is significantly safer than its peer jurisdictions and suggested that the OEB should not approve a lower ROE for Ontario electricity distributors. Nexus also referenced a "systematic underearning" of Ontario electricity distributors.

Submissions

There was general consensus that the key risk factors that need to be considered when determining the cost of capital parameters and capital structure include business risks and financial risks.

With respect to energy transition risk, OEB staff submitted there was no evidence presented that the unfolding energy transition impacts either timing or recovery for regulated utilities, particularly in the forthcoming regulatory period (2025-2029).

OEB staff further recommended that any uncertainty from the energy transition can be addressed in utilities' respective cost-based rate applications or in applications by electricity distributors made under the OEB's *Non-Wires Solutions (NWS) Guidelines for Electricity Distributors*.[9] Pollution Probe generally agreed with OEB staff that to the

[9] EB-2024-0118, Non-Wires Solutions Guidelines for Electricity Distributors, March 28, 2024, p. 6.

extent that energy transition increased or decreased the need for capital investments, this is dealt with through the regular rate cases, rather than a generic consideration.

Several ratepayer groups submitted that there was no evidence at this time that energy transition is happening to any significant extent, nor that it would increase business risk for electricity utilities. Some also stated that risk might even decrease. CCC submitted that Ontario's electricity distributors and transmitters have the ability to recover all prudently incurred costs, therefore, demand growth and related capital spending would not increase the risk they face. Several ratepayer groups submitted that demand growth is an opportunity for electricity distributors and transmitters. VECC added that, if energy transition was to be considered as a separate risk category, then care needed to be taken to ensure that its impacts on risk were not double-counted. AMPCO/IGUA stated that there is a plethora of supportive regulatory mechanisms that the OEB has, and continues to put in place to support Ontario's utilities through the expected energy transition-related impacts on their businesses.

The EDA and the OEA submitted that no expert disputed that the energy transition will happen, but the issue is when it will happen. In the view of both the EDA and OEA the evidence in this proceeding is that new capital is required now, and this is introducing energy transition risk.

The EDA stated that to the extent the OEB is faced with a range of proposed ROEs, the OEB should not limit itself to the lower end of the range and thereby fail to account at all for energy transition risk. The OEA noted that Concentric had not made any explicit adjustments to its ROE or capital structure recommendations on the basis of the energy transition, as these effects were captured in the financial models used to analyze the cost of capital.

The EDA noted the point raised by certain intervenors that energy transition could be considered an opportunity for electricity utilities, with any risk mitigated by increases to the overall demand for electricity and therefore increases in revenues. The EDA commented that there was no logical connection between the prospect of increased revenues and a reduction in risk.[10] The OEA shared this view and argued that increased capital requirements from initiatives related to the energy transition will in turn place pressure on the utilities' credit worthiness.[11]

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[10] The EDA's reasons were that: 1) demand projections and associated revenues may never materialize, leaving Ontario utilities at risk of building assets that are ultimately under-utilized; 2) most of the EDA's customers are residential, and distribution fees do not vary with increased demand.
[11] The OEA stated that risks associated with regulatory lag, operational risk (including climate change risk and cyber security risk), capital spending, and cost recovery risk grow along with capital expenditure.

The OEA noted that the energy transition does not only affect electricity utilities, but also impacts natural gas utilities, as it poses a risk that assets used to serve existing and new Enbridge Gas customers will become stranded. In particular, the OEA noted that a significant risk to Enbridge Gas due to the energy transition is one of declining demand, while still being obligated to operate and maintain a safe and reliable natural gas distribution system.

CCC agreed that the potential for declining new customer connections, fuel switching away from natural gas and related stranded asset risk were all issues that operate to potentially increase the risk for Enbridge Gas. CCMBC stated that only gas utilities may face increased risk. VECC concluded that if the OEB decided to increase either ROE or change the capital structure to accommodate an assessment of energy transition risk for Enbridge Gas, it should lower the same for electricity distributors, transmitters, and OPG. VECC submitted that one risk cannot go up without the other going down.

CCC pointed to the very strong credit ratings for all electricity distributors and transmitters that reinforce the strong financial position these companies are currently in (and are expected to be in the future). CCC recognized that reductions to the approved ROE and/or equity thickness could impact future financial assessments, but the OEB should continue to monitor any changes that do occur.

It was unclear to VECC why, just like any other risk, the ROE methodologies adopted by the OEB did not already capture energy transition issues.

Regulatory and Rate-Setting Mechanisms

OEB staff agreed with LEI and Dr. Cleary that any regulatory mechanism that can significantly impact the stability of future cash flows must be considered part of regulatory risks. OEB staff concluded that the OEB’s regulatory and rate-setting mechanisms had moderately reduced utility risk since 2009 and its proposals on ROE and capital structure reflected that.

While the OEA acknowledged that certain regulatory mechanisms put in place since 2009 have helped to mitigate risk, it agreed with OEB staff that the effects on utilities’ overall risk profile had been “moderate”. However, the OEA cautioned that a moderate decrease in regulatory risk does not equate to a decrease in a utility’s business risk as a whole, noting that there were new risks incurred since 2009 (e.g., climate change risk and cybersecurity risk). The OEA noted that a key area of dispute between the parties related to the magnitude by which regulatory mechanisms have reduced regulatory risk.

CCC submitted that the OEA's view that the regulatory risk faced by Ontario's rate-regulated utilities is similar to the risks faced by Concentric's proxy group is not accurate.

CCC stated that regulatory policies since 2009 applicable to Ontario's distributors and transmitters reflect a substantial decrease to risk that should be considered when setting the ROE in the current proceeding. Pollution Probe echoed CCC, stating that this decrease is in part due to the increase in DVAs to mitigate risk and uncertainty. SEC stated that capital cost recovery mechanisms have improved since 2009 and this has lowered risk. Energy Probe also submitted that the OEB's rate-setting policies since 2006 had slightly reduced the risks for electricity distributors.

CCC and SEC noted that S&P Global and Fitch Ratings affirm the low-risk regulatory environment, with these rating agencies describing Ontario as one of its "most credit-supportive regulatory jurisdictions".

VECC submitted that the OEB should acknowledge the reduction in risk due to certain policy changes (e.g., the OEB changed residential rates for distribution in the electricity sector to be assessed on a fixed basis) and make the appropriate reduction in ROE or capital structure. CME stated that these policy changes either reduce uncertainty, increase flexibility, or provide compensation for changes in risks.

Findings

Energy Transition

There is an energy transition underway in this province and around the world. It has been defined as a shift from fossil fuels towards a sustainable, renewable energy future. It is expected to result in a greater demand for electricity. According to the Independent Electricity System Operator's (IESO) recent outlook,[12] electricity demand is forecast to increase 75% by 2050. Clearly this will have an impact on the energy sector.

Some parties in this proceeding argued this is an increased risk to the sector, other parties argued that this is an opportunity for utilities, in particular electricity utilities. The OEB concludes that both points are true. Electrification is expected to increase the demand for electricity and the rate bases of electricity utilities, allowing them to earn higher returns for their shareholders.

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[12] IESO 2025 Annual Planning Outlook updated October 16, 2024.

The OEB understands that growing equity can put downward pressure on the ROE (return divided by equity), but net income (the return) will also grow. A stable growing monopoly utility should be an attractive investment to both debt and equity investors. A rapid pace of change can challenge utilities to adapt, whether they are dealing with availability of resources to meet increasing demand, managing stranded assets, adopting innovation, or changing sales volumes. This could increase risk along with the opportunity, but the key question is, what is the pace of this change?

The OEB is setting a five-year new Cost of Capital Framework for cost of capital with this Decision, as described under Section 3.6 of this Decision. The OEB has concluded that while there will be effects of energy transition during the term of the new Cost of Capital Framework, the effects are too uncertain in the next five years to adjust the ROE or equity thickness either upwards or downwards. In five years, the pace of change is expected to be clearer and the OEB can consider this issue again at that time. While the OEB has made its determinations in this Decision aware of energy transition issues and its potential effects, no specific adjustments have been made to the cost of capital parameters or capital structure to address it. As also stated in Section 3.6 of this Decision, utilities can file evidence in individual rate hearings to support different approaches due to their specific circumstances.

Other Risks and Regulatory and Rate-Setting Mechanisms

Utilities have argued that in addition to energy transition, other risks are increasing such as cyber security, changes in sales volumes, extreme weather events, and changes in government policies. Some ratepayer groups argued that the risk for utilities is actually lower now than in 2009 when the cost of capital policy was last reviewed, and OEB staff submitted that “the OEB’s regulatory and rate-setting mechanisms have moderately reduced utility risk since 2009”.[13] The OEB finds that any increased risks have been at least mitigated by the OEB’s regulatory approach, which S&P Global has classified as “most credit supportive”.[14] Furthermore, in 2023 DBRS considered the regulatory regime in Ontario a key strength in its rating considerations and in 2024 DBRS called Ontario a “reasonable regulatory environment”.[15]

Coupled with its conclusion that there is no clear indication of increased risk caused by energy transition at this time, the OEB finds that the risk associated with the operations

[13] OEB Staff Submission, November 7, 2024, p. 5.
[14] S&P Global Ratings. North American Utility Regulatory Jurisdictions: Some Notable Developments. November 10, 2023.
[15] DBRS Morningstar. Press Release Rating Report: Hydro One Inc., November 20th, 2023 and November 1, 2024; Exhibit N-M2-10-SEC-41, Attachment 4, p. 59, August 22, 2024.

of electricity distributors and transmitters has not increased. In the Phase 1 Enbridge Gas proceeding (EB-2022-0200), the OEB determined that Enbridge Gas's equity thickness would increase to 38% in 2024 after a review of the utility's risk profile, as discussed further in Section 3.3 of this Decision. OPG is expected to file a major payment amounts application in 2025 in which its risk profile can be reviewed. Accordingly, no generic adjustments for either Enbridge Gas or OPG are being made in this proceeding to account for either increasing or decreasing risk.

Any suggestion from experts or parties that the OEB should review its broader regulatory mechanisms is not in scope of the issues in this proceeding.

The OEB recognizes the current evolving situation with respect to trade tariffs. There was no evidence and only one brief submission on this topic given it is a recent development, and therefore any risk related to this has not been factored into the new Cost of Capital Framework. As discussed in Section 3.6 of this Decision, the OEB will be monitoring market conditions and could initiate an earlier review of cost of capital if warranted.

3.1.3 Perspectives of Debt and Equity Investors (Issue 11)

Expert Report Proposals

The expert reports differed on their assessment of the OEB's current approach to the determination of debt and equity from the perspective of investors. LEI and Dr. Cleary both generally agreed that the OEB's existing cost of capital methodologies explicitly considered perspectives of debt and equity investors. LEI stated that the 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 was not aware of OEB-regulated entities facing notable issues in attracting equity and debt capital since 2009. LEI and Dr. Cleary also stated that this is reflected in the utility credit ratings and the regular assessments performed by the credit rating agencies.

In Concentrics's view, the application of a formula by the OEB is generally perceived as favourable by credit rating agencies and equity investors because the return is set in a transparent and predictable manner and provides for relatively more stable cash flows and earnings for Ontario's regulated utilities. However, Concentric outlined several challenges associated with the successful implementation of ROE formulas. These include historical relationships that shift over time, reliance on government bond yields that do not reflect market uncertainty and limitations imposed on other analytic factors and judgement by a formula.

Nexus maintained that the OEB's current approach to setting cost of capital parameters did not succeed in achieving the central importance of meeting the interests of equity investors and did not meet the FRS. In support of its conclusion, Nexus noted the failure of its sample of Ontario distributors to earn its authorized return on average between 2015 and 2022 coupled with a comparison of OEB-authorized returns with those of comparable jurisdictions.

Submissions

OEB staff agreed with Concentric's view that the perspectives of debt and equity investors in the utility sector are among the most relevant considerations in setting the cost of capital parameters and capital structure. These investors provide important feedback on the reasonableness of the authorized cost of capital and whether the financial integrity, capital attraction and comparable return standards are being met. OEB staff agreed with LEI and Dr. Cleary that the OEB's current approach to cost of capital determination (including the determination of deemed capital structure) sufficiently considered investor perspectives, i.e., the allowed cost was commensurate with the perceived risks associated with the sector and met the FRS.

The OEA stated that growth of capital spending to meet increasing demand (such as that anticipated due to the energy transition) will put additional pressure on electric distributors' financial results and the perception of risk by both equity investors and credit rating agencies. The OEA also noted that increasing demand for electricity transmission driven by customers and jurisdictional policy adds pressure for transmission utilities not only to attract capital, but also to compete for limited supply chain resources for project construction.

CME submitted that the perspectives of both debt and equity investors is valuable in setting the cost of capital parameters and that the OEB's current practice takes both perspectives into account and does not need to be altered. CCMBC agreed that the perspectives of debt and equity investors in the utility sector are relevant. However, CCMBC stated that the only investors in municipally owned utilities were the municipalities, and such municipalities do not have a choice of making other investments. CCMBC submitted that the perspectives of municipal investors were not similar to the perspectives of outside investors.

The OEA disagreed with CCMBC, noting that CCMBC's approach ignores that debt and equity investors, even if focused on investor-owned utilities, provide relevant information regarding the investment community's perspectives on investing in utility infrastructure, which are relevant to all Ontario utilities.

Pollution Probe stated that the further a proxy company was from an Ontario pure-play regulated utility, the less relevant the comparison and the perspectives of debt and equity investors related to those proxies. In reply, the OEA noted that there was ample evidence that the North American capital markets were integrated and that investor perspectives across North America were relevant.

VECC noted that there also appeared to be general agreement as to what the perspectives of debt and equity investors were and that these perspectives align with the FRS. VECC submitted that these perspectives can best be taken into account by using market data in the determination of the cost of capital parameters, along with consideration of the views of credit rating agencies/ investment agencies with respect to the relevant risk factors.

VECC disagreed with Nexus' claims that underearning Ontario electricity distributors "provide[s] clear evidence that the current Board cost of capital parameters as a whole are inconsistent with the FRS." VECC stated that failure to earn the authorized ROE does not indicate that the authorized ROE is too low relative to the FRS, as there could be a number of reasons for differences between the deemed and actual ROE results.

Findings

Under Issue 11, the OEB asked about the perspectives of debt and equity investors related to cost of capital parameters and capital structure. There is little debate that the perspectives of debt and equity investors in the utility sector are highly relevant to the setting of cost of capital parameters and capital structure. Both groups are critical to determining the appropriate balance of risk and return, as they influence the cost of capital and, by extension, the capital structure of regulated utilities, in the following manner.

Debt Investors' Perspective

Debt investors are primarily concerned with the stability and predictability of a utility's revenue stream, given the essential nature of utility services. They expect a fixed return, typically at a lower rate than equity investors, particularly if utilities in the sector are seen as financially stable and the regulatory environment is predictable. However, if perceived risk increases (e.g., due to regulatory uncertainty or changes in utilities' business model), debt investors will likely demand a higher rate of return. The proportion of debt in a utility's capital structure impacts its cost of capital. Higher levels of debt may reduce the cost of capital but will increase financial risk.

Equity Investors' Perspective

Equity investors are more exposed to market volatility and regulatory changes and typically require a higher return to compensate for the greater risk of investing in a utility as an equity investor (versus a debt investor), particularly given that equity returns are not guaranteed and are subject to fluctuations. Equity investors consider both market conditions (e.g., the risk-free rate and the equity risk premium) and the utility's unique risks (e.g., operational performance and regulatory risk). Accordingly, the return expected by equity investors is often higher than the cost of debt because of these additional risks. Equity investors likely favour a capital structure with a higher equity ratio, as it provides a cushion against financial distress and reduces the risk that creditors — who have priority claims over shareholders — will absorb a disproportionate share of the utility's cash flows through debt servicing. A higher equity ratio also helps to ensure that returns to shareholders are not overly diluted by interest obligations, preserving financial flexibility and stability. Nevertheless, equity investors also need to consider the optimal ROE that balances their expectations with the utility's ability to attract debt financing at competitive rates.

The OEB notes that it has been presented with the challenging task of setting the appropriate cost of capital parameters and capital structure for utilities that reflects a balance between the interests of both debt and equity investors. Setting the ROE too low could discourage equity investment, which may raise a utility's cost of capital by forcing it to rely more heavily on debt. Conversely, setting the ROE too high could lead to unnecessarily high rates for consumers and potentially increase regulatory scrutiny by requiring adjustments to mitigate concerns about excessive returns.

While Nexus correctly notes that some electricity distributors underachieve their allowed ROEs in any given year, this does not in itself indicate that the FRS is not being met. It is also true that some electricity distributors over-achieve their allowed ROEs. OEB staff's July 18, 2024[16] letter provided data on 2023 regulated and deemed ROEs, for electricity distributors, electricity transmitters, natural gas utilities, and OPG. It showed that just over half of electricity distributors earned below their deemed ROE. In contrast, all six electricity transmitters reported regulated ROEs above their deemed ROEs, as

[16] Revised OEB Staff Letter, July 18, 2024.

did EPCOR Natural Gas, while Enbridge Gas's regulated ROE was slightly below its deemed ROE, and OPG had not reported its 2023 results on the date of the letter.

The OEB finds that underachievement (or overachievement) can result from various factors unrelated to the adequacy of the OEB's 2009 Cost of Capital Framework, including company-specific operational decisions, equity infusions from shareholders, cost structures, size, and efficiency. The key point is that the OEB's regulatory framework provides all regulated utilities with the opportunity to earn a fair return, though actual earnings may vary due to factors within a utility's control or are related to risks reflected in the setting of the ROE. Crucially, there is no systemic evidence that the current approach to setting ROE prevents efficient utilities from earning a fair return over time. Additionally, some municipally owned electricity distributors may prioritize lower distribution rates for their customers alongside achieving a fair return. While the extent to which this influences actual returns is unclear, it remains a potential consideration in understanding earnings outcomes.

After reviewing the evidence, the OEB concludes that the perspectives of both debt and equity investors have been appropriately addressed. Limited changes are being proposed to the cost of capital parameters and capital structure, as discussed in the sections that follow. No changes to the current capital structure for Ontario's electricity distribution, transmission and natural gas utilities, as well as OPG, are warranted as part of this generic proceeding. As noted previously and again in Section 3.6 of this Decision, utilities can file evidence in individual rate hearings to support any changes due to their specific circumstances.

The OEB does not agree with the claim that the generally lower deemed ROE and equity ratios for Ontario utilities relative to their U.S. peers undermine the FRS. On the contrary, the evidence suggests that Ontario's utilities, including OPG, have consistently accessed capital on favourable terms to meet their capital and operational needs. The OEB finds that the current results of the existing Cost of Capital Framework shows an effective balance achieved between supporting utilities' financial requirements and ensuring the opportunity for fair returns to investors, within the current regulatory and financial environment. Additionally, the OEB is satisfied that the cost of capital parameters and capital structure are appropriately set to accommodate the increased capital demands that may arise from the ongoing energy transition.

3.1.4 Sources of Capital and Ownership Structure (Issue 1)

Expert Report Proposals

LEI stated that the OEB's existing methodology implicitly accounts for differences in sources of funding when approving rate applications. LEI recommended 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 and should continue to use a systematic and empirical approach. LEI believed the status quo is consistent with the FRS and Canadian Supreme Court judgements. LEI also noted the statement in the 2009 Report that the OEB saw no compelling reason to adopt different methods of determining the cost of capital based on ownership.

In Concentric's view, it is consistent with both financial theory and regulatory practice to determine the cost of capital based on the use of funds and not the source of funds when determining just and reasonable rates. Concentric stated that if the OEB was to determine that the source of funds was determinative, the OEB would be required to distinguish between the cost of equity from different investors, and the sources of potential investment were numerous.

Dr. Cleary noted that the existing OEB policies should be maintained regarding sources of financing and of not considering ownership structure in determining cost of capital parameters. Dr. Cleary stated that the OEB's current practice of using actual debt rates in most cases considers the impacts of different funding sources, as noted by LEI, but the DLTDR can be used as an estimate or a ceiling (if the actual rate is higher than DLTDR).

Submissions

OEB staff submitted that the approach to setting the cost of capital parameters and capital structure should not depend on a utility's ownership and the source of funds. OEB staff noted that its view is consistent with the views expressed by LEI and other experts, and with the 2009 Report.

The OEA stated that consistent with longstanding OEB policy and the FRS, the approach to determining the authorized ROE or capital structure should not differentiate by ownership type. The OEA submitted that the administrative burden of distinguishing between ownership types would be immense. The OEA submitted that the capital structure should be determined on the basis of the use of funds, not the source of funds.

The EDA stated that the FRS focuses on the generic investor, without regard to the specific identity of the investor. The EDA further emphasized that the purpose of the exercise is not to determine whether the ROE should differ for a municipally owned utility versus a privately owned utility, and stated that the cost of capital depends on the use of funds, not the source of the funds.

AMPCO/IGUA stated that until tax laws change, it is “a complete fabrication” to suggest that Ontario municipally owned electricity distribution utilities must compete for capital in North American capital markets. AMPCO/IGUA stated that they have not done so, and simply cannot, as a matter of tax law and resulting affordability, do so.

CME submitted that the OEB’s current approach sufficiently considers the source of capital and therefore no change was required from the status quo, which does not consider ownership.

CCMBC argued that municipally owned utilities in Ontario are not investor owned. CCMBC submitted that the FRS that was established for investor owned utilities should not apply to them. Similarly, Energy Probe submitted that comparable investments would include utilities which have similar ownership structure and similar types of investors.

CCMBC and Energy Probe submitted that the approach to setting cost of capital parameters and capital structure should differ depending on the source of funds and ownership (i.e., source does matter). They suggested that government owned utilities in Ontario are “protected” from financial hardship. CCMBC stated that privately owned utilities do not have the same level of protection.

Energy Probe submitted that Ontario municipalities do not have a choice of investing in the stock market or their own distribution utility. Energy Probe noted that there are municipally owned utilities in the U.S. similar to the municipally owned electricity distributors in Ontario. Energy Probe submitted that it would have been possible to compare municipally owned utilities in the U.S. with municipally owned utilities in Ontario by benchmarking, but the experts chose not to do that. Energy Probe believed that this omission is a major deficiency of the evidence in this proceeding.

Findings

Whether a utility finances its operations through capital markets, municipal debt, or government lending, the fundamental risk associated with the utility’s activities (such as the regulatory environment, business model, and market risk) remains the same. The

ROE metric, of course, is at the heart of this issue, as it reflects the risk of the underlying assets and the returns required by investors to compensate for that risk. All the experts in this proceeding were generally in agreement that the approach to setting the cost of capital parameters and capital structure should not depend on a utility's ownership and the source of funds, but rather on the risks related to the business activities of utilities and their exposure to overall market movements.[17]

Additionally, the OEB has historically maintained an approach where the authorized ROE and capital structure are determined based on the risk profile of utilities and the capital needs of utilities, rather than on the ownership structure or the source of funds. The OEB is maintaining this stable approach.

Furthermore, from a regulatory perspective, it is critical to ensure that ratepayers are not unfairly burdened based on the utility's ownership structure or financing arrangements. Allowing different cost of capital treatments based on these factors could create inconsistencies in regulatory outcomes, where utilities with certain ownership structures or access to specific funding sources may have an advantage in securing lower-cost financing. While lower financing costs can benefit customers, selectively applying different treatments could lead to unintended disparities in how rates are set across utilities. This, in turn, could undermine the regulatory principle of fairness and consistency in determining just and reasonable rates.

Given these considerations, the OEB is firmly of the view that the cost of capital should be determined based on the use of funds and the risk profiles of utilities, rather than their ownership type or capital source. The approach to setting the authorized ROE and capital structure, consistent with longstanding policy, allows for a fair, predictable, and transparent regulatory framework. Differentiating based on ownership and capital source would introduce unnecessary complexity without a clear financial justification and could create potential inequities in rate treatment.

By continuing to focus on the core principles of financial theory and regulatory consistency, the OEB can ensure that ratepayers and utilities are treated equitably, while maintaining the stability and sustainability of the energy sector in Ontario.

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[17] This is in line with conclusions set out in modern capital structure theory particularly the Modigliani-Miller theorem noted in the LEI Expert Report, June 21, 2024, Revised September 23, 2024, pp. 100, 101

3.1.5 Indigenous Issues (Issue 1, Issue 13, Issue 20, Issue 21)

Expert Report Proposals

LEI noted that the OEB regulates indigenous owned utilities (e.g., Attawapiskat Power Corporation), as well as other utilities with Indigenous stakeholders (e.g., utilities structured as partnerships between Indigenous communities and private companies).

Concentric, Nexus, and Dr. Cleary did not comment on this issue in their reports.

Submissions

Submissions were made by the Three Fires Group Inc. and Minogi Corp. (TFG/Minogi), as well as the Caldwell First Nation (CFN) and Mississaugas of the Credit First Nation (CFN/MCFN).

Three proposals were made by TFG/Minogi, which CFN/MCFN endorsed, specifically requests for:

1. A risk premium for single-asset transmitters to be applied, in cases of Indigenous equity participation – this is discussed further in Section 3.3 of this Decision
2. The weighted average cost of capital (WACC) to be applied to CWIP balances for large, multi-year projects and investments – this is discussed further in Section 3.7 of this Decision
3. “Concurrent cost recovery” (CCR) to be applied for large, multi-year projects, i.e., a mechanism to allow for recovery during construction, before the project is in service – this is discussed further in Section 3.7 of this Decision

CFN/MCFN stated that their Aboriginal and treaty rights, land use, cultural heritage, and other rights and interests will be affected by the outcomes and policies adopted by the OEB as part of this proceeding.

CFN/MCFN’s submission was generally that:

a) The expert reports have entirely overlooked engagement with First Nations.
b) Assuming that the status quo of the OEB’s Cost of Capital Framework and policies is neutral for all entities is misleading, as First Nations face distinct barriers and impacts when accessing capital that are not accounted for under the status quo, nor considered as part of this proceeding.
c) Advancing reconciliation in this proceeding and Ontario’s energy landscape more

broadly requires engaging First Nations.

d) The specific and unique interests of First Nations related to the impacts of the OEB's cost of capital methodologies and related policies should be addressed within this proceeding, rather than deferred to a separate proceeding or engagement process.

TFG/Minogi's submission was generally that:

a) TFG/Minogi have demonstrated that the OEB's previous proceedings relating to the cost of capital have failed to account for the rights and entitlements of Indigenous people.
b) The current proceeding runs a high risk of repeating these errors and omissions of the past, most notably due to the silence of the four expert reports in this proceeding on Indigenous issues.
c) At least two of the four expert reports expressly adopt a bias in favour of the status quo.
d) The current omissions and biases are inconsistent with Canada's and Ontario's rapidly advancing recognition regarding supporting Indigenous economic opportunity.

TFG/Minogi stated that Indigenous groups and/or First Nations are increasingly becoming participants in Ontario's regulated utilities through partial equity ownership of individual regulated assets.[18] TFG/Minogi also made the following statements:[19]

- The cost of capital can present unique challenges for First Nations interested in more active participation in Ontario's energy sector.
- It strongly believes that these perspectives have historically been disadvantaged or excluded from Ontario's most important policy conversations.

TFG/Minogi stated that the duty to consult will arise where a potential or recognized Aboriginal or treaty right may be negatively impacted by a decision. TFG/Minogi suggested that the duty to consult had been triggered in this proceeding.

OEB staff responded to these intervenors' concerns as follows:

- OEB staff did not agree that the duty to consult had been triggered. OEB staff noted that TFG/Minogi and CFN/MCFN have not pointed to any particular

[18] N-M1-12-TFG/Minogi-1, August 22, 2024.
[19] TFG/Minogi Letter, August 16, 2024.

Aboriginal or treaty right that is engaged in this generic cost of capital proceeding, let alone how such a right might be negatively impacted. OEB staff stated that although the duty to consult is not at issue, there was consultation in this case with persons that had a substantial interest, including Indigenous communities, and the process was open and fair.

- In OEB staff's view, TFG/Minogi's and CFN/MCFN's criticism of the four experts was unfounded. OEB staff submitted that it was not reasonable to expect the experts to have engaged directly with Indigenous groups in the preparation of their reports.
- OEB staff submitted that what the OEB can do in this proceeding is, firstly, to ensure the generic cost of capital parameters meet the FRS, and secondly, to reiterate that if a utility believes it faces unique risks or challenges – including any in relation to Indigenous equity participation – then it can make its case for a more bespoke approach.

TFG/Minogi stated that the issues and the challenges that First Nations face take on increasing importance now, given the large volume of infrastructure projects that are already being undertaken as part of the energy transition.

TFG/Minogi stated that the implications of failing to address the distinct interests and circumstances of Indigenous peoples in this generic proceeding are stark. TFG/Minogi stated that it would create an ongoing necessity for Indigenous peoples to intervene in individual proceedings and to argue for alterations to the new default framework in every subsequent process, rather than have their interests and circumstances addressed at the outset.

The OEB permitted an additional submission by TFG/Minogi and CFN/MCFN to respond to OEB staff's submission with respect to the duty to consult and the Aboriginal or Treaty rights that could be impacted by this proceeding.

In its additional submission, TFG/Minogi stated that in summary, this proceeding will have a direct and meaningful impact on the future establishment and operation of energy infrastructure in Ontario, and particularly on the construction of significant new projects. This will necessarily produce potentially adverse consequences for the traditional territories where proposed projects are located, and thereby on the Aboriginal and Treaty rights of First Nations, in terms of their ability to use the land and resources in question.

For electricity distribution, the EDA suggested that discussions regarding Indigenous participation should be dealt with on a distributor-by-distributor basis. CCC submitted that the proposals by TFG/Minogi and CFN/MCFN should not be dealt with on a generic basis, applicable to all rate-regulated infrastructure projects. Pollution Probe stated that there could be a mechanism available for specific proposals to be brought before the OEB, in cases where adjustments are appropriate. Pollution Probe stated that Indigenous/ utility partnerships are not homogeneous and it would be difficult for the OEB to develop a special set of rules that would properly apply across the board.

Findings

TFG/Minogi and CFN/MCFN raised concerns regarding the duty to consult and Indigenous access to capital for energy investments. The OEB recognizes that Indigenous peoples may face unique challenges in financing infrastructure in their communities. However, the OEB agrees with the submission of OEB staff that the process of review and determination of cost of capital parameters does not give rise to the duty to consult in this proceeding. While regulatory arrangements to facilitate financial and ownership participation by Indigenous peoples may help to support the recognition of Indigenous rights and interests in the planning, construction and operation of facilities, such participation is not the only means of ensuring these rights and interests are observed.

The OEB's established approach to setting cost of capital parameters, and the approach that is being set in this proceeding, is based on the *use* of funds rather than their *source*, ensuring consistency and fairness across all regulated entities. The perceived potential inability for these parameters to meet the desired goals of Indigenous peoples cannot be realistically addressed and possibly remedied in a generic proceeding. In the OEB’s view, the appropriate means of addressing Indigenous concerns is not through adjustments to the generic cost of capital framework but rather through the use of other regulatory or policy mechanisms.

As noted by OEB staff, the OEB has previously considered alternative cost recovery mechanisms for specific circumstances. The OEB’s 2010 *Report on the Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario* (Infrastructure Investment Report) identified such mechanisms.[20] A more detailed discussion of these alternative mechanisms, in particular their relevance to CWIP and CCR, is provided later in Section 3.7 of this Decision. Furthermore, Section 3.3 of this Decision discusses the risk premium for single-asset transmitters.

[20] *Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, January 15, 2010 (EB-2009-0152).

In summary, the OEB finds that, in setting cost of capital parameters, it is the use of funds, not their source, that is determinative. This principle is consistent with established financial theory and aligns with the expert evidence presented in this proceeding. This regulatory approach applies uniformly across all utilities, regardless of ownership structure or the specific financial arrangements of any particular entity.

3.2 Return on Equity

3.2.1 Base Return on Equity (Issue 10)

Expert Report Proposals

LEI recommended using the Capital Asset Pricing Model (CAPM) to estimate ROE. LEI noted that CAPM is one of the most commonly used valuation methods. Using CAPM, LEI calculated a base ROE of 8.95%.

Concentric found that the OEB's ROE formula currently is not producing an authorized ROE that meets the FRS. Concentric recommended that the OEB re-set the authorized ROE to 10.0% based on the results of the Discounted Cash Flow (DCF), CAPM and Risk Premium models, with each method weighted equally.

Concentric noted LEI's conclusion that the OEB formula has met the FRS since it was last revised by the OEB in December 2009. Concentric mostly agreed with LEI that the Ontario formula has produced returns that are generally consistent with those authorized for other Canadian electric and gas utilities in most years since 2009, with the exception of the period during the COVID pandemic. However, Concentric stated that the OEB's formula return is substantially lower than the average authorized ROEs for comparable risk U.S. electric and gas utilities and therefore, in Concentric's view, is not sufficient to meet the FRS.

Concentric requested that should OPG bring forward a proposal and evidence in its next payment amounts application regarding whether and what amount of additional risk premium should be applied as part of its authorized ROE, the OEB consider that proposal at its discretion as part of that proceeding.

Concentric disagreed with various aspects of LEI's analysis to set the base ROE. Concentric stated that it is very important that the OEB periodically review the formula return because the cost of equity depends on factors other than government bond yields and utility credit spreads.

Nexus stated that the ROEs set by the OEB and proposed by LEI are nowhere near the return available from the application of invested capital to other enterprises of like risk. In Nexus' view, neither meets the legally required FRS. Nexus also stated these ROEs are likely, now and over time, to result in a situation where Ontario utilities are unable to attract capital on reasonable terms.

Nexus' approach involved applying multiple methodologies (i.e., CAPM, DCF, and Risk Premium) to arrive at its ROE recommendation, with various weights to each method. Nexus recommended an ROE of 11.08%.

To ensure that the results were truly comparable, the ROEs were adjusted by Nexus for the equity thickness of the firms in each jurisdiction because the equity thickness in the deemed capital structure in Ontario is different from that of the peer jurisdictions.

In its report, Nexus raised several concerns with LEI's calculations. It also emphasized that capital relevant to Ontario's electricity service providers ultimately originates from a single, integrated North American capital market. Additionally, Nexus acknowledged that while all financial models are simplifications of reality and inherently imperfect, they remain useful analytical tools despite their limitations.

Dr. Cleary recommended maintaining the existing formula methodology, with certain modifications. Dr. Cleary agreed with LEI that it made sense for the OEB to update the base ROE from the 9.75% established in 2009, to a base ROE that reflects current capital market conditions. In Dr. Cleary's view, this base ROE should be set at 7.05%. Dr. Cleary disagreed with the use of forecast yields, recommending the use of actual prevailing yields.

Dr. Cleary stated that U.S. utilities are not reasonable comparators for Canadian utilities because they have significantly higher business risk – partly due to their holding company structure and business holdings, partly due to operating in the U.S. and not in Canada, and partly due to the nature of their operations which entail more risk.

Dr. Cleary stated that the allowed ROEs in Canada have not declined in line with reductions in government and utility bond yields and hence have provided Ontario (and other Canadian and U.S.) utilities "excess compensation" in terms of allowed ROEs relative to their actual market-determined cost of equity.

To generate a base ROE of 7.05%, Dr. Cleary weighed all three of his allowed ROE estimates equally (i.e., CAPM, DCF, and Bond Yield plus Risk Premium model

(BYPRP) methods) because all three methods are used in practice and provide different perspectives.

Dr. Cleary stated that this estimate is reasonable when compared to expected long-term overall stock market returns in the 4-9% range and a long-term expected market return of 7.5% (without any flotation charges added), when the low-risk nature of regulated utilities is considered.

LEI's recommended ROE did not include an "adder" for flotation costs. The other three experts included a 50 basis point adder.

Submissions

Overview of Recommended Base ROEs

The two utility groups (the OEA and EDA) supported higher base ROEs, the ratepayer groups supported lower base ROEs, and OEB staff supported a middle ground approach.

OEB staff recommended a 2025 base ROE range of 8.79% to 9.32% (with no flotation cost adder) which, in OEB staff's view, meets all three prongs of the FRS.[21] OEB staff was of the view that the generic ROE should apply to all utilities. OEB staff stated that differences in risk between different types of utilities are already accounted for in the approved equity ratios.

OEB staff argued that: (1) The recommended ROE is in line with the status quo, which has worked well; (2) The recommended ROE is in line with what other Canadian energy regulators have approved; and (3) The utility experts' ROE recommendations are too high, and the ratepayer expert's recommendation is too low.

With respect to its "approaches to triangulation", OEB staff stated that a similar approach was used by the OEB in the 2009 Report. In the 2009 consultation that led to the 2009 Report, the five experts applied various methodologies. The OEB did not make a determination on which model was best. To the contrary, it explained: "Although the Board maintains its view that each of the tests has empirical strengths and weaknesses, the diversity of approaches tabled and discussed in the consultation was helpful. As a

[21] In its triangulation calculations, OEB staff relied on the ROE values originally recommended in the four expert reports and not based on more recent data to September 2024 (as provided in oral hearing undertakings).

result, the Board has given each test a weight in the process to establish the initial [Equity Risk Premium] (ERP) to be embedded in the Board's formula."

In this proceeding, the EDA concluded that its expert Nexus' proposed ROE of 11.08% (or an ROE within the range of 10.36% to 11.81%) meets the FRS. The EDA stated that the clustering of certain results from Nexus, LEI, and Concentric, despite methodological differences, supported the reasonableness of Nexus' approach and output.

The OEA supported its expert Concentric's proposal to adopt a multiple model approach to the determination of ROE, leading to a recommended base ROE of 10.0%.

AMPCO/IGUA endorsed a base ROE for Ontario's utilities of 6.55% (if effective June 30) or 6.45% (if effective September 30). While AMPCO/IGUA supported their expert Dr. Cleary's recommended 6.45% base ROE, AMPCO/IGUA stated that re-setting the base ROE to 7.0% (about the middle of the range of reasonableness defined by Dr. Cleary's work) would be a reasonable exercise of the OEB's discretion, pending the next cost of capital review.

In its reply submission, AMPCO/IGUA submitted that in respect of a base ROE for Ontario's regulated distributors (including Enbridge Gas) and electricity transmitters, the following base ROEs would be appropriate and within the range of reasonableness, as proposed by:

- CCC of 7.1%
- SEC of 7.58%
- VECC of 7.73%

AMPCO/IGUA stated that this was premised on market expectations that regulated distribution utilities are considered to be less risky than the average company and should generate returns no higher than the average expected market return, which Dr. Cleary derived to be approximately 7.5%. AMPCO/IGUA suggested exercising "common sense", stating that "overall, we advocate for a healthy dose of common sense in the exercise of this Board's discretion to determine an appropriate ROE, and deem an appropriate capital structure, for the purposes of determining a cost of capital to include in setting just and reasonable regulated Ontario energy utility rate."

Pollution Probe submitted that Dr. Cleary's base ROE of 7.05% and LEI's recommended base ROE of 8.95% represented a reasonable range for the OEB to consider and would help mitigate some of the excess returns currently provided.

CCC submitted that the base ROE for Ontario's electricity distributors and transmitters should be set at 7.1%, using Dr. Cleary's BYPRP estimate. CCC submitted that the OEB should fundamentally change its approach to establishing the base ROE, specifically transitioning away from a proxy group-based approach. SEC stated that there was a compelling argument for the OEB to reject all proxy groups and Dr. Cleary's BYPRP approach was the only model proposed by any expert that did not rely on proxy groups.

CCC also submitted that the ROE and capital structure for Enbridge Gas and OPG should be established separately from electricity distributors and transmitters and this should occur at each of Enbridge Gas's and OPG's next rebasing applications. SEC and VECC also recommended that the ROE and capital structure for OPG should be determined in its next payment amounts proceeding.

CCC submitted that if the OEB is concerned about the pace of the change, an alternative is to reduce the ROE in steps, setting the 2025 base ROE at 7.87%,[22] noting that further reductions may be needed in future cost of capital proceedings. CCC stated that the OEB could monitor whether this reduction to the allowed ROE has any negative implications, with the plan to continue to reduce the ROE further at the next generic cost of capital review. CCC submitted that if the OEB moves first and makes a meaningful reduction to the ROE applicable to Ontario's distributors and transmitters, regulators in other jurisdictions will follow suit (just as they have with respect to performance-based regulation).

In CCC's view, it is not appropriate to continue to set a single average ROE for all of Ontario's rate-regulated utilities and use the equity thickness as the lever to reflect risk differences between sectors as the OEB has done historically. CCC submitted that the ROE and the equity thickness are directly related and should be established by the OEB at the same time (as both must be considered in the determination of whether the FRS is met).

SEC proposed that the OEB set a generic ROE applicable to all utilities, except for OPG, and that the base ROE should be set at 7.58%. CME submitted that SEC's proposal for a 7.58% ROE has significant merit. However, should the OEB determine

[22] CCC stated that the ROE could be reduced to the half-way point between the 2009 implied equity risk premium (550 basis points) and the implied equity risk premium of 397 basis points resulting from CCC's proposed 7.1% base ROE.

that a higher ROE is necessary, CME submitted that the OEB should make it no higher than the 8.95% recommended by LEI in its report.

VECC's recommended base ROE was 7.73%.

Fair Return Standard and Economic Rent

OEB staff noted that the general principles outlined in the 2009 Report were well accepted and none of the four experts (as well as OEB staff) in this proceeding appeared to take issue with them. However, OEB staff noted that one principle that was not expressly stated, but implicit in the 2009 Report, is that a return that exceeds what is required to meet FRS amounts to economic rent. Several ratepayer groups argued that the current allowed ROE amounts to economic rent.

OEB staff noted that the fact that the current policy has supported a healthy energy sector for 15 years was a strong indication that drastic changes are not required. OEB staff noted that while some risks facing the sector may have increased, others (such as regulatory risk) have decreased. CCC stated that the risk of Ontario's electricity distributors and transmitters has not increased since 2009 and, instead, has decreased since that time.

The EDA submitted that the deemed ROE in Ontario must be increased to meet the legally required FRS and that it would be an error of law for the OEB to not do so. The EDA and the OEA suggested that the OEB should not be persuaded by Dr. Cleary's outlier proposal of a base ROE of 7.05% and provided reasons in their submissions. The OEA also submitted that it defied reason that Dr. Cleary recognized the risk of a credit rating negative reaction (indeed possibly a significant retreat from the Ontario industry), but still recommended the use of a 7.05% base ROE. The OEA also stated that Dr. Cleary neglected to acknowledge that a negative impact or downgrade(s) to a company's credit rating will also result in additional ratepayer costs, as the downgraded company's access to and cost of funding is also negatively impacted as a result.

The OEA concluded that Dr. Cleary's recommendations clearly fail the FRS. The OEA noted that for investor-owned utilities, the adoption of Dr. Cleary's ROE recommendation would constrain the growth prospects of Ontario's utilities. The OEA stated that projected EPS growth rates would likely be reduced by equity analysts, meaning that Ontario utilities might need to pay higher dividends to continue attracting sufficient capital to maintain the status quo.

The OEA submitted that, as noted by Concentric, the existing methodology (i.e., the current OEB formula) has generally produced a ROE that is consistent with returns for electric and gas utilities elsewhere in Canada. However, the OEA stated that the ROE produced by the formula, is substantially lower than authorized returns for comparable risk electric and gas utilities in the U.S. The EDA submitted that the OEB should make its decision consistent with the approach outlined in the 2009 Report, departing from it only if there is evidence of a significant change in circumstance.

In its reply, the OEA stated that evolutionary change is necessary, building off the strong foundations created by the 2009 Report, to ensure that the FRS is met. The OEA noted that there is no need to start from scratch or do away with the general structure and a number of established principles that have served the Ontario energy industry and consumers for the last 15 years. However, the OEA noted that unprecedented levels of capital investment will be required across the entire energy sector to facilitate the energy transition, all while ensuring safe and reliable electric and natural gas service for the foreseeable future and setting a fair return is the lynchpin.

AMPCO/IGUA stated that evidence of “downward stickiness” in awarded ROEs indicated that awarded ROEs are poor measures of utility-relevant financial market conditions and may lead to excess compensation. AMPCO/IGUA stated that given the lower risk of regulated utilities relative to the market at large, it is axiomatic that the long term expected return on investment in regulated utilities should be lower than the long-term expected average returns from the market as a whole. AMPCO/IGUA stated that Dr. Cleary derived an expected average Canadian equity market return, concluding that 7.5% represents an appropriate point estimate.

The OEA stated that this argument was fundamentally flawed and the argument relied on Dr. Cleary’s own evidence that the expected average Canadian equity market return is 7.5%. The OEA stated that there was no evidence supporting this market return and Dr. Cleary’s supporting evidence shows that the average total return for the Canadian market from 1938-2023 was 10.97% and the median was 11.05%.

CCC stated that establishing the base ROE for Ontario’s electricity distributors and transmitters at 7.1% would set the ROE for these companies below the long-term expected average Canadian market return (i.e., 7.5%), which properly reflects that these firms are lower risk than the market on average.

APPrO submitted that the OEB should not depart from existing policies and methodologies for determining the values of the cost of capital parameters and deemed capital structure used to set utility rates. Pollution Probe echoed APPrO stating that the approach outlined in the 2009 Report remained valid and that the OEB should consider an evolutionary, rather than revolutionary approach should any changes be considered to cost of capital and related parameters.

CME stated that there are two areas of professional judgement which need to be exercised in any evaluation of the comparable investment standard, namely 1) Whether or not two entities are truly “like”; 2) Whether or not, based on the degree of similarity between the entities or the degree to which they are alike, the return generated by the OEB regulated entities are “comparable”. CME submitted that when benchmarked against entities that are actually comparable to the OEB’s regulated Ontario utilities, the current allowed ROE and capital structures were sufficient to meet the comparable investment standard.

There was general consensus that comparator companies do not need to be identical but should share similarities and “‘like” does not mean the “same”.

CCMBC submitted that there is no evidence that the current deemed cost of capital does not meet the FRS. CCMBC and Energy Probe stated that energy transition, climate change, and cybersecurity have not increased the business risk of Ontario utilities, nor have financing concerns, to justify a large increase in the deemed cost of capital.

SEC submitted that the arguments and recommendations from several parties, including the utility groups, APPrO, and OEB staff, would result in a cost of capital that does not meet the FRS. SEC stated that they rely on flawed expert evidence, unsound analysis, and recommended approaches to setting the most critical components of the cost of capital, the ROE and equity ratio. In SEC’s view the resulting ROE and equity ratio are too high, would unfairly burden ratepayers, and is neither just nor reasonable.

SEC stated that the FRS requires that “utilities must be allowed, over the long run, to earn their cost of capital, no more, no less.” The “fair return” must balance fairness to both utilities and their customers. SEC submitted that the evidence indicates that the current ROE is not working as intended, because it is too generous to utilities at the expense of customers.

Multiple Methodologies

In OEB staff’s view, it was neither necessary nor advisable for the OEB to pick one of the four expert recommendations in this case, or to make a finding on which methodology (e.g., CAPM, DCF or Risk Premium) or which inputs are superior. OEB staff's recommendation was that the OEB should triangulate between the expert proposals, a broadly similar approach used in the 2009 Report. OEB staff stated that there is no single correct answer to the question of what ROE is needed to meet the FRS, and no magic formula for deriving it. As the OEB noted in the 2009 Report, there is value in considering multiple expert perspectives (and multiple methodologies).

In its reply, the EDA stated that OEB staff proposes that the OEB address a complex situation "by throwing up its hands and simply averaging the ROE figures proposed by all the experts." The EDA submitted that to do so would be unsound and was not a solution proposed by any of the experts, nor would it yield a ROE that satisfies the mandatory FRS. The EDA submitted that the OEB should continue to not rely on any one ROE methodology to the exclusion of others. The EDA stated that because no one methodology is without limitation, Nexus took a weighted average of its CAPM, DCF, and Risk Premium results to generate a deemed ROE.

The OEA stated that no financial model can exactly pinpoint the "correct" ROE; rather, each test brings its own perspective and set of inputs that inform the appropriate estimate of the ROE. The OEA noted that although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent limitations and should not be relied upon individually without corroboration from other approaches. The OEA noted that all of the experts (except for LEI) used a multiple model approach to determining ROE and other Canadian utility regulators have also recognized the benefits of using multiple methodologies to determine a fair ROE.

The OEA stated that the OEB should resist OEB staff's approach to setting a base ROE, as OEB staff's averaging methodology lacks any analytical utility or critical assessment of the experts' varying approaches. Instead, the OEA recommended that the OEB should take a more detailed and analytical approach to the assessment of each expert's recommendation. The OEA was also concerned that if OEB staff's averaging approach was adopted by the OEB, it could incentivize extreme positions by parties in future cases to "game" the outcome. SEC made a similar point.

AMPCO/IGUA stated that there are a multitude of judgements and choices made along the various analytical paths taken, and each expert takes a number of paths, all indicating that there is no single, multiple decimal point number that is "the" right answer. VECC agreed with the views of some of the experts that the results of multiple methods should be considered by the OEB in determining the ROE.[23] VECC stated that

[23] VECC stated that no one financial model can pinpoint the "correct" ROE and in one way or another

judgement and common sense need to be applied when considering the reasonableness of both the input assumptions to each model and the reasonableness of the results.

CCC submitted that for the OEB to apply no judgement with respect to the model outputs of the various experts and to simply weight them equally in determining the final base ROE calls into question the purpose of this entire proceeding. CCC generally agreed with OEB staff's statement that there was no precise number that is the "correct" ROE and there was no "magic formula" for deriving it, but argued that the OEB would not land at a reasonable result by applying an average to all experts estimates when the estimates of Concentric, Nexus and LEI are higher than is necessary to meet the FRS.

SEC submitted that ideally multiple models should be used to forecast the ROE, considering the inherent difficulty in estimating an appropriate ROE. However, SEC strongly disagreed with OEB staff's triangulation approach, as in SEC's view, it undermined the purpose of the hearing process by uncritically averaging results. SEC stated that significant time and effort were invested in exposing fundamental flaws in the various expert approaches, and the OEB should make decisions on these issues, rather than avoiding them through averaging. SEC stated that furthermore, an averaging approach did not make sense in the context of this proceeding where each of the experts' proposed applications of the ROE differed.[24]

Non-Canadian Comparators

OEB staff stated that investors are willing to accept lower returns in Ontario because the risk is lower and U.S. utilities are not actually comparable in risk to Ontario utilities. OEB staff noted that none of the four experts looked at comparators outside Canada and the U.S., even though financial markets have become globally integrated. OEB staff suggested that it might be worthwhile broadening the scope of comparators the next time the OEB reviews the cost of capital, whether in a generic proceeding or a utility-specific application.

The EDA submitted that the OEB should continue to consider U.S. data and comparables. The OEA stated that the approach taken by all the experts to use U.S.

each of the three models is a simplification of reality and, as a result, each has its flaws. VECC also stated that on the other hand, each provides a different perspective that can inform the OEB's decision as to the ROE that will meet the FRS.

[24] LEI and Dr. Cleary proposed that the ROE be applicable to each utility segment (electricity distribution, transmission, natural gas utilities, and OPG). Concentric proposed that the ROE be applied to all but OPG. Nexus applied the ROE only to electricity distribution.

companies as proxies (except for Dr. Cleary) was consistent with the OEB's view in the 2009 Report and that of other Canadian regulators.

In AMPCO/IGUA's view, U.S. equity markets are not relevant in deriving a fair ROE for Canadian regulated utilities, given a fundamental feature of the Ontario utility context: the legislated municipal utility tax regime. AMPCO/IGUA noted that with the exception of Hydro One, Ontario's electric distribution utilities cannot practically accept significant amounts of equity from any third-party investors, Canadian, U.S., or otherwise. CCC agreed. Energy Probe noted that there are no external investors in municipally owned utilities in Ontario and that none are possible under the current tax laws.

AMPCO/IGUA argued that U.S. comparators and inputs should not be used, or at the very least caution must be exercised in placing significant weight on U.S. capital market considerations. CCC stated that the experts in this proceeding (other than Dr. Cleary) recommended that U.S. data play a prominent role in the establishment of the base ROE in both the current proceeding and the 2009 review, but this was not appropriate. CME stated that if the OEB chose to accept comparisons to entities that are outside of Canada, it should adjust any ROE results to account for the difference in risk between Ontario entities and those that operate outside of Canada. If the OEB determined that it was appropriate to compare Ontario utilities to U.S. utilities, CME submitted that the OEB should exercise "significant judgement" and adjust the ROE and/or the equity thickness downwards to achieve comparable returns between Ontario and U.S. utilities.

SEC acknowledged the need to use U.S. comparators due to the limited number of publicly traded Canadian utilities. However, it emphasized that cross-border differences must be carefully considered as U.S. utilities face distinct risks compared to their Canadian, particularly Ontario, counterparts. SEC stated that these differences are evident in market data, with both SEC and VECC noting that U.S. utility betas have historically been higher than Canadian utility betas. Pollution Probe stated that it is not sufficient or prudent to say that because financial markets in Canada and the U.S. are integrated in some manner that using U.S. holding companies as a proxy is correct.

In VECC's view it was reasonable to consider the inclusion of U.S. companies in the proxy groups, thereby creating a larger proxy group that will provide more robust results. However, VECC stated that if U.S. companies are included, then any additional differences in risk profiles created by their inclusion must be recognized when using the results of the subsequent ROE analysis to determine the appropriate cost of capital parameters for Ontario's regulated utilities. VECC stated that this can be done by: i) setting the ROE for Ontario's regulated utilities at a value less than that determined through the ROE analysis and/or ii) setting the equity thickness at a level less that of the companies in the peer group.

Home bias

CCC stated that LEI and Dr. Cleary addressed the existence of a home bias exhibited by Canadian investors. While accepting that there is an integrated Canadian-U.S. capital market, and that investors will examine both Canadian and U.S. companies to deploy their capital, SEC also agreed with the notion of a home bias. The EDA stated that there was no evidence of a home bias and the suggestion of its existence was just speculation.

Other ROE Matters

Both the EDA and the OEA noted that their respective experts (Nexus and Concentric) made no adjustment to their proposed ROEs to reflect any risk associated with the energy transition.

Several ratepayer groups noted that higher-than-required ROEs only exacerbate the existing utility bias toward capital expenditures, which creates barriers to a cost-effective energy transition.

Findings

The OEB affirms that in setting this important component of the determination of the cost of capital for regulated utilities it adopts the requirements of the FRS, as set out in the 2009 Report. These requirements mandate a regulatory return that meets the market expectations derived from the review of comparable investments, ensures the financial integrity of the subject utilities and allows for compliance with the capital attraction standard: the approved return must permit incremental capital to be attracted to the enterprise on reasonable terms and conditions. The FRS does not involve the balancing of interests between the utility and its customers but is singularly focused on ensuring that a utility is furnished with the necessary financing to carry out its responsibilities of service to its customers. However, the utility is allowed the opportunity to earn its cost of capital, no more and no less.[25]

The OEB is setting the deemed ROE at 9.00% for 2025, which consists of a base ROE of 8.75% plus 25 basis points for flotation costs. The OEB has reviewed the results of

[25] *Ontario (Energy Board) v. Ontario Power Generation Inc.*, [2015] 3 SCR 147.

the 2009 Cost of Capital Framework established in the 2009 Report over the past 15 years and concludes that it continues to satisfy the FRS. For 2025, an interim ROE of 9.25% was set, reflecting a base ROE of 8.75% plus 50 basis points for flotation costs. The OEB considered evidence suggesting this level is both too high and too low, as well as broader sectoral and FRS considerations. Based on this assessment, the OEB finds that a deemed ROE of 9.00% is appropriate. The OEB does not agree that the ROE is the vehicle to address differences in OEB regulated utilities. It will continue the practice of addressing material differences through the capital structure, as discussed in Section 3.3 of this Decision.

All of the methodologies used by the four experts are worth consideration. This includes CAPM, DCF, and Risk Premium.[26] Three of the experts provided various weighting to the results of different models to provide recommendations, and LEI relied solely upon CAPM. However, it is clear from the evidence and testimony that none of these methods is without weaknesses, and the experts disagreed about the different approaches. Matters of disagreement included the use of multiple models, selection of comparable companies, whether to adjust betas to account for the expected migration of betas towards the market mean (such as through the Blume adjustment[27]), whether to use U.S. data, the accuracy of forecasts by sell-side analysts, whether discounted cashflows should be single stage or multi-stage (as well as growth factors), and whether to consider approved ROEs in other jurisdictions (in the Risk Premium approaches). The OEB concludes that there is no one gold standard methodology that can be used.

The question left with the OEB is whether to average the methodologies with known weaknesses, as was done for the 2009 Report or, with the benefit of 15 years of experience with the 2009 Report and the consideration of the experts' evidence, assess the current ROE against the FRS. The OEB has chosen the latter approach.

Use of U.S. Based Utility Data in 2009 Report

The 2009 Report provided a departure from the content used to determine what constituted comparable investments from previous utility regulation in Ontario and in other Canadian provinces.[28] The 2009 Report found that utilities in the U.S. were indeed

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[26] Specifically, Dr. Cleary used a Bond Yield plus Risk Premium model.
[27] Nexus Expert Report, July 19, 2024, pp. 67 & 68 stated that the idea, developed by Marshall Blume, is that historical betas are biased estimates of the future because of reversion to the mean (of 1.00) in the time-series data.
[28] At Presentation Day the Concentric witness stated that "The Board was really a leader in 2009 when it recognized the value of including both Canadian and U.S. companies in the proxy group for purposes of establishing the cost of capital for utilities – Presentation Day Transcript September 5, 2024, p.35

comparable. This approach was then adopted by LEI, Nexus, and Concentric in varying degrees in the current proceeding. The outcome of this conclusion was that, given an appropriate analytic framework in which U.S. results should be used, the required parameters for cost of capital could be determined. The exercise of adopting this same approach in this proceeding contributes to the resulting recommendations by Nexus and Concentric that are considerably above current levels of ROE for Ontario regulated utilities.[29]

Financial integrity and the ability to raise capital are not impaired by the current cost of capital framework.

In the current proceeding, the OEB had the advantage of assessing the expert evidence along with the benefit of some fifteen years of experience with the current ROE within the 2009 Cost of Capital Framework. The 2009 Report was the result of a consultative process and not a hearing. In this proceeding there has been a full solicitation of evidence from OEB staff, regulated utilities, and ratepayer groups, and an extensive hearing with two rounds of submissions, prior to this Decision. It is understood that Canadian investors have an opportunity to earn a higher rate of return by acquiring equity in U.S. utilities and there is evidence that such investments are being made.[30] However, as Concentric notes, there is no assertion that the current ROE has impaired the financial integrity of Ontario regulated utilities, nor has there been any claim of failures to raise capital because of a lagging ROE or an unreasonable equity thickness.[31]

There are differences between Canadian and U.S. based utilities that must be recognized.

Substantial differences remain between Canadian, and U.S.-based utilities principally associated with risk, regulatory oversight and the engagement of U.S. regulated utilities in non-regulated business operations. As well, holding company structures and business holdings, operating in the U.S. and not in Canada, decrease comparability of regulatory results. The OEB concludes that the “home bias” of the Canadian investor to invest in Canadian utilities is a factor in giving less weight to U.S. comparators. These differences cannot be ignored in the OEB’s efforts to set parameters to meet the FRS.

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[29] LEI incorporated US utility data associated with CAPM and DCF estimates however did not arrive at estimates in the same range.
[30] Transcript Volume 4, pp 71-72.
[31] N-M2-10-CME-1, August 22,2024; Transcript Volume 4, p. 67-68.

The OEB acknowledges that its 2009 Report placed considerable weight on U.S.-based utility data in establishing reasonable expectations for returns that enable Ontario-based utilities to access capital. The expert reports filed by both the EDA (Nexus expert) and OEA (Concentric expert) in this proceeding have been responsive to the approach previously adopted by the OEB therein, notably the comparability of U.S. and Canadian utilities. While it may be relevant to consider U.S. utility ROE results, differences in structure and risk limit the ability to find truly comparable companies.

The conclusion that risk and investor reward are synchronized with U.S.-based utilities fails to account for developments in the OEB's regulatory framework which makes this conclusion more questionable. As CCC's submission notes:

> The changes to regulatory policy and the OEB's proactive approach to regulation de-risked utilities over the past 15 years. Distributors and transmitters have more protection than ever with respect to the recovery of costs during ratemaking terms (e.g., ability to recover forecast capital costs (Custom IR, ICM/ACM), ability to recover numerous categories of non-forecast costs or cost variances on forecast costs (DVA expansion), move to fixed charges for residential customers, etc.). Regulatory lag has also been significantly decreased (through changes to UTR policy, billing practices, etc.). Due to the OEB's favourable regulatory framework applicable to Ontario's distributors and transmitters, energy transition, climate and cyber security risks are not negatively impacting the risk profile of these companies.[32]

The integration of U.S. and Canadian utility markets and the potential lure of higher returns for investors is a factor to be considered in arriving at a final conclusion concerning the requisite ROE that must be provided to meet the FRS. However, the use of U.S. regulated utility data as equivalent to Canadian regulated utility data in any computation is questionable.

In 2009, financial markets were still emerging from the global financial crisis,[33] and investor sentiment remained cautious amid elevated risk premia, tight credit conditions,

[32] CCC Submission, November 7, 2024, p. 27.
[33] The economic conditions prevailing at the time of the 2009 Report differ considerably from those in existence at the time of this Decision that favoured regulatory efforts to ensure greater utility financial stability. The Canadian Energy Overview 2009 published by the National Energy Board concluded that the effect of the global recession of 2008 continued into 2009. The result was significant declines in demand, consumption and prices. There was a concurrent effect on financial markets and the ability of energy utilities to raise capital. The 2009 Report at page 7 noted that the difference between the cost of equity and the cost of long-term debt values determined by the OEB for the 2009 Cost of Service

and heightened market volatility. The broad policy response that followed, including accommodative monetary policy and financial sector stabilization measures, contributed to a significant reduction in systemic risk over time. Today, key indicators such as credit spreads, risk premia, and market volatility (as measured by the Volatility Index (VIX)) are markedly lower than during the 2007–2009 period, reflecting a more stable financial environment. Such a change in the financial landscape provides an opportunity for the OEB to re-assess the necessity of reliance on U.S. comparators when determining the FRS for Ontario utilities.

In 2009, the heavy reliance on U.S. comparators was, in part, a response to the heightened uncertainty and financial distress that made it difficult to draw reliable conclusions from Canadian market data alone. Current financial conditions demonstrate that Canadian and U.S. financial markets have been stable and well-functioning, and any potential short-term volatility is unpredictable. Therefore, there may be less justification for placing the same degree of reliance on U.S. comparators, without discarding appropriate U.S. comparators out of hand.

Energy transition will impact the utilities, and trade is creating uncertainty, but there is insufficient evidence to determine this impact within the term of this new Cost of Capital Framework.

As a number of parties have noted in this proceeding, energy transition will likely engage both demands on and opportunities for utilities, there is also a threat of economic turmoil arising from uncertainty concerning trade and market relations with the U.S. that may upset reliance on past and current performance of utilities. The OEB cannot find that there is evidentiary support for a significant change in the ROE with the five-year term of the new Cost of Capital Framework that would meet the FRS and the OEB's statutory objectives.

The current ROE does not generate economic rent from utility customers.

There is evidentiary support for a significant reduction to the current ROE advanced by Dr. Cleary. Both Dr. Cleary and LEI are instructive in providing reassurance that the regulator has discharged its responsibility to the utilities it regulates in meeting the FRS for their continued operation. The remaining question is whether the current ROE results in rates that are greater than required to meet that standard thereby generating economic rent from utility customers.

Applications was only 39 basis points versus a difference of 247 basis points in 2008. Today the difference is 449 basis points for 2025 rates (i.e., 4.49% = 9.00% ROE - 4.51% DLTDR).

Dr. Cleary's evidence endeavors to show a result that could meet that question in the affirmative. The effort produces a result that differs markedly from the other expert evidence by recommending a considerably lower estimate, with much of that difference attributable to his reluctance to accept the comparability of Canadian utilities with U.S. counterparts. His model thus engages a smaller number of comparators. As noted earlier, the OEB also has concerns about the ability to find true comparators from the U.S., which limits the number of comparators that might be definitively used.

However, a significant recommended change from the results of the current formula that has been meeting the FRS for utilities must be done with caution. The submissions of the EDA and the OEA set out potential concerns regarding an ROE reduction such as recommended in Dr. Cleary's proposal. The OEA pointed to the risk of negative credit rating impacts, which could increase the cost of debt financing for Ontario utilities and impose additional costs on ratepayers. The OEA also emphasized that setting an ROE at an insufficient level would constrain the growth prospects of Ontario utilities by reducing projected earnings per share growth, potentially forcing utilities to offer higher dividend payouts to attract equity investment. These outcomes would create financial pressures inconsistent with the requirement that utilities earn a fair return. Dr. Cleary himself acknowledged that a steep drop in ROE could create instability for regulated utilities from a credit rating standpoint.[34].

While the OEB does not accept that the challenge of energy transition requires an added cushion to the existing ROE at this time, it is reluctant to embark upon a sizable adjustment that may provide an obstacle to its success. The OEB remains cognizant of the necessity to allow a fair and stable return that is critical to maintaining investor confidence and securing the necessary funding to support safe and reliable electricity and natural gas service.

The OEB is of the view that maintaining the current formula without significant change does not constitute the levying of economic rent to ratepayers, contrary to the FRS. The OEB also agrees with the submission of OEB staff that the ROE should apply to all utilities and that the determination of the required equity thickness for regulated utilities meeting Ontario's energy needs should address differing risks and circumstances associated with capital acquisition, as noted in Section 3.3 of this Decision.

The OEB must weigh all expert evidence in the broader context of maintaining a stable and predictable regulatory environment. Given that the current 2009 Cost of Capital

[34] Transcript Volume 6, pp. 184 & 185: When asked by Commissioner Sardana whether a steep reduction in the allowed ROE "could have a credit rating chill in the sector," Dr. Cleary acknowledged, "It's possible"

Framework has continued to satisfy the FRS, the OEB is not persuaded that a significant reduction is warranted at this time.

Summary of ROE Findings

The OEB has determined that the approved ROE to be allowed OEB-regulated utilities, in accordance with Section 3.6 of this Decision, will be firmly connected to the actual experience of the current 2009 Cost of Capital Framework and an assessment of future challenges for those utilities. The support for this approach is based on the following:

1. OEB-regulated utilities have maintained their financial integrity and raised sufficient capital under the aegis of the existing Cost of Capital Framework.[35]

2. The OEB finds that there are significant concerns about the direct use of parameters associated with the cost of capital of U.S.-based regulated utilities. These concerns must temper their direct use as part of the approved computation of ROE of OEB regulated utilities because of differences in risk, regulatory oversight, and the engagement of U.S. regulated utilities in non-regulated business operations. The latter differences include the presence of holding company structures and business holdings and operating in the U.S. and not in Canada.[36]

3. As was set out earlier in this Decision the reality of the projected energy transition that is already taking place will likely have consequences for utility capital acquisition, and performance, including customer take-up and demand, although the extent of this is unclear over the next five years.

While the determination of the Cost of Capital is a forward-looking regulatory exercise, such determination must ensure that any projection of the required ROE has sufficient safeguards against divergence from expected results. In this Decision, a significant safeguard is the refusal of a sizable adjustment to the deemed ROE (either increase of decrease) until the impact of energy transition is better understood. In doing so, the OEB has given considerable weight to the observable impact of the 2009 Cost of Capital Framework to date as well as the uncertainty posed by ongoing and transformational energy developments.

This Decision thus provides continued adherence to the FRS, while adjusting the lens used to view continued utility performance as noted. The OEB finds that the current

[35] N-M2-10-CME-1, August 22,2024; Transcript Volume 4, p. 67-68. Transcript Vol 4. pp 67-69.
[36] Dr. Cleary Expert Report, July 22, 2024, p. 29.

2025 interim ROE of 8.75%, (excluding the 50 basis point adder for flotation costs) is appropriate to be applied going forward. Consideration of flotation costs is in the section that follows. It is also noted that this result does not significantly stray from the range of results put in place by other Canadian utility regulatory authorities.

3.2.2 Equity Transaction/Flotation Costs (Issue 10)

Expert Report Proposals

LEI's base ROE estimate did not include 50 basis points (or any basis points) of transaction costs implicitly assumed in the 2009 base ROE determination.

LEI recommended considering the transaction costs associated with equity issuances as operating costs for similar reasons as those for debt issuances. LEI stated that equity issuances do not happen with predictable regularity, which makes it more suitable to recover such costs as and when the utility incurs these expenses.

Concentric disagreed with LEI's exclusion of an adjustment for flotation costs and financing flexibility, which is a departure from the OEB's past practice of allowing an adjustment of 50 basis points. Concentric stated that LEI's approach puts Ontario utilities at risk of not recovering these costs simply because they were not incurred in the test year or are expected to be incurred over the rate plan.

Nexus stated that LEI's proposal that transaction costs be excluded from the ROE and instead be expensed disregarded International Financial Reporting Standards (IFRS) accounting rules. Nexus proposed to increase the deemed ROE by 50 basis points to account for flotation/transaction costs.

Similar to his response regarding debt financing transaction costs, Dr. Cleary believed that the current practice of adding 50 basis points to the allowed ROE estimates seemed reasonable, since it embedded the actual costs of equity financing related to new equity issues into the cost of equity, as in his view, they should be.

Submissions

OEB staff noted that although the deemed ROE included a 50 basis point adder for "transactional costs" since the 2009 Report, the 2009 Report provided no rationale for embedding such costs in the ROE, nor for how the adder was set at 50 basis points. In OEB staff's view, it was time to revisit this aspect of OEB policy and it became clear in the oral hearing that whatever justification there may have been for the 50 basis point adder in 2009, it is not needed today. AMPCO/IGUA agreed.

OEB staff recommended that the adder be eliminated and that instead, utilities be given an opportunity to recover their actual transaction costs in a rate application.

OEB staff noted the following put forth by the two utility experts that recommended that the 50 basis points adder be retained:

- According to Concentric's evidence, flotation costs for utilities are within a range from 2% to 10%, with an average of around 5%. A 5% average translates into about 25 basis points of ROE. Concentric also opined that an additional cushion for "financial flexibility" was needed.
- Nexus argued that in addition to direct transaction costs such as professional fees (lawyers, accountants, rating agencies), the ROE must also account for share dilution. However Nexus was unaware of any other regulator that treats share dilution as a cost of equity recoverable from ratepayers.

OEB staff agreed with LEI that a 50 basis point adder "is likely to overcompensate utilities" and that there were two ways this could be remedied (with the first option recommended):

1. Utilities would be able to include transaction costs in the revenue requirement they seek in a rate application. A deferral account could be established (either on a generic basis or on the application by a utility) to track any transaction costs incurred between rebasing applications.

2. The adder would be reduced to more closely reflect actual transaction costs. The evidence of actual costs was weak, but indicated that an adder of around 25 basis points would be more than sufficient to capture actual costs.

OEB staff stated that it was not persuaded that utilities who do not actually incur transaction costs should get the benefit of the adder. The EDA submitted that contrary to OEB staff's characterization of transaction costs as a "benefit" that should not accrue to utilities that do not incur these costs was incorrect; in an exercise of modelling the deemed cost of capital, irrespective of ownership, transaction costs were a component of that cost that needs to be deemed along with the rest. The EDA stated that since nothing had changed in this regard with respect to the 2009 Report, this adder should also not change. While SEC noted that the OEB sets the ROE generically, this does not mean it must include all components generically.

Pollution Probe's submission was in line with OEB staff's second option, but Pollution Probe further stated that utilities should be allowed to come forward with evidence in their rates proceeding should they want to request approval of a higher value.

The EDA argued that the 50 basis point adder should not be discarded absent compelling and convincing evidence that flotation costs have not been incurred. The EDA noted that it has been common practice for Canadian regulators and some U.S. regulators to approve an adder for flotation costs, with 50 basis points being the typical value. However, SEC submitted that many U.S. regulators have rejected recovery of flotation costs outright, and others specifically as part of the ROE.

The EDA noted that the OEB in 2009 had the benefit of a capital markets panel which did not oppose the inclusion of the flotation costs adder.

The EDA also stated that Nexus pointed out that dilution costs are also included. SEC stated that no other expert recognized this as a valid cost to be recovered from ratepayers, and Nexus was not aware of any regulator that supports this view. SEC further stated that Nexus did not propose that customers receive a rebate for the benefits investors gain from share buybacks, which increase share value and are the inverse of dilution.

The EDA stated that Nexus did not address financial flexibility, but an adjustment for flotation costs has also been described (including by Concentric in this proceeding) as taking into account the need for financial flexibility. The OEA also echoed the need for financial flexibility in its submission and several parties referenced a British Columbia Utilities Commission (BCUC) decision in their submissions.[37] SEC submitted that as Dr. Cleary testified, any need for financial flexibility should be addressed through the appropriate capital structure, with a "buffer in terms of additional equity." CME submitted that Concentric provided no evidence as to why an additional 25 basis point adder was the appropriate amount to secure "financial flexibility". CME noted that utilities operating in the U.S. for which Concentric has estimated the transaction costs of equity issuances did not include the adder for "financial flexibility". VECC submitted that there was no justification for including a "flexibility adder" in the ROE.

The EDA and the OEA disagreed with LEI's proposed approach for flotation costs and recommended that a 50 basis points addition to the ROE was justified. The OEA stated that parties' positions on flotation and financial flexibility costs were generally split

[37] The OEA stated that financial flexibility means that utilities are capital intensive businesses and must be able to access capital markets at all necessary times regardless of conditions or the economy.

between the ratepayer groups and the utility groups. The OEA further stated that a flotation and financial flexibility adjustment to the ROE is required to meet the FRS because to eliminate that adjustment would reduce utilities' access to capital and would put them at a relative disadvantage to peers, failing the comparability standard of the FRS.

The EDA asserted that "if the Board were to remove flotation costs from its authorized ROE, it would be effectively confiscating from utilities their as-yet-unrecovered past equity costs. This is because the historical 50 basis points adder reflects an amortization over infinity."

OEB staff noted that the EDA's statement ignores the fact that many Ontario utilities, which were created through the industry restructuring over 20 years ago, have never actually incurred equity transaction costs. OEB staff noted that to the extent they have incurred transaction costs, there was every reason to believe that utilities were over-compensated for those costs by the excessive 50 basis point adder and replacing the adder should be seen as a correction, not a confiscation.

CCC submitted that the 50 basis points adder has been overcompensating utilities since its introduction (and certainly over the past 15 years) as there are nearly no actual equity-related transaction costs incurred by Ontario's rate-regulated utilities. CCC concluded that there are no "unrecovered past equity costs" (as stated by the EDA) that are remaining to be recovered. SEC stated that the EDA provided no evidence of "effectively confiscating from utilities", and given how much higher the current premium is than actual flotation costs, it is unlikely to be true.

AMPCO/IGUA stated that going forward, an allowance for reasonable and demonstrable actual financing costs should be recoverable through an appropriate mechanism, but not through "an unsupported and apparently over-compensatory 50 basis points ROE adder." A number of ratepayer groups suggested that there was no evidence in this proceeding that was produced to support any such costs. If the OEB determined that it did not have sufficient evidence to award a properly calibrated adder, then CME submitted that LEI's proposal was appropriate.

A number of ratepayer groups suggested that there should be no transaction costs included in the base ROE. Several ratepayer groups suggested that the OEB should establish a generic deferral account that will come into effect at the time of each utilities next rebasing, which would allow the utilities to record actual transaction costs associated with equity issuances. SEC stated that the largest component of flotation costs for public issuances is the underwriter's discount, a cost that privately held companies, such as those owned by the province and municipalities, did not incur.

Findings

The flotation cost adder of 50 basis points currently added to the ROE presents several difficulties in addressing costs attributed to have been incurred by Ontario utilities for maintaining equity.

The adder is meant to recognize expenses such as underwriting fees, legal fees, and registration fees associated with the raising of equity capital by the utility. As OEB staff has noted in their submission, “very few Ontario utilities depend (or have ever depended) on the public equity markets, and even then, it is typically the corporate parent that is listed, not the regulated utility itself (e.g. Enbridge Inc. rather than Enbridge Gas Inc., or Hydro One Limited rather that Hydro One Networks Inc.).”[38]

The 2009 Report does not provide any information on the derivation of the 50 basis point figure included in the ROE formula or on the approach of adding this to the ROE. In this proceeding, it is noted by utility submissions that as the previous costs of raising capital were to be included for recovery in the utility ROE, its termination at this juncture would strand the utilities that have incurred the costs with unrecovered expense. Nexus stated that the flotation adder needed to remain in perpetuity because the flotation costs are amortized over infinity. The difficulty with this statement is that there is no evidence on the record that the costs were scrutinized in the first place, and certainly not in the 2009 Report.

Concentric argued that the equity on the balance sheet “got there somehow”[39] and the flotation cost adder provides a “buffer for financial flexibility … associated with maintaining and having continued access to equity in these markets”. Concentric also explained that the financial flexibility component is “a Canadian precedent, it’s not a U.S. precedent”.[40] None of the experts provided evidence on the magnitude of the actual costs to support the addition of 50 basis points to the ROE. Each of them relied on the fact that 50 basis points was added in the past, although no one could provide an empirical basis for the inclusion of 50 basis points.

[38] OEB Staff Submission November 7, 2024, p. 25.
[39] Transcript Volume 3, p. 26.
[40] Transcript Volume 3, p. 36.

Based on the 2023 fixed assets for rate-regulated utilities of $76.4 billion,[41] a rough average equity thickness of 40% and flotation costs of 50 basis points (0.5%), the total revenue from the flotation adder would be in the order of magnitude of $150 million for the rate-regulated sector.[42] Given the evidence on how rarely equity is issued in Ontario, flotation costs annually in the order of $150 million seem excessive.

The only estimate provided for actual flotation costs was from a 1996 study, which found flotation costs ranged from 2% to 10% of gross proceeds, with an average of 5%, which translates to approximately 25 basis points.[43] This is clearly not strong evidence; however, evidence on the record to support the current 50 basis points is even scarcer. In the OEA's reply submission, it noted that the 1996 study was consistent with recent research by the Enbridge Treasury team, which found that the average flotation costs for a sample of Canadian and U.S. utilities were also equal to 5% of the gross proceeds.

The OEB needs to balance all of these factors:

1. There is limited evidence at best to support a specific number for flotation costs.
2. There are arguments that the equity on the balance sheets of rate-regulated utilities got there somehow and needs to be recovered through a 50 basis point adder to the 2025 base ROE, consistent with the approach from the 2009 Report.
3. There are counter-arguments that actual costs should be recovered going forward through a deferral account, with no adder to the 2025 base ROE.

The OEB is including 25 basis points in the ROE for flotation costs. The base ROE for 2025 is therefore 9.00% (8.75% + 0.25%), on a final basis. While the evidence to support the 25 basis point number is limited, it is better than the evidence to support 50 basis points, either in this proceeding or the 2009 Report. Any utility that can demonstrate that its actual flotation costs materially exceed 25 basis points can file evidence in its next rebasing application to support a higher number. Finally, the lack of evidence for flotation costs in this proceeding has been a challenge. There was also intermingling of the concepts for flotation costs and financial flexibility. This would be alleviated for the next cost of capital review if the OEB specifically sought evidence on this topic.

[41] Undertaking J2.1, October 8, 2024.
[42] Undertaking J2.1, October 8, 2024. The OEB has calculated the approximate amount of $150 million as $76,379 M * 40% * 0.5% = $152.8 M.
[43] Exhibit N-M2-10-OEB Staff-16, August 22, 2024.

3.2.3 Updates to Return on Equity (Issue 10)

Expert Report Proposals

Expert report proposals regarding two key components of the annual ROE adjustment formula (the Long Canada Bond Forecast (LCBF) and Utility Bond Yield Spread) are discussed in Section 3.4 of this Decision in more detail. The adjustment factors components are discussed in more detail below.

LEI stated that the ROE should be updated annually using the adjustment factors of 0.26 for LCBF and 0.13 for utility bond spread.

With respect to annual updating, LEI's proposal was similar to the current methodology of updating the ROE (i.e., with 0.5 adjustment factors for the LCBF and utility bond yield spread). LEI suggested that the annual ROE adjustment formula had 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, LEI concluded that there were no material benefits to changing the status quo approach.

For the annual ROE adjustment formula, Concentric recommended that the OEB set adjustment factors at 0.40 for the LCBF and 0.33 for the utility bond yield spread, which recognized the lower empirical relationship between ROEs and bond yields compared to previous years, while still maintaining the formula's sensitivity to changes in interest rates and utility bond yield spreads.

Nexus did not offer an independent annual ROE adjustment formula, noting only that there was some merit to LEI's use of empirical analysis to establish the weights in the interest rate-based formula.

Dr. Cleary recommended an adjustment factor of 0.75 for both factors, which in his view maintains the relationship between allowed ROEs and certain bond yields, is more responsive to changing market conditions, and will still reduce year-to-year fluctuations in allowed ROEs relative to a weighting of 1.0. Dr. Cleary disagreed with LEI's recommended adjustment factors and noted that the existing adjustment factors of 0.5 would be preferable to LEI's factors.

Submissions

OEB staff submitted that LEI, Concentric, and Dr. Cleary proposed similar annual ROE adjustment formulas for adjusting the ROE beyond 2025, building on the approach approved in the 2009 consultation, but with revised factors. OEB staff stated that while none of the three experts objected to the OEB updating the existing formula, they offered differing views on how parameters should be revised.

OEB staff included a table in its submission which summarized the suggested approaches put forth by the four experts for the DLTDR, separated into two components: the LCBF and Utility Bond Yield Spread. Submissions regarding two key components of the annual ROE adjustment formula (the LCBF and Utility Bond Yield Spread) are discussed in Section 3.4 of this Decision in more detail. Submissions on the adjustment factors components are discussed in more detail below.

The OEA generally supported Concentric's proposals, including changing the LCBF adjustment factor from the status quo 0.50 to 0.40 and the utility bond spread adjustment factor from the status quo 0.50 to 0.33. OEB staff also agreed with the adjustment factors proposed by Concentric. OEB staff submitted that there were valid reasons for not supporting LEI's and Dr. Cleary's recommended adjustment factors. Should the OEB not approve Concentric's adjustment factors, OEB staff noted that it would next recommend maintaining the existing adjustment factor of 0.5 for both factors as a reasonable alternative, as it is balanced between consumers' and utilities' interests.

A number of parties supported maintaining the existing adjustment factors, stating that 0.5 is reasonable. CCC supported an increase to the adjustment factors and stated that the current adjustment factors do not adequately reflect the "passing-through" of the change in bond yields to the ROE.

SEC submitted that it was essential for the annual ROE adjustment formula to balance the impact of macroeconomic and market changes with the need for year-over-year stability. SEC stated that the 50% adjustment factor achieves this balance and should override proposals based on flawed regressions (made by LEI and Concentric). The OEA stated that SEC had not, nor had any expert provided evidence that Concentric's analysis is false.

SEC stated that "the inadequacy of ROE reductions in line with declining bond yields suggests a fundamental issue regarding the relationship between the two, and underscores, that relying on historical relationships is unsuitable for determining specific adjustment factors."

Findings

As established by the 2009 Report, the OEB currently adjusts the ROE each year. The adjustment attempts to adapt the base ROE to align with macroeconomic and market changes. The annual ROE adjustment formula currently modifies the base ROE by 50% of the annual changes in the LCBF and the A-Rated Utility Bond Yield Spread, compared to values employed when the base ROE was first set.

The OEB does not find that a reduction or increase in the adjustment factors is warranted, and therefore they will remain at 50%. The request for a reduction of the factors is supported by a regression analysis by Concentric based on U.S. authorized ROE and U.S. Treasury Bond yields. Concentric argued that the strength of the relationship between utility cost of equity and the LCBF has weakened over time. Dr. Cleary correctly noted that the decline in ROEs has not matched the decline in government and utility bond yields since 2004 and recommended an increase in the adjustment factors. Balancing both these opinions, and the recognition that the energy sector is in a period of energy transition, the OEB will not at this time alter the 50% modification factor.

However, the OEB does agree with Dr. Cleary's recommendation that the OEB should establish the DLTDR based on the Long Canada (30-year Government of Canada) bond yield as at September 30 each year plus the utility bond spread (the spread between the 30-year A-rated Utility Corporate Bond yield and the Long Canada (30-year Government of Canada) bond yield) on the same date each year. This is discussed further in Section 3.4 of this Decision.

If an extraordinary change in market conditions occurs on or before September 30 and extends beyond that date, the OEB concludes that using the October 31 data point as an alternative is reasonable. This approach allows for sufficient time to assess whether market conditions have stabilized before determining the appropriate rate. No specific trigger needs to be adopted for major events such as the 2008-2009 financial crisis or the COVID pandemic – as Mr. Goulding from LEI said in the oral hearing, "we know it when we see it".[44]

Effective for 2026 and forward cost-based rate applications, the OEB's annual ROE adjustment formula shall be:

$ROE_t = 9.00\%^* + 0.5 \times (LCBF_t - 3.13\%) + 0.5 \times (UtilBondSpread_t - 1.38\%)$

[44] Transcript Volume 2, p. 82.

* including 25 basis point flotation cost adder

3.3 Capital Structure

3.3.1 General Approach (Issue 12)

Expert Report Proposals

LEI stated that the OEB's current approach of revising the capital structure upon application if warranted due to an increase in business/financial risks is a reasonable practice, as the OEB has noted that risks rarely change meaningfully in a short period of time. Dr. Cleary generally agreed with LEI's proposition.

LEI believed that adjusting the allowed /deemed equity thickness remains the appropriate lever to address material changes in the utility risk profile. Dr. Cleary supported this approach. LEI stated that 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.

In Concentric's view, risks for Ontario utilities have increased over time and coupled with Concentric's assessment that Ontario's equity ratios are low relative to industry peers, this results in a recommendation that the OEB set a minimum deemed equity ratio for all Ontario utilities of 45%. Concentric recommended increasing OPG's equity ratio in order to meet the FRS, with a specific determination to be made by the OEB as part of OPG's next payment amounts proceeding.

Concentric noted that the 45% level is at a point approximately halfway between the Ontario level and the U.S. average. Concentric was concerned that Ontario equity thicknesses, by being lower across the board than their U.S. peers, do not meet the FRS, but acknowledged that an immediate move to parity with the U.S. would be abrupt.

Concentric found that Ontario's regulated distribution and transmission utilities generally have comparable business risk to the companies in certain proxy groups. Concentric also concluded that Ontario's utilities have similar financial risk to other electric and gas utilities in Canada and substantially greater financial risk than their U.S. peers due to the relatively low deemed equity ratios of 38% for Enbridge Gas, 40% for electric distribution and electric transmission, and 45% for OPG.

Concentric noted that if the OEB maintained the current deemed equity ratios of 38% for Enbridge Gas and 40% for Ontario's electric transmission and distribution utilities, then it recommended adjusting the authorized generic ROE for differences in financial leverage between the Ontario utilities and the proxy group companies. Concentric stated that this would result in an upward adjustment of 138 to 163 basis points to its 10.0% ROE recommendation, based on certain proxy groups and the CAPM analysis using a historical market risk premium.

Concentric recommended that each utility be authorized at its discretion to retain its current equity ratio and also have the ability to propose differences from the generic equity thickness in its rates application.

Concentric noted that historically, the OEB's risk ranking of Ontario utilities placed Enbridge Gas at the low end of the risk spectrum and OPG at the high end, with electricity distributors and transmitters in the middle. Based on industry-segment-specific risks, and, in particular the acute risks to the natural gas distribution segment caused by the energy transition, Concentric found natural gas distribution to be riskier than electric distribution operations.

Nexus proposed that the OEB retain its existing policy for electricity distributors, while noting that the approved equity thickness tends to be higher in the U.S. than in Ontario.

Dr. Cleary recommended that Hydro One's allowed equity ratio be reduced to 38%, and that the OEB consider reducing it further to 36% over the following two to three years. Dr. Cleary stated that the OEB should reconsider the capital structure for Hydro One, given the importance of Hydro One to Ontario's electricity sector, accounting for well over 90% of transmission and over one third of all distribution. Dr. Cleary also considered matters such as Hydro One's credit ratings, the cost of its issued debt, its ability to earn its allowed ROE, and its financial risk and credit metrics.

Dr. Cleary's recommendation for the allowed equity ratio for Enbridge Gas remained at 36%, which was the recommendation provided in his evidence during the recent Enbridge Gas rebasing proceeding (EB-2022-0200). Dr. Cleary did not believe the increase to 38% approved by the OEB in that proceeding was necessary.

Dr. Cleary recommended that the OEB consider reducing Enbridge Gas's allowed equity ratio to 36% over the following two to three years in accordance with the factors that Dr. Cleary discussed in his evidence. Such factors included Enbridge Gas's credit ratings, the cost of its issued debt, its ability to earn its allowed ROE, and its business risk.

Submissions

OEB staff and several ratepayer groups submitted that no changes need to be made to the OEB's policy on capital structure in this proceeding and the default equity thickness should remain at 40% for electricity distributors and transmitters. OEB staff argued that Concentric had not made a persuasive case that a minimum equity ratio of 45% is required to meet the FRS. However, OEB staff and several ratepayer groups agreed with Concentric that OPG's equity ratio should be examined in its next payment proceeding, with APPrO also arguing that OPG's circumstances should be addressed on a case-by-case basis. OEB staff, APPrO, and CCC also submitted that the equity thickness for Enbridge Gas and EPCOR Natural Gas should continue to be determined on a case-by-case basis.

OEB staff stated that Concentric and Nexus were correct that equity ratios in the U.S. are generally higher than in Ontario, but as LEI testified, it may be that U.S. equity ratios are too high, not that Ontario equity ratios are too low. OEB staff noted that Ontario equity ratios are in fact in line with the average equity ratios in other provinces. OEB staff also stated that U.S. utilities tend to be riskier than Ontario utilities, as many U.S. utilities include generation and non-regulated assets.

OEB staff was not persuaded that the overall level of risk facing electricity distributors and transmitters is materially different than in 2009 when the current cost of capital policy was adopted or in 2016 when that policy was last reviewed. OEB staff noted that several ratepayer groups suggested in the oral hearing that the energy transition actually represents a huge opportunity for those utilities. OEB staff also noted that there have been changes to the Ontario regulatory framework that have reduced risk. OEB staff submitted that any change in risk has already been reflected to some extent in the formulaic adjustments to ROE.

In OEB staff's view, Enbridge Gas's equity ratio should not be adjusted in this proceeding, with several ratepayer groups also sharing this view.

OEB staff disagreed with Dr. Cleary's recommendation to lower Enbridge Gas's equity ratio to 36% and his recommendation to revisit Hydro One's 40% equity ratio. OEB staff argued that the equity ratio was a contested issue in Phase 1 of Enbridge Gas's rebasing proceeding that was decided in December 2023. OEB staff also stated that the arguments Concentric made in this generic proceeding for increasing Enbridge Gas's equity ratio were essentially the same as the arguments it made in the rebasing case – including the argument that energy transition has increased risk. OEB staff also noted that the OEB approved a settlement on the equity thickness issue (for both distribution and transmission) in Hydro One's last rebasing case.

The OEA also disagreed with the recommendations regarding Enbridge Gas and Hydro One made by Dr. Cleary. Several ratepayer groups supported Dr. Cleary's recommendations regarding Hydro One.

The OEA generally supported Concentric's proposals. The OEA submitted that in order to meet the FRS, the deemed capital structure for Ontario utilities must be evaluated relative to the proxy group companies, in addition to considering changes in business risk over time. The OEA noted that the risk profile of Ontario utilities has increased over time, warranting a change to the capital structure under the OEB's existing policy. However, if the OEB determines that it is not going to make a change to the deemed capital structure, the OEA submitted that an upward adjustment to Concentric's recommended base ROE is required in order to ensure that the FRS is met (as the recommended base ROE is based on a 45% minimum equity thickness).

In its submission, SEC went further than Dr. Cleary (who recommended a reduction in equity thickness for Enbridge Gas and Hydro One) and suggested that the deemed ratio for all electricity distributors and transmitters be reduced from 40% to 37%, one percentage point lower than Enbridge Gas's current ratio of 38%. SEC noted that the business and financial risks of electricity distributors and transmitters have decreased when compared to Enbridge Gas. CME agreed that the equity thickness could be lowered for electricity distributors. In its reply submission, OEB staff did not agree with SEC that the equity ratio for electricity distributors and transmitters should be lowered in this proceeding by 300 basis points, as there was not enough evidence to support that. The OEA also disagreed with SEC, stating there is no evidentiary support.

SEC was also concerned that there is no requirement for a utility to seek an adjustment to its capital structure when risks decline. In its reply, OEB staff suggested that it would support allowing an intervenor to recommend a utility-specific equity ratio lower than the generic ratio and that intervenors have access to funding, including funding for retaining experts.[45]

SEC and CME also suggested that the OEB should initiate a second phase of this proceeding to lower the equity thickness for electricity distributors and transmitters. In its reply submission, OEB staff indicated that it would not support that option, as parties

[45] Section 30 of the *Ontario Energy Board Act, 1998.*

have already had ample opportunity to put forward their own expert evidence and test the evidence of the other experts.

SEC stated that it had expected that, as part of this proceeding, the OEB would assess the capital structure of electricity distributors and transmitters. SEC suggested that a case-by-case approach might work for the largest distributors and transmitters, but it makes little sense and does not promote regulatory efficiency if applied to all other utilities. SEC stated that electricity distribution and transmission ratepayers have been waiting a long time for the deemed equity ratio to be re-examined.

CCC submitted that the OEB should maintain the current 40% equity ratio for electricity distributors and transmitters, if the OEB was to agree with its proposal to determine natural gas utilities' and OPG's ROE separately at their next rebasing proceedings (i.e., not as a single figure applicable to all regulated entities). If the OEB was to disagree with that proposal (and that it will continue to use the capital structure to reflect the risk differential between sectors), CCC took a similar position as SEC, that risks have decreased and the equity ratio for electricity distributors and transmitters should be reduced to 36%. The OEA disagreed with CCC, stating there is no evidentiary support. AMPCO/IGUA endorsed the submission of SEC.

CCC submitted that the ROE and the equity thickness were directly related and should be established by the OEB at the same time, as both must be considered in the determination of whether the FRS is met. The OEA stated that there was no disagreement amongst the parties that the ROE and capital structure must be assessed together to determine whether the FRS is met.

OEB staff and several ratepayer groups also suggested that there is no basis to conclude that an increase in equity thickness for Ontario's electricity utilities is warranted. CME further stated that the OEB should not accept a simple comparison of capital structures between Ontario utilities and Concentric's proxy groups without a significant adjustment. CME stated that the OEB should instead review the different categories of utility and determine whether or not the equity thickness can be lowered based on the evidence tendered for each category. CCC noted that any comparison to U.S. utilities regarding equity thickness is unfounded, agreeing with Dr. Cleary that U.S. utilities are not reasonable comparators for Canadian utilities.

VECC submitted that decisions regarding capital structure need to focus on differences in financial and business risk between the regulated utilities whose capital parameters are being set and those in the relevant proxy group.

VECC and CCMBC noted that in the case of the OEB, the current approach is to set a uniform ROE that is applicable to all utilities and then recognize difference in risk through the setting of the capital structure. VECC stated that it and the experts participating in this proceeding are generally supportive of this approach. In the case of the re-assessment of a specific utility's capital structure as part of a rebasing (or other) application, VECC submitted that the focus should be on whether the business and financial risks faced by the utility have changed materially since the last generic cost of capital proceeding.

Findings

The OEB has reviewed the appropriateness of the capital structure for electricity transmitters, electricity distributors, natural gas utilities, and OPG considering the FRS. As part of the 2009 Report, the OEB determined that a deemed capital structure of 60% debt (including a 4% short-term debt component), and 40% equity was appropriate for all electricity distributors. After the 2009 Report was issued, the deemed capital structure was set for electricity transmitters on the same basis. The OEB is maintaining this same deemed capital structure for all electricity distributors and transmitters.

For OPG and the natural gas utilities, the OEB had previously determined the deemed capital structure on a case-by-case basis. OPG's current capital structure has been set at 55% debt and 45% equity, and the OEA through its expert witness, Concentric, has recommended that, given OPG's unique business model, first-of-a-kind investments and heightened overall risk, the utility should bring forward a proposal and evidence in its next payment amounts application. The OEB agrees with this recommendation and will consider OPG's proposal, should OPG choose to submit one, as part of its next payment amounts application expected to be filed in the 2025 calendar year. Any proposal by OPG to change its capital structure will be reviewed by the OEB on its merits at that time.

The OEB does not accept the premise that, if the deemed capital structure remains unchanged, an upward adjustment to the base ROE is necessary to satisfy the FRS. The FRS does not prescribe a fixed relationship between capital structure and ROE; rather, it requires that the allowed return be comparable to those available to enterprises of similar risk, enabling a utility to attract capital on reasonable terms. The OEB assesses fairness from a total return perspective and finds that the existing deemed capital structures continue to satisfy the FRS.

The OEB recently approved a change to Enbridge Gas's capital structure. In its Decision and Order dated December 21, 2023 (EB-2022-0200), the OEB authorized an increase in Enbridge Gas's equity thickness from 36% to 38%, effective January 1, 2024.[46] This adjustment reflected the OEB's recognition of the evolving business environment, and the associated risks faced by Enbridge Gas, both increasing and decreasing. Because Enbridge Gas's equity thickness was recently determined by the OEB, there is no basis to revisit that decision in this proceeding. The OEB agrees with OEB staff and other parties who submitted that it would not be appropriate to reconsider Enbridge Gas's capital structure at this time.

As a result, Enbridge Gas's approved capital structure, as of January 1, 2024, is 62% debt and 38% equity. Consistent with OPG, Enbridge Gas may propose modifications to its capital structure in its next rebasing application.

For EPCOR Natural Gas (Aylmer service territory), the OEB recently approved a settlement agreement in which parties agreed to a 40% equity ratio and the use of the OEB's generic ROE.[47] EPCOR Natural Gas' 36% equity ratio for the South Bruce service territory shall continue to remain in place until its next rebasing.[48] At that time, the OEB can determine whether a 40% equity ratio should also apply for the South Bruce service territory, or some other ratio.

In summary, the OEB concludes that the current deemed capital structure for electricity distributors, transmitters, OPG, and natural gas utilities remains appropriate and continues to satisfy the FRS.

The OEB also acknowledges several parties' comments on decreasing Hydro One's equity ratio, as suggested by Dr. Cleary in his expert report. Hydro One, or any party, can seek modifications to Hydro One's deemed equity ratio, with commensurate evidence, in its next rebasing application in which the specific risks of Hydro One could be assessed.

In general, the OEB is maintaining its current approach of permitting utilities to apply for a change in capital structure if they believe there has been an increase in the business or financial risks they face. However, to address concerns made by SEC, the OEB finds OEB staff's suggested approach reasonable that in a rebasing application an intervenor may propose a utility-specific equity ratio lower than the generic ratio and can request funding to support such a proposal for consideration by the OEB.

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[46] EB-2022-0200, Enbridge Gas Inc., Decision and Order, December 21, 2023, p. 67.
[47] EB-2024-0130, Exhibit 5, Tab 1, Schedule 1, Page 8, July 18, 2024; EB-2024-0130, Decision and Order, January 14, 2025, Settlement Proposal, November 20, 2024, p. 25.
[48] EB-2018-0264, Exhibit 5, Tab 1, Schedule 1, Page 2, April 11, 2019.

SEC expressed concerns that it had expected that, as part of this proceeding, the OEB would assess the capital structure of electricity distributors and transmitters. The OEB will not conduct a second phase to this proceeding despite these comments. The issues list for this proceeding clearly included capital structure, and SEC or another intervenor could have led their own evidence on this issue if it was a priority. Whether a more detailed review will be conducted in five years' time will be determined as part of that proceeding.

With respect to energy transition, the OEB is not persuaded that the energy transition has resulted in a material increase or decrease in the overall level of risk faced by electricity distributors and transmitters compared to the risk levels considered in the 2009 Report or in the Staff Report. While some parties argued that the energy transition introduces new risks, the OEB finds that the unfolding transition also presents opportunities for electricity utilities, particularly through increased demand for electricity and expanded investment in system infrastructure.

For example, the growing electrification of transportation and heating is expected to drive long-term increases in electricity demand, leading to higher revenues and greater asset utilization for electricity distributors and transmitters. Similarly, provincial and federal policies supporting grid modernization, energy storage, and distributed energy resources create new investment opportunities that could expand the regulated asset base of these utilities. Additionally, the OEB has responded to a myriad of circumstances (e.g., the COVID pandemic, the roll out of Ontario's broadband initiative, cloud computing) with regulatory tools including DVAs to mitigate potential financial volatility. These mechanisms have provided greater stability and mitigated overall risk exposure. The OEB will likely continue with this broadly supportive policy stance in the future.

The OEB also notes that any incremental changes in risk have already been reflected, at least in part, through the formulaic adjustments to ROE over time. Accordingly, the OEB does not find that the energy transition warrants an adjustment to the deemed capital structure or a departure from the current 2009 Cost of Capital Framework. Energy transition is discussed further in Section 3.1 of this Decision.

While some of the expert evidence in this proceeding has suggested that Ontario's utilities have lower deemed equity thicknesses compared to the selected North American proxy sample, thereby implying a competitive disadvantage, the OEB is not persuaded that a change in the current capital structure is warranted. As noted elsewhere in this Decision, the determination on cost of capital parameters and capital structure arising from comparison to the decisions of regulators in U.S. jurisdictions must be scrutinized to ensure comparability and relevance. Differences in utility risk often reflected in the higher betas for U.S. energy utilities[49] make conformance unlikely. Fortunately, the OEB has a considerable historical record for its current deemed capital structure.

Absent capital market dislocations (such as the period at the start of the COVID pandemic, and the weeks just prior to the significant and coordinated policy response to the COVID pandemic from central banks), Ontario's utilities have consistently demonstrated their ability to access both debt and equity capital as needed and on favourable terms. Recent financings by Ontario utilities continue to occur at rates that compare favourably to market benchmarks, further supporting the conclusion that the existing deemed capital structure remains appropriate.[50] This indicates that the current capital structure supports financial integrity, maintains comparability to alternative investments, and ensures capital attraction, thereby meeting the requirements of the FRS. The OEB also observes that the capital structures for Ontario's utilities are broadly consistent with those approved for utilities in other Canadian provinces. This further supports the reasonableness of the current deemed capital structure.

3.3.2 Single-Asset Transmitters (Issue 13)

Expert Report Proposals

LEI recommended that the current approach of allowing the same equity thickness for all electricity transmitters should be maintained: Hydro One and smaller, single-asset transmitters should all have the same equity thickness.

LEI noted that size is less of an issue for Ontario's electricity transmitters as transmitters have essentially one customer: the IESO. LEI stated that transmitters (big and small) cannot diversify customer risk or economic risk but are likely insulated from volume risk based on their tariff structure. LEI also stated that the risk profile of electricity transmitters is similar to, if not lower than, that of electricity distributors. LEI concluded that it is reasonable to consider the same approach to setting capital structures as electricity distributors.

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[49] Dr. Cleary Expert Report, July 22, 2024, p. 29.

[50] For example, refer to Dr. Cleary Expert Report, July 22, 2024, p. 118. Dr. Cleary noted that the market determined yield on Hydro One's long-term bonds was less than or equal to the average Canadian A-rated utility yield. Dr. Cleary concluded that Hydro One is able to attract debt capital at rates that correspond to those of similar low-risk entities.

Concentric disagreed and noted that LEI's views do not consider the unique risks of transmission development, and the extent to which they are proportionately greater for a single-asset developer lacking the diversity of revenues and cash flows of a diversified transmission (or transmission and distribution) owner in Ontario. Concentric also argued that reliance on one customer, the IESO, if anything increases risk. Concentric also stated that this is not a size issue; it is a matter of diversifiable business risk, which a single-asset transmitter does not possess and noted that entities can be established on a stand-alone basis for purposes of raising capital.

Concentric did not make specific recommendations regarding a risk premium that may be warranted for single-asset transmitters. Concentric noted that such a differential could be supported in the context of utility specific rates applications.

Concentric viewed single-asset transmission utilities as bearing distinct risks related to a lack of diversification that warrant a higher equity ratio than multi-asset transmitters. Concentric noted that development risks, however, are borne by transmitters more generally, regardless of whether they own a single or multiple assets.

Submissions

OEB staff agreed with LEI that the current approach of allowing the same equity thickness to all electricity transmitters (and distributors) should be maintained, even if it is a single-asset transmitter. OEB staff submitted that the risk profile of electricity transmitters is similar to, if not lower than, that of electricity distributors and single-asset transmitters do not necessarily have increased risk.

OEB staff agreed with Concentric that such a risk premium differential could be proposed in the context of utility-specific rates applications (and not in the current proceeding), with respect to the allowed ROE and equity ratio. OEB staff submitted that there is no evidence in this proceeding to warrant a different approach to setting a different allowed ROE or equity ratio for single-asset transmitters.

The OEA generally supported Concentric's proposals.

CME submitted that the OEB should not differentiate between single- or multiple-asset transmitters simply on that basis. However, CME stated that the OEB should set the capital parameters and cost of capital for specific transmitters differently where they materially depart from their peers with respect to business or financial risk.

With respect to single-asset transmitters, CCC submitted that these companies have similar risk as transmitters that own and operate multiple assets. Several ratepayer groups submitted that there is not a valid reason to treat single-asset and multiple-asset transmitters differently from a cost of capital perspective.

Several ratepayer groups did not support a relative increase in the equity ratio for single-asset transmitters compared to multi-asset transmitters, noting that single-asset transmitters have lower risk, and may be accorded a lower equity ratio.

Minogi/TFG requested that the OEB provide a risk premium to the equity ratio for single-asset transmitters in cases of Indigenous equity participation that satisfies a reasonable materiality threshold, reflecting the fact that the capital treatment for single-asset transmitters should reflect the higher levels of risk involved. Minogi/TFG stated that the OEB's determinations concerning the capital structure for single-asset electricity transmitters will have a significant impact for Indigenous equity participants in Ontario's energy sector, since many First Nations invest mainly or exclusively in single-asset entities. Minogi/TFG agreed with the recommendation of Concentric that precise differentials could be proposed and supported in the context of utility-specific rates applications.

TFG/Minogi stated that a lack of an ability to diversify and thereby reduce risk in the context of equity participation in single-asset transmitters is precisely the challenge that many First Nations face. TFG/Minogi stated that the existing approach therefore can serve as a disincentive to Indigenous investment, working at cross-purposes with the objectives motivating the creation of single-asset transmitters, which are often designed to facilitate Indigenous equity participation. CFN/MCFN generally supported and adopted TFG/Minogi's submissions.

OEB staff was supportive of allowing transmitters – whether they have Indigenous equity or not – to apply for a deviation from the default cost of capital parameters on a case-by-case basis. OEB staff noted that this would be consistent with the current policy set out in the Infrastructure Investment Report.

Findings

The OEB has considered whether a different approach to setting capital structure is warranted for single-asset electricity transmitters versus multiple-asset transmitters (i.e., whether a risk premium should be applied to the equity ratio). The OEB concludes that no distinction is necessary. The current regulatory framework provides a supportive environment for all electricity transmitters, regardless of asset count. Mechanisms such as DVAs effectively mitigate financial risks, ensuring that both single-asset and multiple-asset transmitters have sufficient regulatory protection.

The OEB acknowledges TFG/Minogi's concern that the current approach to capital structure could act as a disincentive to Indigenous equity participation in single-asset transmitters. Nevertheless, the OEB finds no evidence to suggest that single-asset transmitters face heightened financial risk that would justify a different deemed capital structure. Both categories of transmitters have successfully accessed capital under the existing 2009 Cost of Capital Framework, evidenced by the number of new single-asset transmitters since 2009, including those with Indigenous equity participation.[51] This reinforces the conclusion that the current approach remains appropriate and satisfies the FRS. The OEB also agrees with OEB staff and Concentric that a risk premium differential could be proposed in the context of utility-specific rates applications (and not in the current proceeding), with respect to the allowed ROE and equity ratio.

Accordingly, the OEB will continue to apply the same capital structure methodology to all electricity transmitters, irrespective of asset count. The OEB addressed the question of Indigenous ownership in Section 3.1 of this Decision.

3.3.3 Variances from Deemed Capital Structure (Issue 9 and Issue 12)

Expert Report Proposals

LEI recommended that the status quo approach (considering deemed capital structure regardless of the actual capital structure) should be retained. In LEI's view, this ensures fairness to both utilities (flexibility to optimize the capital structure based on firm-specific needs) and consumers (by limiting the deemed share of equity, which has a higher financing cost than debt).

Concentric and Dr. Cleary also recommended maintaining the status quo. Dr. Cleary in particular agreed with LEI's statements that the status quo approach is also administratively simple for the OEB and 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.

[51] The new transmitters in place since 2009 include: B2M Limited Partnership, Chatham x Lakeshore GP Inc., Hydro One Sault Ste Marie Inc. on behalf of Hydro One Sault Ste Marie LP, Niagara Reinforcement Limited Partnership, Upper Canada Transmission 2, Inc., Wataynikaneyap Power GP Inc.

Concentric further recommended that Ontario's regulated utilities should continue to be given the discretion to manage their actual capital structure within reasonable bounds. Concentric noted that this is particularly important for the periods between when the OEB assesses each utility's ratemaking capital structure, as utilities should be given latitude in managing their credit profiles and accessing the debt and equity markets when conditions warrant.

Submissions

OEB staff and several ratepayer groups agreed with LEI and Dr. Cleary that the status quo approach (considering deemed capital structure regardless of the actual capital structure) should be retained. OEB staff noted that this ensures fairness to both utilities (by providing flexibility to optimize the capital structure based on their specific needs) and consumers (by limiting the deemed share of equity, which has a higher financing cost than debt).

OEB staff noted that different methods are used in practice for Ontario utilities to account for differences between the deemed capital structure and actual capital structure. Enbridge Gas and OPG conduct true-ups, but electricity distributors and electricity transmitters do not conduct true-ups.

In the Staff Report, it was noted that the OEB had determined in several cases that notional debt should attract the weighted average cost of actual long-term debt rate (rather than the DLTDR issued by the OEB).[52] An exception to this was where a utility is 100% equity financed.

The OEA generally supported Concentric's proposals. The OEA stated that all experts who commented on this issue (Nexus did not address this issue) agreed that the status quo should be maintained and that the deemed capital structure should determine the debt and equity costs that are recovered in rates.

SEC stated that at issue is whether notional debt attracts a utility's weighted average cost of actual long-term debt rate, the DLTDR, or some other rate. SEC submitted that as long as the OEB uses a deemed capital structure, the appropriate approach is to apply a utility's actual weighted average cost of actual debt to any notional debt. In its reply, the OEA agreed, also noting that utilities should be allowed to come forward with alternative proposals in their rate applications.

[52] Staff Report, January 14, 2016

SEC suggested that a consistent approach to notional debt may not have been used by the OEB in the past, also noting that the 2009 Report did not address this matter. In its reply, OEB staff was of the view that a consistent approach should be decided by the OEB in this proceeding to be used going forward, specifically to clarify what type of debt rate should apply to notional debt (e.g., actual debt rate versus the DLTDR).

VECC submitted that ratepayers should not be at risk for utilities with significant variance between the actual and rate-making capital structure and that the OEB should adjust its policy for pricing notional debt, in particular for significant variations between actual and deemed debt. In its reply, OEB staff agreed. The OEA disagreed and noted that VECC's argument ignores the fact that utilities require discretion in managing their capital structures to maintain credit ratings and take advantage of favourable markets (ultimately benefiting ratepayers).

VECC stated that where a utility exceeds its notional debt, the highest cost debt should be prorated and eliminated until it meets the regulated amount. VECC also stated that conversely, the OEB should price any variance below the regulated amount at the price of the lowest cost of debt in the portfolio. In its reply, OEB staff submitted that notional debt should attract the lower of the weighted average cost of actual long-term debt rate and the DLTDR at the time of issuance, but only when there are material variances relating to the notional debt (i.e., with material impacts on the revenue requirement).

Findings

Electricity Distributors and Transmitters

The 2009 Report affirmed the deemed equity ratio of 40% equity / 60% debt for electricity distributors. Since the 2009 Report, the OEB has extended the deemed equity ratio of 40% to electricity transmitters. The OEB has considered the implications of variances from the deemed capital structure and the impact of variances on the determination of the cost of long-term debt. The OEB finds that the current approach should be maintained.

The OEB's deemed capital structure provides a standardized framework for setting rates, ensuring that electricity distributors and transmitters operate under consistent financial assumptions. The current approach assumes a fixed portion of debt and equity, irrespective of the actual capital structure for these utilities. This methodology balances fairness between utilities and their customers and continues to satisfy the FRS.

The deemed capital structure, for rate-setting purposes, allows electricity distributors and transmitters flexibility in managing their financing in a manner that best suits their specific operational and financial circumstances.

Further, maintaining the deemed capital structure safeguards ratepayers from distortions that could arise from excessive equity or debt financing.

Implications of variances from the deemed capital structure are described below. If utilities' actual capital structure were used instead of their deemed structure, utilities with lower actual debt than deemed debt (positive notional debt) could earn higher returns at the expense of ratepayers as the equity portion and associated ROE would be higher than the debt portion and debt rate. Conversely, utilities with higher actual debt than deemed debt (negative notional debt) could pass on additional costs, as their increased leverage would raise their cost of debt due to higher risk, even though debt remains cheaper than equity. By adhering to the deemed capital structure, the status quo ensures a balanced approach that mitigates these potential inefficiencies.

Under the current approach, the OEB applies the actual weighted average cost of debt to the actual long-term debt of electricity distributors and transmitters. This ensures that utilities recover prudently incurred debt costs while maintaining the integrity of the deemed capital structure. This approach remains appropriate and continues to align with regulatory best practices.

In summary, the OEB finds that no changes are required to the treatment of variances from the deemed capital structure. The deemed capital structure will continue to apply for all electricity distributors and transmitters, ensuring a fair and balanced approach for both utilities and consumers. The existing methodology for determining the cost of long-term debt will also be retained, providing stability and predictability in ratemaking, with clarity being applied to the approach to notional debt.

For notional debt (i.e., debt assumed under the deemed structure but not issued in practice) different approaches have been used in the past – sometimes the DLTDR has been applied and sometimes the weighted average cost of actual long-term debt. The OEB acknowledges VECC's submission that ratepayers should not be at risk for utilities with a significant variance between the actual and rate-making capital structure. VECC further stated that where a utility exceeds its notional debt, the highest cost debt should be prorated and eliminated until it meets the regulated amount. VECC also stated that, conversely, the OEB should price any variance below the regulated amount at the price of the lowest cost of debt in the portfolio. In its reply, OEB staff submitted that notional debt should attract the lower of the weighted average cost of actual long-term debt rate and the DLTDR at the time of issuance, but only when there are material variances relating to the notional debt (i.e., with material impacts on the revenue requirement).

The OEB agrees with OEB staff’s submission. The rate for notional debt will be at the lower of the DLTDR at the time of issuance and the weighted average cost of actual long-term debt, but only when there are material variances relating to the notional debt (i.e., with material impacts on the revenue requirement).

EPCOR Natural Gas

EPCOR Natural Gas’s current approved equity ratio is 36% for its South Bruce service territory and 40% for its Aylmer service territory. The deemed debt component includes a deemed 4% component for short-term debt for both. For all the reasons stated above for Ontario’s electricity distributors and transmitters, the OEB finds that long-term debt costs should be determined by applying actual debt costs for issued debt and the lower of the DLTDR at the time of issuance and the weighted average cost of actual long-term debt to notional debt, but only when there are material variances relating to the notional debt (i.e., with material impacts on the revenue requirement). This treatment is consistent with electricity distributors and transmitters.

Enbridge Gas

The current OEB-approved capital structure for Enbridge Gas is based on a deemed 38% equity component, with the remaining 62% financed through short-term and long-term debt.

The difference is that the deemed structure is not set on a generic basis as it is for electricity distributors and transmitters but is set on a case-by-case basis through an application. In its recent decision in the EB-2022-0200 proceeding, the OEB adjusted Enbridge Gas’s deemed capital structure to 62% debt and 38% equity, reflecting an updated assessment of business and financial risks.[53] In the same application, Enbridge Gas noted that the average amount of short-term debt in its capital structure is the difference between the average utility rate base and the total of the common equity component, and the long-term debt component.[54] That is, the short-term debt ratio is the difference between 100% and the sum of the equity ratio and the long-term debt

[53] EB-2022-0200, Rate Order, Working Papers, Schedule 11, Page 1, February 16, 2024.
[54] EB-2022-0200, Exhibit 5, Tab 2, Schedule 1, Plus Attachments, Page 4, October 31, 2022.

ratio in Enbridge Gas's capital structure.[55] This description aligns with the concept of variances from a deemed capital structure, similar to electricity transmitters and distributors.

The OEB finds that the current approach to determining debt costs — applying actual debt costs for issued long-term debt[56] and forecast debt costs for forecasts of debt issuances is appropriate. Additionally, a forecast of short-term debt rates for the forecast amount of short-term debt[57] for the rebasing period continues to be appropriate for determining Enbridge Gas's debt cost of capital.

With short-term debt acting as a true-up to Enbridge Gas's deemed capital structure, the actual and deemed capital structure are effectively the same (i.e., a deemed 38% equity component, with the remaining 62% financed through short-term and long-term debt). The OEB concludes that this approach satisfies the FRS while ensuring regulatory stability and predictability.

OPG

OPG's current approved equity ratio is 45%. The current OEB-approved capital structure is based on a deemed 45% equity component, with the remaining 55% financed through short-term and long-term debt. As with Enbridge Gas, the deemed capital structure for OPG is set on a case-by-case basis through an application. The current structure reflects OPG's unique business risks and capital-intensive operations, particularly in nuclear generation. Maintaining this deemed capital structure ensures that OPG does not over-recover or under-recover costs due to its financing decisions, thereby balancing investor confidence with ratepayer protection.

As LEI noted in its report, for OPG, the DSTDR is not used to set short-term debt rates for OPG.[58] Instead, short term debt is used to true up the deemed capitalization to OPG's actual capitalization, and short-term debt effectively makes up the unfunded portion of OPG's capital structure. The OEB understands that the amounts involved have typically been small.[59] In rate applications, OPG provides forecasts of short-term debt rates based on its actual debt portfolio.

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[55] As noted in OEB Staff Submission, November 7, 2024, p.8: An "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%.
[56] EB-2022-0200, Exhibit 5, Tab 2, Schedule 1, Plus Attachments, Page 8, October 31, 2022.
[57] EB-2022-0200, Exhibit 5, Tab 2, Schedule 1, Plus Attachments, Page 4, October 31, 2022.
[58] LEI Expert Report, June 21, 2024, Revised September 23, 2024, p. 77.
[59] For example: refer to EB-2020-0290, Exhibit C1, Tab 1, Schedule 1, Table 1, December 31, 2020.

Similar to Enbridge Gas, the OEB finds that the current approach for determining debt costs — applying actual and forecast debt costs for issued long-term debt[60] and a forecast of short-term debt rates to the forecast amount of short-term debt[61] — for the rebasing period continues to be appropriate for determining OPG's debt cost of capital.

Like Enbridge Gas, with short-term debt acting as a true-up to OPG's deemed capital structure, the actual and deemed capital structure are effectively the same (i.e., a deemed 45% equity component, with the remaining 55% financed through short-term and long-term debt). The OEB concludes that this approach satisfies the FRS while ensuring regulatory stability and predictability.

3.4 Long-Term Debt Rate

3.4.1 Approach to Long-Term Debt (Issue 6 and Issue 7)

Expert Report Proposals

Calculation of Deemed Long-Term Debt Rate

This section covers the proposals made by the experts regarding the DLTDR. As explained earlier in this Decision, the DLTDR is currently the sum of the LCBF and Utility Bond Yield Spread.

The following table is from OEB staff's submission which summarizes the suggested approaches recommended by each expert for the DLTDR.

Table 1 – Summary of Suggested Approaches for the DLTDR

Expert	LCBF	Utility Bond Spread
Status Quo (2009 Report)	10-year Government of Canada bond yield forecasts (from Consensus Forecasts) plus yield spread of 30-year Government of Canda bonds over 10-year Government of Canada bonds	Average spread between a 30- year A-rated Canadian utility bond yield and 30-year Government of Canada bond yield for the month of September
LEI	30-year bond yield forecasts from the seven major Canadian banks	Average spread between a 30-year A-rated Canadian utility bond yield and 30-year Government of Canada bond yield

[60] EB-2020-0290, Exhibit C1, Tab 1, Schedule 2, Page 3, December 31, 2020.
[61] EB-2020-0290, Exhibit C1, Tab 1, Schedule 3, Page 1, December 31, 2020.

Expert	LCBF	Utility Bond Spread
		for the trailing 12 months as of September 30
Concentric	Average of: • The forecast of the quarterly 30-year Government of Canada bond yield for each of the four quarters in the coming year from three Canadian investment banks – which receives a 75% weight; and • The current 90-day average 30-year Government of Canada bond yield, which receives a 25% weight	Average spread between a 30-year A-rated Canadian utility bond yield and 30-year Government of Canada bond yield for the trailing 90 days as of September 30
Nexus	No comments made on the DLTDR	
Dr. Cleary	Actual 30-year Government of Canada bond yield, as at September 30	Actual spread between a 30-year A-rated Canadian utility bond yield and 30-year Government of Canada bond yield, as at September 30

No expert disagreed with the use of Bloomberg's BVCAUA30 BVLI Index, as recommended by LEI, when calculating the spread over LCBF for an A-rated utility.

Concentric suggested that an additional consideration is that not all Ontario utilities have an A-rating and the OEB should monitor any impacts on the DLTDR for utilities that have different credit ratings.

Using Canadian data over the 2011-2023 period, Dr. Cleary concluded that using existing Government of Canada 30-year bond yields produced statistically significantly more accurate forecasts of actual Government of Canada 30-year bond yields in the subsequent period than using forecasts. Dr. Cleary stated that there is an upward bias in forecasts of approximately 0.4%, which in his view, was substantial.

Use of the DLTDR

No expert took issue with the OEB’s general policy to rely primarily on the embedded or actual cost for existing long-term debt instruments. The experts disagreed on whether the DLTDR should be used as a cap in certain circumstances.

LEI and Dr. Cleary recommended that the DLTDR should be applied as a cap for all utilities. LEI noted that all OEB-regulated entities reviewed have a similar senior debt credit rating, and there is no reason to subject only electricity distributors and transmitters to a cap.

Concentric disagreed and stated that utilities should be allowed to forecast debt rates for debt that will be incurred during the rate plan, subject to review and approval by the OEB. Concentric also stated that the general use of embedded debt costs of each individual utility company is reasonable and appropriate for previously-incurred debt. If the OEB were to modify its approach to the DLTDR, Concentric suggested considering a long-term debt rate benchmarking intended to confirm that the OEB's DLTDR is within reasonable error-bounds of actual utility debt costs.

Submissions

Calculation of DLTDR

OEB staff and Pollution Probe supported LEI's suggested approach. OEB staff noted that using updated data as at September 30, 2024, the base LCBF should be 3.127% and the base utility bond spread should be 1.427%, summing to a DLTDR of 4.554%.[62]

The OEA generally supported Concentric's proposals. Concentric recommended reliance on bank forecasts for the 30-year bond yield and 90-day averages for spreads, versus using 30 days for the month of September data.

The OEA noted that Dr. Cleary's reference to a 0.4% bias was not a compelling reason to alter the current approach. In the OEA's view, given that the costs of long-term debt will be carried into the future, setting the LCBF should require a forecast to estimate the actual costs in the future of that debt.

AMPCO/IGUA stated that regarding the DLTDR, Dr. Cleary demonstrated that the use of actual observed 30-year bond yields produces more accurate results than using forecast bond-yields. AMPCO/IGUA stated that Dr. Cleary's analysis indicated an upward forecast bias relative to actuals of approximately 0.4%. CCC agreed.

CCC submitted that the OEB should establish the DLTDR based on the current 30-year Government of Canada bond yield on September 30 each year plus the utility bond spread (based on the current A-rated utility bond yield) on the same date each year,

[62] Undertaking Response J2.2, October 8, 2024.

thereby using Dr. Cleary's approach. Dr. Cleary updated his analysis using September 30, 2024 data and calculated a DLTDR of 4.51% using this approach.[63] CCC submitted that Dr. Cleary's approach of using the current information on September 30 each year was simpler, more transparent, and will result in more accurate results.

SEC agreed with Dr. Cleary that actual prevailing 30-year Government of Canada bond yields should be used, as they reflect what investors today consider risk-free and are therefore more accurate. However, SEC stated that instead of using the actual 30-year Government of Canada bond yield as at September 30 (i.e., one data point, as recommended by Dr. Cleary), SEC suggested that the OEB consider averaging yields over a slightly larger range, such as five days, to smooth out daily fluctuations that may be due to "noise". SEC did not have as strong a view on the appropriate length of time to calculate the utility bond yield spread over the LCBF.

With respect to long-term Government of Canada yields, VECC noted that the OEB's current formula uses 30-day historical averages. VECC submitted that this represented a reasonable compromise between the approaches suggested by Concentric and Dr. Cleary and should continue to be used.

CME and CCMBC submitted that the use of actual bond yields might be preferable, but CME noted that using forecasts also seemed like a reasonable option.

Use of the DLTDR

No party took issue with the OEB's general policy to rely primarily on the embedded or actual cost for existing long-term debt instruments. As with the experts, the point of disagreement was whether the DLTDR should be used as a cap.

OEB staff noted that currently for electricity distributors and transmitters, the DLTDR serves as a ceiling in certain instances. OEB staff and several ratepayer groups submitted that the DLTDR should be applied as a cap for all utilities (not just electricity distributors and transmitters which is the OEB's current approach). OEB staff noted that OEB-regulated entities have similar credit ratings and this may potentially incentivize utilities to improve their credit profile and/or negotiate better borrowing terms, if their rates are higher than the DLTDR.

Although CCC submitted that the same approach should apply to Enbridge Gas and OPG regarding the use of the DLTDR as a cap, CCC noted that these utilities should be

[63] Undertaking 5.3, October 16, 2024, p. 5.

allowed to apply for a different approach to long-term debt if they believe that is appropriate. CME agreed and called this a soft cap that the utility could rebut through evidence.

The OEA generally supported Concentric's proposals. The OEA noted that the impact of applying a cap to Enbridge Gas and OPG would result in a material under-recovery of their actual prudently incurred cost of long-term debt. The OEA suggested that there is no evidence in this proceeding that the current practice has been at any time problematic. Further, the OEA stated that capping all utilities at the DLTDR would not be reflective of the spectrum of credit ratings assigned to regulated utilities.

OEB staff recommended that for affiliate debt with a fixed rate, the DLTDR at the time of issuance should continue to be used as a ceiling on the rate allowed for that debt, as set out in the 2009 Report.[64] OEB staff and VECC submitted that the OEB should clarify that its current policy is designed to ensure utilities are borrowing at market rates, even in scenarios where a regulated utility's borrowings are done through a parent or holding company.

OEB staff and VECC submitted that any debt which is negotiated on a non-arms length basis (i.e., not market based debt) should be subject to a ceiling using the DLTDR at the time of issuance, to further ensure that utilities are borrowing at rates similar to market rates.

Findings

The DLTDR will continue to be applicable to all electricity distributors and transmitters, as well as EPCOR Natural Gas (both Aylmer and South Bruce), rebasing rates in 2025 and beyond, in prescribed circumstances, unless some other approach was previously approved by the OEB.

For OPG and Enbridge Gas, the DLTDR will not be applied as a cap on the unfunded portion of the capital structure (the portion of the capital structure to reach 100%). The OEB will assess whether the cost of debt has been prudently incurred, and the DLTDR will be considered as part of that assessment. OPG and Enbridge Gas are expected to demonstrate that they have been prudent in their debt management. In determining that prudence, the OEB will assess the management of debt and the processes the utility has in place to manage their treasury functions.

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[64] 2009 Report, p. 53.

The OEB concludes that the approach to long-term debt has generally worked well and will continue, with certain modifications to how the DLTDR is calculated and clarifications on its applicability.

- Actual market-based debt should be used when available.

In setting the cost of long-term debt for a rate term, utilities will continue to use their actual weighted average embedded debt plus forecasted debt. The cost of debt is one of the many costs that the OEB tests in rate rebasing applications. The OEB concludes it is appropriate to use utilities' embedded cost of debt and forecast of debt in setting rates, just like it uses actual fixed assets and forecast capital expenditures in establishing a rate base. However, there do need to be exceptions discussed in this section when the embedded debt is not market-based, and therefore the OEB is also setting a DLTDR.

The OEB remains of the view that there should be greater reliance on actual and forecast embedded debt costs for the utilities, as was stated in the 2009 Report.[65] When debt is market-based, there is greater assurance to the OEB that the cost of debt is reasonable.

- The current formula for setting the DLTDR is reasonable with some amendments to how the terms of the formula are determined.

The OEB will set a DLTDR annually. The rate for 2025 is 4.51% on a final basis. The formula will remain as follows below, with changes to how the LCBF and utility bond spreads are determined:

$DLTDR_t = LCBF_t + UtilBondSpread_t$

Where:

> $LCBF_t$ is the Long Canada (30-year Government of Canada) Bond yield as at September 30 for year t.
>
> $UtilBondSpread_t$ is the spread between the 30-year A-rated Utility Corporate Bond yield (taken from ticker Bloomberg BVCAUA30 BVLI Index) and Long

[65] 2009 Report, p. 54.

Canada (30-year Government of Canada) Bond yield (taken from Bank of Canada series V39056) as at September 30 for year t.

The DLTDR will be calculated as the sum of the LCBF, which will be calculated using the actual Long Canada (30-year Government of Canada) Bond yield, which was 3.13% in 2024, plus the actual spread between 30-year A-rated Utility Corporate Bond yield and Long Canada (30-year Government of Canada) bond yield as at September 30, which was 1.38% in 2024 (3.13% + 1.38% = 4.51%).

Using September 30 data points provides ample time for utilities who use the DLTDR to incorporate the updated value into their rate applications.

If an extraordinary change in market conditions occurs on or before September 30 and extends beyond that date, the OEB concludes that using the October 31 data point as an alternative is reasonable. This approach allows for sufficient time to assess whether market conditions have stabilized before determining the appropriate rate. As discussed in Section 3.2.3, no specific trigger needs to be adopted for major events such as the 2008-2009 financial crisis or the COVID pandemic.

This approach of using actual values is simpler because it does not require a forecast of yields or an estimate of the spread between 10-year and 30-year government bond yields. Given that the DLTDR is a substitute for when a utility does not have market-based debt, the OEB concludes that using the simplest approach is preferable. Evidence filed by Dr. Cleary also demonstrated that using actual values instead of a consensus forecast has been more accurate from 2011 to 2023.

- The DLTDR shall be used as a ceiling when there is no debt, variable or callable debt or debt that is not market-based.

Unlike the deemed ROE, which generally applies to all utilities, the DLTDR is used as a ceiling for specified kinds of debt. Ideally, there would be no need to use it because all utilities would source long-term debt in the capital markets up to their established capital structure. However, this is often not the case for smaller municipally owned distributors. Furthermore, not all electricity distributors and transmitters borrow up to their deemed debt level.

As per the 2009 Report, the DLTDR at the time of issuance will apply as a ceiling for electricity distributors and transmitters when the utility has:[66]

- variable rate debt
- debt without a fixed term
- no debt
- debt that is callable during the rate term

With respect to affiliated debt, the DLTDR will apply as a ceiling for electricity distributors and transmitters for all debt held with a municipal government shareholder at the time of issuance.

For affiliated debt held by the holding company, other affiliated company or related party of a rate regulated utility, the utility must explain how the debt rate is no higher than it would have been if funds were borrowed directly by the utility through the external markets. For example, the utility must identify reasons why the holding company has no additional risks that could increase the cost of borrowing, or alternatively, by identifying efficiencies that are obtained with centralized treasury operations at the holding company level for all of the utility's subsidiaries.

- The DLTDR shall not apply as a ceiling for external prudently incurred market-based debt for any utility.

The DLTDR will not be applied as a firm ceiling for utilities that have external market-based debt; however, the OEB will assess whether the cost of debt has been prudently incurred and consideration of the DLTDR will be part of that assessment. The OEB agrees with the OEA's submission that utilities should be able to recover their prudently incurred debt costs. Rate regulated utilities are expected to demonstrate that they have been prudent in their management of debt. The OEB will assess the processes the utility has in place to manage their treasury functions and how they have managed their debt. Utilities are required to file evidence to explain how they manage their long-term debt, including actual debt and the forecast for future debt.

[66] 2009 Report, pp. 53 & 54.

3.4.2 Long-Term Debt Transaction Costs (Issue 8)

Expert Report Proposals

LEI recommended that transaction costs be considered as operating expenses, as this approach is more suitable for the nature of the expense, which may fluctuate from year to year. LEI also noted the irregularity in frequency and amount of debt issuance. LEI stated that the utilities it reviewed record the transaction costs as interest expense, amortizing them using the effective interest rate method over the term of the related debt instrument.

Concentric, Nexus, and Dr. Cleary disagreed with LEI and stated that debt issuance costs are a legitimate cost of funding the operations of the utilities and should be recovered in rates through the embedded cost of long-term debt, as is the OEB's current practice.

In Concentric's experience, the common approach in North America to accounting for transaction costs is through the effective interest rate method. Concentric and Nexus suggested that LEI's approach puts Ontario utilities at risk of not recovering these costs. Concentric and Nexus raised further concerns that treating transaction costs as operating expenses may not be compliant with IFRS, with Concentric stating that this would cause a difference between regulatory reporting and financial reporting.

Submissions

Several ratepayer groups and OEB staff disagreed with LEI and submitted that the current approach of recording the actual transaction cost as an interest expense and amortizing the transaction cost over the term of the debt instrument (using the effective interest rate methodology) remains appropriate to be recovered in rates. CCC noted that this approach is reasonable as it is based on the actual debt-related transaction costs incurred by a utility (and amortizing over the term of the underlying debt instrument is logical as it matches the recovery of the cost with the term of the underlying debt). OEB staff was of the view that the current approach would mitigate any potential intergenerational inequity issues resulting from the mismatch of when the cost is recovered from customers at the time it is incurred, rather than over the life of the relevant financial instrument.

The OEA generally supported Concentric's proposals and stated that LEI does not present any compelling reason to deviate from the status quo.

CCMBC agreed with LEI that debt transaction costs should be included as an OM&A cost in the revenue requirement.

Findings

For utilities incurring transactions/issuance costs to secure financing from the market, the transaction/issuance costs should be incorporated into the debt interest rate used to set rates, so that the transaction costs are amortized over the term of the debt instrument using the effective interest rate methodology.

When a utility's holding company raises debt in the market on behalf of the utility, transaction/issuance costs are real costs incurred as part of that financing. In such cases, a pass-through of these costs by the utility is appropriate, as they are directly attributable to the utility's debt obligations and should be reflected in its overall cost of debt. In these circumstances, the OEB expects that transaction/issuance costs will be amortized over the term of the debt instrument using the effective interest rate methodology.

The OEB is not including transaction/issuance costs in the DLTDR, consistent with current practice. As noted previously, the DLTDR is used as a proxy for actual market-based long-term debt. The OEB expects that any associated legal costs from "papering" the debt between the utility and a municipal shareholder can be absorbed by the utility as part of its OM&A budget. While the DLTDR is a proxy for market-based long-term debt, it does not reflect the full cost structure of an actual debt issuance in the capital markets, making the inclusion of transaction costs unnecessary.

3.5 Short-Term Debt Rate

3.5.1 Approach to Short-Term Debt (Issue 4 and Issue 5)

Expert Report Proposals

LEI stated that the status quo DSTDR methodology which reflected a 3-month BA rate plus a spread is no longer appropriate. This is because major Canadian banks have transitioned all existing financial products that reference BA to referencing the Canadian Overnight Repo Rate Average (CORRA).

Concentric and Dr. Cleary agreed with LEI that for the DSTDR, the average of 3-month CORRA futures rates should be considered for the next 12-month period. LEI stated that this is more representative of investor expectations of short-term rates over the next year, in line with potential Bank of Canada policy rate reduction expectations.

To calculate the 2025 DSTDR, LEI recommended the use of:

- The futures rate for 2025 (average of implied rates for March, June, September, and December 2025) based on data as at September 30, 2024
- The spread for a R1-low rated utility over CORRA based on 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)

Dr. Cleary said he was fine with the above suggestions, but was also fine with using the existing CORRA rate as at September 30 of each year as the base CORRA rate. But Dr. Cleary noted that expanding the survey of banks should not lead to less reliable estimates (i.e., from the smaller banks), nor add unnecessary complexity to the survey process.

Submissions

OEB staff submitted that broadly speaking, to calculate the DSTDR, there are three alternatives to the BA rate: (1) the CORRA reference rate published by the Bank of Canada (or possibly a CORRA futures rate); (2) the Bloomberg ticker BVCAUA3M BVLI Index (3-month), which tracks utility bond yields; or (3) the three-month Canada T-bill rate.

OEB staff noted that a credit spread would need to be applied to (1) or (3) but not (2), which already has a credit spread built in. If (1) or (3) were selected, the spread could be based on a confidential survey of banks or a confidential survey of regulated utilities.

In OEB staff's view, any of these alternatives would be reasonable. However, OEB staff submitted that option (2), has the advantage of being administratively simpler as it would not require the OEB to calculate a spread by means of a bank or utility survey. More precisely, OEB staff submitted that the average of the trailing 12-months as at September 30 for the Bloomberg ticker BVCAUA3M BVLI Index (3-month) should be used to develop the DSTDR.

The OEA generally supported Concentric's proposals. The OEA also submitted that the proposal by OEB staff to use the Bloomberg 3-month BVCAUA3M BVLI Index was not appropriate. The OEA reasoned that it is a proprietary index that is only available to subscribers, and there is nothing on the record to indicate what data is actually behind this index. The OEA therefore submitted that the OEB should be wary of adopting a proprietary "black box" index which may be difficult to verify and access.

A number of ratepayer groups agreed with the proposals made by LEI, Concentric, and Dr. Cleary to use CORRA futures rates. However, CCC suggested that a different methodology to calculate the DSTDR should be used for 2025 rates versus 2026 and forward rates.[67]

VECC also supported Dr. Cleary's alternative proposal to use the existing CORRA rate as at September 30 of each year as the base CORRA rate. VECC concluded that either LEI's or Dr. Cleary's approaches would be reasonable.

Findings

The DSTDR for 2025 will be 3.91% on a final basis.[68]

The OEB will set a DSTDR each year starting with the 2025 rate year as part of this Decision. The DSTDR will be set using the September 30 data point sourced from the Bloomberg ticker BVCAUA3M BVLI Index (3-month) in each year. The approach of using the Bloomberg ticker was recommended by OEB staff for simplicity and only one party (OEA) made reply submissions on OEB staff's proposal. OEB staff does the calculation each year for the DSTDR, and the OEB finds their argument of simplicity persuasive. This simplicity is because it does not require a calculation of credit spreads through a bank or utility survey. The OEB has access to the index and OEB staff can access and issue the number each year.

As with the DLTDR, if an extraordinary change in market conditions occurs on or before September 30 and extends beyond that date, the OEB concludes that using the October 31 data point as an alternative is reasonable. This approach allows for sufficient time to assess whether market conditions have stabilized before determining the appropriate rate. Similar to the DLTDR, no specific trigger needs to be adopted for major events such as the 2008-2009 financial crisis or the COVID pandemic.

The formula for the DSTDR is:

$\mathrm{D}STDR_t = \mathrm{BVCAUA3M\ BVLI}_t$

[67] For 2025, use the average of 3-month CORRA futures rates for the next 12-month period plus a spread based on 2023 bank survey (adjusted by adding historical observed difference between 3-month CORRA and 3-month BA rates) to establish the DSTDR .
For 2026 and beyond, use the average of 3-month CORRA futures rates for the next 12-month period plus a spread based on the historical 12-month spread between Bloomberg BVCAUA3M BVLI Index and the 3-month CORRA.
[68] Bloomberg BVCAUA3M BVLI Index (3-month) rate – data point as at September 30, 2024.

Where:

> *BVCAUA3M BVLI$_t$* is the Bloomberg ticker BVCAUA3M BVLI Index (3-month) which tracks utility bond yields, with the data point as at September 30, taken from Bloomberg LP, for year t.

If at any point, the BVCAUA3M BVLI Index (3-month) becomes unavailable in its current form, the OEB concludes that it is reasonable to calculate the DSTDR (and as an alternative to the prescribed interest rate for DVAs) using the actual CORRA reference rate as at September 30. Applied to this would be an average estimate of the spread for short-term 3-month loans over the CORRA for R1-low or A (A-stable) commercial utility customers based on an annual confidential survey of at least three Canadian banks, with no outliers used.

3.5.2 Rate and Applicability (Issue 4 and Issue 5)

Expert Report Proposals

Regarding the application of the DSTDR to different utilities, LEI noted that:

- 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). In rate applications, natural gas distributors and OPG provide forecasts of short-term debt rates based on their actual debt portfolio.

LEI recommended that the DSTDR should be applied as a cap for all utilities. Concentric disagreed with LEI regarding the application of a cap, as actual costs of borrowing can deviate from the DSTDR for reasons that are outside of the control of the utility. Concentric noted that the cap would be extended to Enbridge Gas and OPG under LEI's proposal. Concentric supported the continued use of the forecasted rates by the utilities, as in its view, this would allow the utilities, in circumstances where their cost of debt is expected to exceed the cap, to demonstrate why their utility-specific debt cost is reasonable. Concentric stated that for natural gas distributors and OPG, the applicant forecasts its own cost of short-term debt for the test year.

Dr. Cleary stated that the current approach is reasonable in principle.

Submissions

OEB staff and CME agreed with LEI that the DSTDR should be applied as a cap for all utilities (and not just electricity distributors and transmitters). OEB staff noted that OEB-regulated entities have similar credit ratings and that this may potentially incentivize utilities to improve their credit profile and/or negotiate better borrowing terms, if their actual rates are higher than the DSTDR. The OEA disagreed, stating that in practice short-term debt costs are set by commercial paper market prices, which means they are effectively set through an auction.

OEB staff agreed with LEI that the DSTDR should be applicable as a cap for the unfunded portion after deducting from the long-term debt and common equity portions for Enbridge Gas and OPG. OEB staff was of the view that this is not practical to implement for the other Ontario utilities and there should be no true-up between the deemed and actual capital structure for such utilities. This issue is discussed in more detail in Section 3.3 of this Decision.

The OEA generally supported Concentric’s proposals and also disagreed with LEI’s recommendation to apply a cap on the short-term debt rate for all utilities, stating that the previous model had worked well, and LEI was unable to identify any actual harm its approach tries to mitigate. The OEA stated that the rote application of a cap could result in utilities not being provided with the opportunity to recover prudently incurred costs.

CME submitted that the OEB should apply the DSTDR methodology as a soft cap for Enbridge Gas and OPG, but which can be rebutted by evidence from the utility.

CCC stated that the OEB should continue its approach of using actual short-term debt costs for Enbridge Gas and OPG (and updated only at rebasing). CCC submitted that these utilities should be allowed to apply for a different approach to short-term debt if they believe that is appropriate.

Findings

The DSTDR will continue to apply to all electricity distributors and transmitters, as well as EPCOR Natural Gas (Aylmer and South Bruce), rebasing rates in 2025 and beyond, unless some other approach was previously approved by the OEB.

For OPG and Enbridge Gas, the DSTDR will not be applied as a cap on the unfunded portion of the capital structure (the portion of the capital structure to reach 100%). The OEB will assess whether the cost of debt has been prudently incurred, and the DSTDR will be considered as part of that assessment. OPG and Enbridge Gas are expected to demonstrate that they have been prudent in their debt management. In determining that prudence, the OEB will assess the management of debt and the processes the utility has in place to manage their treasury functions. OPG and Enbridge Gas are required to file evidence to explain how they manage their short-term debt.

3.6 Implementation of the Cost of Capital Framework

3.6.1 Monitoring (Issue 14 and Issue 15)

Expert Report Proposals

Specific Items Monitored

LEI stated that 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. Dr. Cleary and Nexus also agreed on the preparation of quarterly reports.

Concentric did not object to a quarterly report, but was of the view that an annual update was sufficient and also did not see any basis for restricting the monitoring to an internal report. Nexus did not object to a quarterly report, but had a view similar to Concentric that it should be made available to all interested parties.

In addition, LEI and Dr. Cleary recommended that 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 placements and equity issuances during the year. LEI noted that utilities should also provide 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.

In LEI's view, the OEB could use this information to monitor the credit ratings and pace of capital injections for the regulated utilities on an ongoing basis, as a further test of whether the FRS continues to be met. LEI did not expect these additional reporting requirements to introduce a significant regulatory burden for utilities.

Concentric did not support LEI's recommendation to modify annual reporting to include results of recent credit and equity issuances, as this information would be retrospective for the prior year, would be administratively burdensome, and beyond typical reporting requirements. Nexus noted that this LEI recommendation avoids the fundamental question about compliance with the FRS – does the ROE provided to Ontario distributors offer a return equal to investments of comparable risk.

Instead, Concentric recommended that the OEB track and compare the following key utility and broader macroeconomic parameters on an annual basis:

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

Nexus suggested that the deemed ROEs provided in Ontario be compared to peer jurisdictions similar to the benchmarking analysis Nexus provides in its report.[69] The OEB should include a benchmarking analysis of ROEs in addition to the existing processes.

Confirmation of Meeting the FRS

LEI, Concentric, and Dr. Cleary stated that the OEB should continue to annually confirm that the FRS is being met.

Concentric stated that periodic rate hearings remain the only reliable method for determination of utility ROEs that remain consistent with the FRS. Concentric further stated that its monitoring recommendations should be sufficient to detect any material deviations from the FRS over the period between full reviews (e.g., every five years).

Concentric further recommended that the 300-basis point trigger mechanism policy for all rate-regulated utilities be continued, in conjunction with earnings-sharing mechanisms.

[69] Chapter III Benchmarking of ROEs to Comparable Jurisdictions

Submissions

Specific Items Monitored

OEB staff agreed with LEI and Dr. Cleary that consistent with the OEB's existing policy, the OEB should continue to monitor the cost of capital parameters and test their reasonableness in the context of prevailing macroeconomic conditions through the generation of a report. However, OEB staff noted that these reports should only be prepared annually (instead of quarterly as recommended by LEI, Nexus, and a number of ratepayer groups), as well as maintained as an internal OEB document.

While the OEA did not object to a quarterly report being prepared, it was of the view that annual updates were sufficient but should be made public. A number of ratepayer groups also agreed that these reports should be made public.

OEB staff's view was that, while there may be some value in annually gathering the information proposed by LEI, it would not justify the added regulatory burden on utilities. OEB staff recommended that additional reporting be constrained to those things for which the review process is specified, and the eventual use of that reporting item or report is clear. This principled approach to additional reporting maintains the balance between regulatory burden and the OEB's monitoring function.

A number of ratepayer groups agreed with LEI that monitoring should also include a review of actual debt and equity issuances by Ontario utilities. The OEA recommended rejecting this proposal, as there is insufficient evidence to support the need for this type of information and it would lead to an increased level of administrative burden. SEC argued that LEI's proposed reporting requirements are not administratively burdensome, especially when considering the overall cost to customers of a utility's cost of capital. SEC also noted that the debt information is essential for the OEB to compare the DSTDR and DLTDR with actual borrowing rates, while the equity data allows for monitoring of the need for equity capital and the costs associated with raising it. VECC saw some merit in the OEB obtaining such information as input into the reasonableness of its calculated DSTDR and DLTDR for the coming year.

The OEA recommended the OEB annually track and compare certain key utility and broader macroeconomic parameters, as noted in Concentric's expert report.

The OEA did not oppose Nexus' suggestion that the OEB complete a benchmarking exercise of Ontario's utilities to its peer jurisdictions to confirm that the FRS is met, but the OEA also believed Concentric's recommendations were sufficient.

VECC and CCMBC agreed with LEI, Concentric, and Dr. Cleary that utilities should be directed to provide any recent credit rating reports. VECC stated that this information would assist the OEB in assessing the financial integrity component of the FRS. OEB staff disagreed with providing credit rating reports.

Confirmation of Meeting the FRS

OEB staff and some ratepayer groups agreed with LEI and Dr. Cleary that ongoing monitoring of the cost of capital parameters enables the OEB to confirm the FRS continues to be met between comprehensive reviews of those parameters. OEB staff and the OEA agreed with Concentric that periodic generic rate hearings remain the only reliable method for determination of utility ROEs that remain consistent with the FRS.

Findings

The OEB will continue to monitor market conditions. It is expected that OEB staff will undertake this monitoring at least quarterly and will report internally on their assessment. This monitoring will include quarter-over-quarter and year-over-year comparisons of each element of the formulas for the DSTDR, DLTDR and ROE, a scan of ROEs approved by energy regulators in Canada, and updated credit ratings for Ontario utilities. Each year, when the OEB issues the updated cost of capital parameters, an overall assessment from this monitoring will be provided externally. This will include the OEB's conclusion on whether the cost of capital parameters updated through the formulae are reasonable and the FRS continues to be met.

The OEB agrees with Concentric that reporting of all debt issuances (short-term and long-term) would be administratively burdensome[70] without commensurate benefit. However, the OEB concludes that information on major long-term debt issuances by Ontario utilities would be helpful. Therefore, the OEB is requiring any rate-regulated utility that issues new long-term debt in excess of $50 million (whether directly or through an affiliate) to report this to the OEB once a year (by April 30 for debt issued in the prior calendar year), including quantity, term, and interest rate. The OEB concludes that these actual debt issuances would be useful as a check against the reasonableness of the DLTDR and valuable information on the state of the financial markets. The report must be sent to the OEB's performance reporting email address (performance_reporting@oeb.ca) and to the Registrar.

[70] Transcript Volume 3, pp. 168-170

The OEB expects that credit ratings for utilities will be available publicly and therefore is not requiring utilities to report this outside of a rebasing rate application. As noted by OEB staff, if the OEB has concerns about changing market conditions, it can always introduce reporting requirements or monitor additional elements (such as betas or bond yields) on an ad hoc basis to assist in assessing the impact of any changes.

3.6.2 Update to Cost of Capital Parameters (Issue 16)

Expert Report Proposals

Consistent with the OEB's existing policy, LEI stated that the OEB should continue to publish its annual cost of capital parameter updates in October or November, but 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) rather than 30-day data, for rates going into effect in the following January or May.

Concentric agreed with LEI, but recommended trailing 90-day averages where historical data are utilized, as opposed to 12-month trailing as recommended by LEI. Dr. Cleary recommended maintaining the status quo but considered changing to the use of October data rather than September data to update the annual ROE adjustment formula, if the OEB determined this change would not cause undue disruptions to its existing processes and procedures.

LEI noted that stakeholders are familiar with the OEB's existing cost of capital update schedule, and so continuing this approach would promote predictability and stability objectives.

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

Submissions

OEB staff agreed with LEI's proposal.

The OEA recommended the OEB should continue to update its cost of capital parameters in October, using data as of September 30, except where forecasts are utilized and recommended trailing 90-day averages where historical data are utilized.

CCMBC agreed with Dr. Cleary that the OEB maintain the status quo but considered changing to the use of October data rather than September data to update the annual ROE adjustment formula.

CCC and Pollution Probe submitted that the annual cost of capital parameter updates should occur at around the same time of the year as they do currently (i.e., late October).

Findings

As described under relevant issues above, the ROE, DLTDR, and DSTDR will be updated annually using data as at September 30. The OEB will issue a letter each year in the Fall with the updated cost of capital parameters for rates effective in the following rate year.

As discussed in Sections 3.2, 3.4 and 3.5 of this Decision for the ROE, DLTDR, and DSTDR, respectively, if an extraordinary change in market conditions occurs on or before September 30 and extends beyond that date, the OEB concludes that using the October 31 data points as an alternative is reasonable. This approach allows for sufficient time to assess whether market conditions have stabilized before determining the appropriate rates.

Before finalizing the cost of capital parameters for each year, the OEB will assess each value and the relationships between them in the context of the market monitoring information. The OEB will make a determination on whether the numerical results from the formulaic methodologies meet the FRS before issuing the final parameters each year.

3.6.3 Term of the New Cost of Capital Framework (Issue 17)

Expert Report Proposals

LEI and Concentric recommended that consistent with the OEB’s existing policy, the OEB should commit to reviewing the cost of capital policy every five years. Nexus recommended that the OEB limit LEI’s proposed annual ROE adjustment formula to two years and then review the cost of capital parameters again in an open forum such as this in the third year. Dr. Cleary supported reviews of the cost of capital policy at regular intervals (ideally every three years, but never more than five years).

LEI was of the view that the OEB should maintain the existing trigger mechanisms, including allowing utilities to apply for different cost of capital parameters during their individual rate hearings, as well as having a regulatory review potentially triggered through the off-ramp mechanism (which may or may not include a review of the cost of capital parameters) and/or capital structure.

Similarly, Concentric proposed to adopt the “FERC approach”, allowing the OEB or an intervenor to challenge the reasonableness of the allowed return (including both the ROE and capital structure), or for a company to request a change in its authorized return, based on updated market evidence. Dr. Cleary echoed this, noting that under the OEB’s current practice an applicant or intervenors can file evidence in individual rate hearings in support of different cost of capital parameters due to their specific circumstances.

LEI further noted that a longer interval between comprehensive reviews would reduce administration costs, however, the cost of capital policy should be reviewed with enough frequency to ensure alignment with prevailing macroeconomic conditions.

Nexus stated that increasing the frequency of a litigated proceeding to every three years would provide the following advantages: it would (i) maintain the ROE at a rate dictated by financial markets; (ii) establish a level of institutional knowledge; and (iii) address uncertainty about energy policy and the impact of energy policy on cost of capital issues.

Dr. Cleary noted that the existing OEB trigger mechanisms and procedures that are in place are reasonable and should be retained, but had one suggestion for a specific trigger mechanism. Dr. Cleary recommended that if the Canadian A-rated utility yield spreads exceed 2%, the OEB should undertake an immediate and thorough assessment of existing capital market conditions, which could potentially lead to a full regulatory review, depending on the results of this assessment.

Dr. Cleary also noted that the OEB has off-ramp mechanisms in place, which can trigger regulatory reviews if earnings fall outside a wide band which seemed reasonable and pragmatic to Dr. Cleary.

Submissions

OEB staff agreed with LEI and Concentric that the OEB should commit to reviewing the cost of capital policy every five years. OEB staff submitted that this issue is about balance and weighing the costs of performing an update of the cost of capital policy against the benefits of incorporating more up-to-date capital market information and analysis.

The EDA stated that the deemed ROE should be rigorously updated every three years, so that it does not get out of alignment with market conditions, which in the EDA's view, it did in the long interval since the OEB's 2009 Report.

The OEA noted that there was virtual consensus amongst the parties who commented on this issue that the OEB should implement a policy of holding a full cost of capital review every five years. The OEA stated that Dr. Cleary's specific 2% approach seems to be unnecessary if the OEB commits to full cost of capital and capital structure reviews every five years.

A number of ratepayer groups stated that a cost of capital policy review should be conducted every five years. CME submitted that the OEB should retain the status quo regarding trigger mechanisms. CCC stated that the cost of capital for Enbridge Gas and OPG should be established in their next rebasing proceedings.

CCMBC agreed with Dr. Cleary that the OEB should have reviews of the cost of capital policy at regular intervals (ideally every three years, but never more than five years). CCMBC submitted that the OEB should retain the status quo regarding trigger mechanisms, but CCMBC and VECC also supported Dr. Cleary's 2% approach.

Pollution Probe recommended that the OEB use a rolling 10-year review period for a scheduled review of the cost of capital methodology, with the appropriate ability for interim action if warranted. Pollution Probe stated that based on that cycle, the OEB could test whether an extensive review is required. Reviewing too often would be trying to solve a problem that does not exist. In Pollution Probe's view, there is no need to add a specific trigger mechanism for a review.

VECC argued that the type and depth of analysis underpinning the Staff Report aligns with what the OEB should be undertaking annually in order to confirm the continuing appropriateness of its cost of capital parameters. In VECC's submission the only real mechanisms that exist for triggering reviews of the OEB's cost of capital policy are the OEB's quarterly and annual reviews.

Findings

The term of the new Cost of Capital Framework is five years. On that basis, the next review is expected to conclude in 2030, with the depth and breadth expected to be similar to the current exercise. Most parties agreed with this term, though some encouraged a shorter period of three years given energy transition issues. The OEB expects that within five years there will be greater understanding of the pace of energy transition. Furthermore, there are other regulatory instruments at the disposal of utilities such as off-ramp mechanisms, DVAs, z-factors, and incremental capital modules, should a need arise for utilities to seek cost recovery from unexpected and required investments. The OEB is also working on a number of initiatives, such as performance incentive mechanisms, that should conclude within the five-year period.

The OEB always has the ability to initiate a review sooner if it concludes that there have been significant changes in the markets affecting utilities, as it did for the financial crisis of 2008. In addition to the formulaic approach, an applicant or intervenors can file evidence in individual rate hearings to support different cost of capital parameters due to their specific circumstances. This evidence must provide a strong rationale for departing from the OEB's policy and why the FRS cannot be met. This is a continuation of the approach explained by the OEB in its October 31 letter.[71] Any applicants intending to file an application for an amended cost of capital are strongly encouraged to hold a stakeholder session in advance of filing an application to explain their planned approach for the parameters.

As determined above, the OEB will monitor market conditions. As discussed in Section 3.2.3, the OEB concludes that no precise trigger mechanism is required to initiate an earlier review of cost of capital.

3.6.4 Implementing the New Cost of Capital Framework (Issue 18 and Issue 19)

Expert Report Proposals

LEI stated that 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. Dr. Cleary also agreed with the status quo, but subject to any concerns regarding mitigation of significant resulting rate impacts.

LEI noted that the OEB reviews the capital structure only upon an application from the utility or other participants, generally during the review of a rebasing rate application. LEI stated that 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.

[71] OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024.

LEI stated that to ensure the FRS continues to be met, the OEB should also introduce an option for parties to request implementation of changes to cost of capital parameters and capital structure prior to rebasing, so long as a 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 basis points or more). Dr. Cleary agreed with this two-factor test.

Concentric saw no basis for a two-factor test or a determination of “rate shock” as described by LEI. It recommended that changes in the cost of capital parameters and/or capital structure should take effect for all utilities in the rate year following the OEB’s decision in this proceeding, and in subsequent periods where the parameters are updated. In Concentric’s view, it is not necessary to wait for rebasing, and any delays in implementation would not serve the public interest or meet the FRS, if the OEB determines that updated parameters are justified. However, Concentric stated that depending on the magnitude of change in the deemed capital structure, the OEB may want to consider changes in capital structure implemented over a period of up to three years.

Submissions

OEB staff and a number of ratepayer groups agreed with LEI and Dr. Cleary that 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. Given that OEB staff’s recommendations for setting the ROE (Issue #10) and capital structure (Issue #12) would not result in a significant change from the status quo, OEB staff found no reason why any such changes could not wait until rebasing to be implemented.

OEB staff and a number of ratepayer groups submitted that the revised cost of capital policy should apply to all utilities filing cost-based applications for 2025 and forward rates, but with some exceptions.[72]

The OEB established generic variance accounts for utilities rebasing rates in 2025 before the issuance of this Decision. SEC and VECC recommended that the OEB require those utilities to update their base rates for the new cost of capital parameters as part of their next rate adjustment process to avoid significant balances (credits or debits) accumulating in the variance accounts and to minimize intergenerational equity.

[72] There are a few cases for 2025 rates that have been concurrent with this generic proceeding wherein parties have reached a settlement agreement on cost of capital matters and implementation.

The OEA generally agreed with Concentric's proposals to implement changes in the next rate year.

OEB staff noted that most parties recommended that any changes resulting from this proceeding be implemented for each regulated utility at the time of rebasing.
In response to Concentric's recommendation that changes in the cost of capital parameters should take effect for all utilities in the rate year following the OEB's decision in this proceeding (and in subsequent periods where the parameters are updated), CCC noted practical matters. CCC stated that determining the appropriate change to rates to reflect a change to the cost of capital in the middle of a Price Cap incentive rate-setting mechanism (IRM) term is difficult. CCC and SEC further suggested that to allow for changes to base rates (and resulting changes to the bill impacts) that the OEB already determined were just and reasonable after they were established is not appropriate.

SEC agreed with VECC, that during an IR term or rate plan, "there are likely to be changes to a number of the utility's cost components, with cost of capital only being one of them," and that it should not "be treated any differently than changes in other cost components of the revenue".

Findings

The cost of capital parameters of ROE, DSTDR, and DLTDR are applicable to utilities rebasing rates for 2025 (if cost of capital is in scope). For other utilities, the new cost of capital parameters will be implemented on a one-time basis at the utility's next rebasing rate application. As discussed in Section 3.1 of this Decision, the OEB has concluded that the FRS is being met with the current 2009 Cost of Capital Framework. For this reason, the OEB concludes that implementing the new Cost of Capital Framework at the same time that the OEB is reviewing other costs of service is appropriate. Updating one type of cost of service (cost of capital) in isolation from the other costs in the revenue requirement (OM&A, depreciation, taxes, etc.) should only be considered if there is compelling evidence that the FRS is not being met. Furthermore, as discussed in Section 3.6 of this Decision, the OEB will annually monitor market conditions and the updated cost of capital parameters to determine whether the FRS continues to be met.

Nevertheless, if a previous decision of the OEB states that the final cost of capital parameters to be established in this generic proceeding for 2025 will be adopted by a utility prior to the utility's next rebasing rate application, that decision prevails. It is not this panel's intention to disturb prior approvals.

Utilities that implemented rates in 2025 using interim cost of capital parameters were granted variance accounts to record the difference between the revenue requirement at interim and final cost of capital parameters. The OEB will consider the disposition of these balances in both IRM and Custom IR update rate applications. The OEB will also consider applications to amend base rates to reflect any changes in revenue requirement for 2025, but only if there was no specific treatment previously approved by the OEB for the 2025 rate application. This approach will allow the variance accounts for 2025 to be disposed and closed.

Any adjustment to base rates should use only data from the final approved revenue requirement calculation and billing determinants (no updated forecast).

If a utility receives rebasing approval after this generic decision, but is unable to implement by the date of its effective rates, then the utility will be permitted to use the interim cost of capital parameters and associated variance accounts.

The prescribed interest rates for DVAs and CWIP for October 1, 2024 and January 1, 2025 were issued on a final basis so there is no true-up required. The new prescribed interest rates for DVAs and CWIP are therefore effective April 1, 2025 and will be updated quarterly.

3.7 Prescribed Interest Rates

3.7.1 Deferral and Variance Accounts (Issue 20 and Issue 21)

Expert Report Proposals

LEI noted that the current methodology for DVAs is no longer appropriate, due to the winding down of the 3-month BA rate, as explained in Section 3.5 of this Decision.

For DVAs, LEI recommended aligning the prescribed interest rate with the revised calculation methodology recommended by LEI for the DSTDR, namely:

- For the reference rate, the average of 3-month CORRA futures rates for the next 12-month period should be determined
- 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)

Dr. Cleary agreed with LEI's recommendations. Concentric agreed with LEI's recommendation for short-term DVAs (i.e., accounts that will be disposed within one year), but recommended the OEB apply each utility's WACC to long-term DVAs (i.e., DVAs that remain on utilities' balance sheets for more than one year). In Concentric's view, the appropriate carrying cost on DVAs should reflect the cost of capital associated with the delay in recovery.

Concentric further stated that the principle of a fair return applies to DVAs because utilities have committed capital to fund their deferred costs, and that commitment of capital warrants the opportunity to earn a reasonable return. Concentric noted that for utilities to have the opportunity to earn a reasonable return, they must have the opportunity to recover the WACC. Concentric stated that the application of the WACC to long-term DVAs would be consistent with the BCUC's approach.

Submissions

OEB staff submitted that the OEB's current practice of reviewing the prescribed interest rates for DVAs quarterly should be maintained, with updates only if the formulaic approach results in a change in interest rates of 25 basis points or more.

OEB staff also submitted that the prescribed interest rates applicable to DVAs should reflect the respective data point at the end of the month that is one month prior to the start of the quarter (e.g., a November 30 data point for the quarter starting January 1).

OEB staff submitted that for the prescribed interest rate for all DVAs, the Bloomberg ticker BVCAUA3M BVLI Index (3-month) should be used, consistent with the DSTDR in Section 3.5 of this Decision.

OEB staff submitted that broadly speaking, to calculate the prescribed interest rates for DVAs, there are three alternatives to the BA rate:

(1) the CORRA reference rate published by the Bank of Canada (or possibly a CORRA futures rate)
(2) the Bloomberg ticker BVCAUA3M BVLI Index (3-month), which tracks utility bond yields
(3) the three-month Canada T-bill rate

OEB staff noted that a credit spread would need to be applied to (1) or (3) but not (2), which already has a credit spread built in. If (1) or (3) were selected, the spread could be based on a confidential survey of banks or a confidential survey of regulated utilities.

Further to the details noted in Concentric's expert report (i.e., the rates applicable to short-term DVAs and long-term DVAs), OEB staff noted that an additional alternative methodology was suggested by Concentric, which was to apply the prescribed interest rate for DVAs to Group 1 DVAs and the WACC to Group 2 DVAs.[73]

In OEB staff's view, any of these alternatives would be reasonable, except for Concentric's recommendation about using different rates for Group 1 and Group 2 DVAs. However, OEB staff submitted that option (2) has the advantage of being administratively simpler.

OEB staff disagreed with Concentric that a WACC rate should be applied to the OEB's Group 2 DVAs. OEB staff argued that:

- If the DVA records operating expenses, but if the WACC were to apply, the utility would in effect be making a ROE on a portion of the amounts, even though there is no equity.
- If the DVA records 100% capital, the revenue requirement impact is recorded in that DVA (and not the gross amount of the capital spend), but the revenue requirement impact already reflects the WACC and another WACC should not be layered onto the principal balance.

The OEA generally supported Concentric's proposals and clarified that the WACC on long-term DVAs should be the WACC approved in the most recent rate proceeding for each utility.

SEC and CCC disagreed with Concentric's proposal that long-term DVA accounts should attract a return using WACC, with SEC noting that nearly all DVA balances would be subject to a WACC. SEC and CCC suggested that the OEB may be deterred from approving new DVA accounts and CCC suggested that there would be a "perverse incentive" for utilities to seek to record operating costs in DVAs.

In reply, the OEA disagreed with SEC and CCC and submitted that in addition to ignoring that the financing cost would be symmetrically applied to both debit and credit DVA balances, these are inappropriate arguments. The OEA reasoned that the setting

[73] The OEB's EB-2008-0046 *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)*, July 31, 2009, addressed Group 1 DVAs and Group 2 DVAs. This report stated that the OEB's two groupings (i.e. Group 1 and Group 2) are based on the required depth of the OEB's review and the process in which the account balances would be reviewed. Group 1 DVAs include accounts that do not require a prudence review, while Group 2 DVAs include accounts that do require such a review.

of rates is subject to the just and reasonable standard and the OEB considers the relative merits for each DVA proposal. The OEA claimed that "none of this would be affected by using a more representative carrying cost for the DVAs."

SEC and CCC also claimed that there would be some loss of regulatory efficiency with the Concentric approach because Group 2 accounts may need to be disposed on an annual basis. SEC also expressed additional concerns that:

- It would be inequitable for Group 1 accounts to attract a WACC carrying cost because these accounts carry virtually no risk and similarly, Group 2 accounts have minimal risk of disallowance.
- There is no evidence that DVA balances are funded through long-term debt and equity.

In reply, the OEA stated that these arguments made by SEC and CCC misconstrue the basis for the OEA's recommendation. The OEA's recommendation is rooted in the recognition that, just like its assets, a utility's financing resources comprise a mix of shorter- and longer-term funding and is also not based on the level of risk associated with a particular DVA.

A number of ratepayer groups agreed with LEI's proposal for the prescribed interest rate on DVAs. However, as noted in Section 3.5 of this Decision, CCC suggested that different methodologies to calculate the DSTDR should be used and submitted that with respect to the calculation of the prescribed interest for DVAs, the OEB should apply the same approach as that for the DSTDR.

Findings

The OEB will apply the same approach for determining the prescribed interest rate for DVAs that it has established for the DSTDR, for the same reasons provided under that issue. This approach is to use the Bloomberg ticker BVCAUA3M BVLI Index (3-month). As with the DSTDR, the CORRA reference rate with a credit spread based on a confidential survey of banks could be used as a backup if necessary.

The prescribed interest rate for DVAs effective April 1, 2025 for Q2 2025 is 3.16%, on a final basis, reflecting the data point as at February 28, 2025.[74]

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[74] The prescribed interest rate from Q1 2025 was 3.64%, as per the OEB's Prescribed Interest Rates website. The updated rate of 3.16% for Q2 2025 reflects the data point as at February 28, 2025, resulting

Additionally, the OEB will continue its current practice of setting the prescribed interest rates applicable to DVAs quarterly. These rates will only be updated if the formulaic approach results in a change in interest rates of 25 basis points or more. Otherwise, the previous quarter's prescribed interest rate will be maintained for the following quarter.

The prescribed interest rates applicable to DVAs shall continue to reflect the respective data point at the end of the month that is one month prior to the start of the quarter (e.g., a November 30 data point for the quarter starting January 1). These rates will be published on the OEB's website shortly thereafter, effective for the next quarter (e.g., January 1 to March 31).

The OEB is not persuaded by Concentric's argument that the principle of a fair return applies because utilities have committed capital to fund their deferred costs. The OEB notes that utility rates already compensate for the cost of financing working capital. Therefore, if a long-term rate were applied to DVAs, it would effectively double-compensate utilities, since they are already allowed to recover their working capital through base rates. Moreover, Concentric does not link the level of risk associated with a DVA to the proposed interest rate, which contradicts the risk-based rationale underlying the FRS. Applying a long-term rate such as the WACC would increase costs to ratepayers, even when utilities face little risk in recovering prudently incurred DVA balances. There was also no evidence presented that DVAs are funded through long-term debt and equity.

DVAs are a regulatory tool that should be used only in essential circumstances to allow costs to be accounted before they can be recovered through rates, in a manner that does not result in rate retroactivity. For DVAs involving OM&A expenses, the OEB concludes that a utility should not earn a return on deferring recovery of OM&A expenses, as would occur if the interest rate was the WACC. Applying a WACC would actually incent utilities to seek more DVAs, and DVAs should only be used when absolutely necessary. Furthermore, for DVAs involving capital expenditures, the amount recorded in the DVA is typically the revenue requirement for the expenditure, which is based on the return on the investment (debt and equity) using the WACC. The OEB disagrees that an interest rate of the WACC should apply on the amount in the DVA that was already calculated using the WACC.

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in a change in interest rates of 48 basis points.

If the DVA involves long-term expenditures, a utility can propose a different carrying charge as part of a cost-based rate application (or standalone accounting order application), with evidence to justify the departure from standard practice.

3.7.2 Construction Work in Progress (Issue 20 and Issue 21)

Expert Report Proposals

For CWIP, LEI recommended (and Dr. Cleary agreed) 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 recommended continuing the current CWIP accounting procedures as set out in the Accounting Procedures Handbook (APH).

Concentric disagreed with LEI's recommendation regarding CWIP. Concentric recommended that the WACC be applied in order to provide for recovery of the utility's full financing cost (including the cost of equity), particularly given the need to attract significant capital in support of the energy transition. Concentric suggested that from an implementation perspective, this approach would not be burdensome to utilities.

Concentric stated that the current approach that applies the long-term cost of debt to CWIP balances has the potential to significantly understate the cost of capital for utilities during the construction phase of projects, as many are larger and long-term. Over those periods, the utilities are financing construction on their balance sheets at the WACC, which includes an equity component.

Concentric further stated that a long-term debt-only approach also places Ontario utilities out of step with their U.S. and Canadian peers, placing them at a relative disadvantage in the ability to attract equity capital.

Submissions

OEB staff submitted that the OEB's current practice of reviewing the prescribed interest rates for the CWIP account quarterly should be maintained, with updates only made if the formulaic approach results in a change in interest rates of 25 basis points or more.

OEB staff also submitted that the prescribed interest rates applicable to the CWIP account should reflect the respective data point at the end of the month that is one month prior to the start of the quarter (e.g., a November 30 data point for the quarter starting January 1).

OEB staff agreed with LEI and Dr. Cleary that for the prescribed interest rate for CWIP a debt-based rate should be used, as per the status quo, specifically the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate yield.

OEB staff stated that the status quo CWIP rate should continue to be applied to all projects under construction, regardless of the construction period. OEB staff also agreed with LEI's recommendation to continue the current CWIP accounting procedures as set out in the APH.[75] OEB staff submitted that if a utility is not using the OEB's prescribed interest rate for CWIP and uses its own actual borrowing rate in the situations allowed in the APH, it should use a debt-based rate, as opposed to a WACC.

OEB staff noted that in Ontario, CWIP is not included in rate base. If a utility were to apply the WACC to CWIP, CWIP would be treated the same as capital additions to rate base, even though the asset under construction is not yet used and useful.

In the oral hearing, TFG/Minogi raised concerns that the current approach for the prescribed interest rate for CWIP effectively blocks most First Nations from investing in regulated assets during construction.[76] That is because most First Nations must borrow funds at a cost that is often higher than the prescribed interest rate for CWIP and equity capital is often employed in construction.[77] TFG/Minogi suggested that applying the WACC to CWIP would overcome the immediate shortfall position. TFG/Minogi echoed these concerns in its submission.

OEB staff submitted that instead of the OEB approving a WACC to CWIP on a generic basis, utilities with large multi-year capital projects should continue to be able to apply for a project-specific ROE to be included in CWIP, as per the current OEB policy set out in the Infrastructure Investment Report.

In the oral hearing, TFG/Minogi also raised concerns that investors do not receive payment during the construction phase and must wait until a new facility is in service before they can receive payment.[78] TFG/Minogi argued that the OEB could also consider adopting an approach of concurrent cost recovery (CCR) for these projects, at least with respect to First Nations' equity investment.[79] TFG/Minogi echoed these concerns in its submission, requesting that the OEB confirm:

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75 Accounting Procedures Handbook For Electricity Distributors, Issued: December 2011, Effective: January 1, 2012, Article 220, p. 200; Article 410, pp. 27 & 28.
76 Transcript Volume 1, pp. 7 & 8.
77 Transcript Volume 1, p. 16.
78 Transcript Volume 1, p. 16.
79 Transcript Volume 1, p. 19.

i. The availability of CCR in large, multi-year projects, subject to application to the OEB in the specific circumstances of the case; and
ii. That CCR will be made available in circumstances where doing so will mitigate obstacles to investment involving cost for an Indigenous applicant.

TFG/Minogi also referenced the Infrastructure Investment Report in its submission, specifically the availability of accelerated cost recovery mechanisms applicable to CWIP and pre-commercial expenses.

CFN/MCFN generally supported and adopted TFG/Minogi's submissions.

OEB staff was of the view that TFG/Minogi's recommended approach of CCR for its projects is outside of the scope of this proceeding and any unique First Nations issues can be addressed in a rate application by a First Nations owned utility. OEB staff noted that the panel of Commissioners confirmed that the CCR matter is out of scope in its letter approving the late intervention of the First Nations intervenors.

The OEA generally supported Concentric's proposals and clarified that the WACC on CWIP should be the WACC approved in the most recent rate proceeding for each utility. In its reply, the OEA disagreed with arguments made by OEB staff and some ratepayer groups that a WACC return on CWIP would violate the used and useful test. The OEA stated that investments placed in rate base would remain subject to the used and useful test, but it is the cost of financing those investments prior to placing them in rate base which is at issue.

The OEA also disagreed with arguments made by CME and SEC that utilities use only or predominantly short-term financing, or construction loans, to finance their investments. The OEA further disagreed with arguments made by SEC and CCC that the application of the WACC to CWIP balances would provide a "double" return on the utilities' invested capital. In the OEA's view, this argument ignores the fundamental rate of return principle that allows a utility to recover the prudently incurred costs of its investments, including its financing costs.

A number of ratepayer groups agreed with LEI's proposal for the prescribed interest rate on CWIP.

CCC submitted that none of the three proposals requested by TFG/Minogi should be accepted on a generic basis applicable to all rate-regulated infrastructure projects, namely the adoption of: (1) a risk premium for single-asset transmitters (as discussed further in Section 3.3 of this Decision); (2) a WACC applied to CWIP; or (3) CCR. CCC stated that these proposals go beyond setting generic cost of capital parameters for Ontario's utilities and instead reflect important policy questions that require careful consideration. SEC noted that the OEB should convene a dedicated process to look at regulatory, jurisdictional, and fairness issues that may arise, with both SEC and CCC referencing a separate generic proceeding or consultation. SEC and CCC suggested that utilities or project proponents considering Indigenous ownership can request deviations from the existing policy in rates or leave to construct applications.

Findings

The OEB will continue to use the FTSE Canada Mid Term Bond Index All Corporate yield as the prescribed interest rate for CWIP. The OEB finds it reasonable to use a mid-term index for CWIP that will be added to rate base at the next rebasing rate application for assets in service, with the WACC being applied to rate base. The prescribed interest rate for CWIP effective April 1, 2025 for Q2 2025 is 4.23%, on a final basis.

Similar to DVAs, the OEB will continue its current practice of setting the prescribed interest rates applicable to the CWIP account quarterly. These rates will only be updated if the formulaic approach results in a change in interest rates of 25 basis points or more. Otherwise, the previous quarter's prescribed interest rate will be maintained for the following quarter. For Q2 2025, the prescribed interest rate from Q1 2025 is being maintained, given that the formulaic approach (reflecting the data point as at February 28, 2025) did not result in a change in interest rates of 25 basis points or more.

Also similar to DVAs, the prescribed interest rates applicable to the CWIP account shall continue to reflect the respective data point at the end of the month that is one month prior to the start of the quarter (e.g., a November 30 data point for the quarter starting January 1). These rates will be published on the OEB's website shortly thereafter, effective for the next quarter (e.g., January 1 to March 31).

The OEB disagrees with Concentric's view that the current approach that applies a mid-term cost of debt to CWIP balances has the potential to significantly understate the cost of capital for utilities during the construction phase of projects.

The OEB is of the view that utilities typically fund capital projects using debt financing rather than equity during the construction phase. This aligns with standard utility capital structures, where debt comprises the majority of financing. The WACC includes an equity component, which compensates investors for assuming long-term business risk. However, utilities do not face the same level of risk on CWIP balances, as these costs (as long as they have been prudently incurred) are generally recovered through rates once the project is in service. During construction, utilities do not earn a ROE on the capital. Instead, they are incurring financing costs, which are predominantly debt-based. Accordingly, applying WACC to CWIP would overcompensate utilities by allowing them to earn an equity return on assets that are not yet providing service to ratepayers. The OEB finds that the approach of applying a cost of debt to CWIP is consistent with the principle of cost causality. The OEB concludes that a mid-term debt rate is reasonable to be used until the asset is added to rate base, on which the WACC applies.

Also as submitted by OEB staff, the OEB has a 2010 policy as stated in its Infrastructure Investment Report. While the primary focus of this policy was alternative cost recovery mechanisms for investments driven by the *Green Energy and Green Economy Act, 2009*, it did acknowledge that these cost recovery mechanisms could be proposed for other types of investments.[80] In the Infrastructure Investment Report, the OEB emphasized that the conventional mechanisms for cost recovery should be the OEB's core approach, but also described two alternative mechanisms that could be proposed:

- Accelerated cost recovery mechanisms: CWIP and pre-commercial expenses, and adjusting depreciation
- Incentive mechanisms: project-specific ROE and project specific capital structure.[81]

While there is limited experience applying the policy from the Infrastructure Investment Report, utilities can make applications for consideration by the OEB on a case-by-case basis for alternative cost recovery mechanisms for significant new infrastructure investments. The Infrastructure Investment Report also established the test for alternative mechanisms. Given this established policy to review proposals on a case-by-case basis, the OEB sees no need to make a generic change to the conventional mechanism for the treatment of CWIP.

These alternative mechanisms may be appropriate for rate-regulated infrastructure investment by Indigenous business ventures in the transmission sector. As noted in the Infrastructure Investment Report, additional mechanisms can also be proposed. The OEB finds that for TFG/Minogi the appropriate forum to consider unique issues related

[80] *Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, January 15, 2010 (EB-2009-0152), p. ii.
[81] *Ibid.*

to First Nations owned utilities, including the application of CCR, would be a proposal in a rate application by such a utility. It is out of scope of this generic proceeding for the current panel of Commissioners to initiate another generic proceeding to consider the financing matters raised by First Nations.

3.8 Cloud Computing Deferral Account

3.8.1 Continuation of the Account

Expert Report Proposals

No expert made comments on this issue in its report, as the issues list focused on what interest rate should apply to the account. The OEB's Accounting Order suggests that the continuance of this DVA be addressed at rebasing by stating [emphasis added]:[82]

> The deferral account is generally intended to record cloud computing implementation costs when utilities first transition from on-premise solutions to cloud computing solutions. **At the utility's next rebasing rate proceeding, a utility may propose the regulatory treatment for any material cloud implementation costs expected during its rate-setting term**. The proposal could include consideration of a new deferral account or other approaches that take into account the timing and duration of the contract term. **Furthermore, the utility's proposal for cloud computing implementation costs is expected to be informed by any results of the generic proceeding related to this issue.**

Submissions

OEB staff submitted that it is clear from the above excerpt from the Accounting Order that the Cloud Computing deferral account is not expected to be an on-going generic account. On the contrary, OEB staff noted that it is expected that utilities are to propose the regulatory treatment of any material cloud implementation costs expected during its rate term in cost-based applications.

Findings

The Cloud Computing deferral account was set up for instances when utilities incur material expenditures on their initial transition from on-premise solutions to cloud

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

computing solutions so as to mitigate disincentives during an IRM term to select optimal solutions.

At the next rebasing rate application following establishment of the account in November 2023, the utility can propose methods for disposition of the account for the OEB's approval. The nature of the cloud solution should be considered in determining the disposition methodology. That consideration would include the timing and duration of any contract term and the magnitude of the expenditure. Recovery would generally be expected to be over the remaining contract term unless the utility has a strong rationale for doing otherwise. In the same application, the utility can propose the treatment of any future cloud solutions during the rate term, which could include a new cloud solution deferral account. If no proposal is made in that rebasing rate application, the account will be closed.

3.8.2 Carrying Charges (Issue 22)

Expert Report Proposals

LEI suggested that the OEB needs to determine if the risk profile of the transition to cloud computing solutions warrants an additional risk premium over and above the carrying charges for DVAs (i.e., a higher rate than the prescribed interest rates for DVAs, which is currently allowed for the Cloud Computing deferral account).

LEI stated that a deemed WACC is necessary as a means of aligning incentives for utilities to transition to cloud computing solutions. LEI recommended that the OEB employ a deemed capital additions approach, which allows deemed WACC on the unamortized portions of the cloud computing contracts. Concentric agreed with both points made by LEI.

LEI also recommended that the prescribed interest rate for the DVAs be applied to 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 unamortized portion of the cloud-based contracts (contract value minus amortized costs) as deemed capital additions to incentivize the transition to cloud-based software solutions.

LEI stated that a deemed WACC (determined as of the year of rebasing or the year of disposition, for the remaining term of the contract) for all utilities should be allowed on the deemed capital additions. 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.

LEI stated 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. Otherwise, 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.

Concentric stated that it is important from a regulatory policy perspective that utilities are not disincentivized to pursue cloud computing solutions, and further to ensure that utility decisions consider the best operational outcomes (and therefore lowest long term customer cost). Concentric recommended that cloud solutions should be treated on par with in-house capitalized IT systems.

Concentric stated that the Cloud Computing deferral account is different from other DVAs because it involves utility choices, and thus the incentives behind those choices should be considered in setting the carrying cost rate. Concentric recommended that the WACC apply to Cloud Computing deferral account carrying costs, in order to incentivize utilities to invest in beneficial cloud computing technologies.

Nexus and Dr. Cleary did not comment on this issue in their reports.

Submissions

OEB staff and a number of ratepayer groups submitted that the Cloud Computing deferral account should be treated like any other deferral account: the carrying charge should be the prescribed interest rate for DVAs.

OEB staff was not persuaded that a departure from the usual approach is warranted. In OEB staff's view, the establishment of the Cloud Computing account was in itself sufficient incentive for utilities to transition to the cloud; an additional incentive by means of a higher carrying charge is not needed. Moreover, LEI's suggested approach (using three potential rates for different components of the recorded amounts -- prescribed interest rate for DVAs, WACC, and CWIP rate) would be administratively complicated.[83]

[83] LEI's layered approach is to reflect the deemed WACC on the unamortized portions of the cloud computing contracts, the prescribed interest rate for the CWIP account on the recorded incremental

The OEA generally supported Concentric's proposals. The OEA disagreed with OEB staff and SEC that the establishment of a DVA provides sufficient incentives to transitioning to cloud-based solutions. The OEA explained that a return on "traditional capital IT investments" is at each utility's WACC, not the prescribed interest rate for DVAs. The OEA further stated that providing a substantially different return than available on traditional investments does not remove the disincentive.

Some ratepayer groups stated that the risk profile of cloud computing-related costs is no different than other costs recorded in the various DVAs available to utilities, also suggesting that cloud computing solutions are less risky than typical utility IT services. CCC submitted that the treatment of unamortized cloud computing costs is appropriately addressed at rebasing when a utility brings forward those costs.

SEC noted that LEI's recommendation to treat the unamortized balance at rebasing as a deemed capital addition attracting WACC goes beyond providing information to inform a utility's proposal, it suggests a specific regulatory treatment. SEC submitted that this was not what the OEB intended when it issued the Accounting Order, nor is it covered by the approved issues list. In SEC's view, parties might have engaged experts to address that specific question if they had known that was within the scope.

Findings

The OEB agrees that there should not be a disincentive for utilities to use cloud-based solutions if they are the optimal system. Providing incentives for doing so is a different matter. The OEB expects utilities to adopt the best solutions by considering the costs and benefits and selecting the solution that best balances both. Utilities should not need to be incentivized to do the right thing.

Given that the current Cloud Computing deferral account was issued on a transitional basis until the utility's next rebasing application, the OEB concludes that there is no need to adopt a different methodology for carrying charges than is usually applied to DVAs. The prescribed interest rate for DVAs will therefore continue to apply to the Cloud Computing deferral account. The OEB is making this decision without prejudice to what the OEB may decide in a rate application for rate treatment of future cloud solutions during the rate term.

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capital costs until it is capitalized, and the prescribed interest rate for the DVAs on the incremental operating costs.

The OEB agrees with SEC that the treatment of cloud computing projects at rebasing goes beyond the scope of this proceeding. Utilities can make proposals as part of their rebasing rate applications for the rate treatment of the unamortized balance of their cloud-based solutions and for any future projects. This should consider the risk profile of cloud computing solutions versus on-premise solutions and different options that are available for the rate treatment. There is insufficient evidence to assess that risk on a generic basis in this proceeding.

4 COST AWARDS

The following parties (collectively the Eligible Participants) applied for and were granted cost award eligibility:

- Association of Major Power Consumers in Ontario (AMPCO)
- Association of Power Producers of Ontario (APPrO)
- Building Owners and Managers Association (BOMA)
- Caldwell First Nation (CFN)
- Canadian Manufacturers & Exporters (CME)
- Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Industrial Gas Users Association (IGUA)
- Minogi Corp. (Minogi)
- Mississaugas of the Credit First Nation (MCFN)
- Pollution Probe
- School Energy Coalition (SEC)
- Three Fires Group Inc. (TFG)
- Vulnerable Energy Consumers Coalition (VECC)

As noted in Procedural Order No. 1,[84] approved costs will be recovered from all rate-regulated electricity distributors, rate-regulated electricity transmitters, rate-regulated natural gas utilities, and rate-regulated electricity generators (collectively, rate-regulated companies). The four groups will each be allocated a 25% share and in turn the costs will be sub-allocated amongst the utilities comprising that group using the OEB's Cost Assessment Model. No objections to this approach were filed.

On October 7, 2024, the OEB issued a Decision and Order on Interim Cost Awards which approved interim cost awards filed by AMPCO, APPrO, BOMA, CFN, CME, CCMBC, CCC, Energy Probe, IGUA, MCFN, Minogi, SEC, and TFG. The OEB stated that it would conduct a complete review of all cost claims for the entire proceeding at its conclusion.

[84] Procedural Order No. 1, March 28, 2024.

Eligible Participants that applied for and received interim cost awards up to, and including, September 6, 2024, are required to submit an incremental cost claim, if incremental costs are being claimed. Other Eligible Participants that did not apply for and receive interim cost awards may submit a total cost claim.

The cost claims are to be filed in accordance with the OEB's Practice Direction on Cost Awards.

Provision is being made for the rate-regulated companies to file any objections, and any Eligible Participants whose claims were subject to objections will have an opportunity to reply. The OEB will then determine the Eligible Participants' entitlement to a cost award, including any amount received as an interim award, and interim awards of costs may be subject to adjustment.

Provision is being made for recovery from rate-regulated companies of the OEB's costs of and incidental to this proceeding.

The OEB will issue its cost awards decision after the steps outlined in the following Order section are completed.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The following cost of capital parameters are approved on a final basis, effective January 1, 2025. Please refer to the Decision for details regarding implementation and applicability.

    a. The Deemed Return on Equity is 9.00% (inclusive of 25 basis points for flotation costs)

    b. The Deemed Long-Term Debt Rate is 4.51%

    c. The Deemed Short-Term Debt Rate is 3.91%

2. The cost of capital parameters will be updated annually in accordance with the methodologies set out in the Decision.

3. For Q2 2025, the final prescribed interest rate for deferral and variance accounts is 3.16%, effective April 1, 2025.

4. For Q2 2025, the final prescribed interest rate for construction work in progress is 4.23%, effective April 1, 2025.

5. The prescribed interest rates will be updated quarterly in accordance with the methodologies set out in the Decision.

6. No changes to the deemed equity ratio have been made.

7. The prescribed interest rate for deferral and variance accounts will continue to apply to the Cloud Computing deferral account.

8. Any rate-regulated utility that issues new long-term debt in excess of $50 million (whether directly or through an affiliate) must report this to the OEB once a year (by April 30 for debt issued in the prior calendar year), including quantity, term, and interest rate. The report must be sent to the OEB's performance reporting email address (performance_reporting@oeb.ca) and to the Registrar.

Cost Awards

9. Cost-eligible intervenors that applied for and received interim cost awards are required to submit an incremental cost claim for work performed after September 6, 2024 by **April 7, 2025**, if incremental costs are being claimed. A copy of each claim

must be filed with the OEB. Rate-regulated companies may check the record of this proceeding for these cost claims.

10. Cost-eligible intervenors that did not apply for or receive interim cost awards may submit a total cost claim by **April 7, 2025**. A copy of each claim must be filed with the OEB. Rate-regulated companies may check the record of this proceeding for these cost claims.

11. Rate-regulated companies shall file with the OEB and forward to all intervenors any objections to the claimed costs of the intervenors on or before **April 17, 2025**.

12. If rate-regulated companies object to any intervenor costs, those intervenors shall file with the OEB their responses, if any, to the objections to cost claims on or before **April 28, 2025**. Rate-regulated companies may check the record of this proceeding for these responses from intervenors.

13. Rate-regulated companies shall pay the OEB's costs of and incidental to this proceeding upon receipt of the OEB's invoice.

Please quote file number, **EB-2024-0063** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the File documents online page on the OEB's website.
- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance.
- Cost claims are filed through the OEB's online filing portal. Please visit the File documents online page of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the Practice Direction on Cost Awards.

All communications should be directed to the attention of the Registrar and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Fiona O'Connell, at fiona.oconnell@oeb.ca and OEB Counsel, Ian Richler, at ian.richler@oeb.ca.

DATED at Toronto March 27, 2025

ONTARIO ENERGY BOARD

Nancy Marconi

Digitally signed by Nancy Marconi
Date: 2025.03.27 15:54:28 -04'00'

Nancy Marconi
Registrar

SCHEDULE A

TO

DECISION AND ORDER

EB-2024-0063

LIST OF PARTIES

March 27, 2025

Schedule A – List of Parties

Below is a list of parties to this proceeding.

Intervenors

Association of Major Power Consumers in Ontario
Association of Power Producers of Ontario
Building Owners and Managers Association
Caldwell First Nation
Canadian Manufacturers & Exporters
Coalition of Concerned Manufacturers and Businesses of Canada
Consumers Council of Canada
Energy Probe Research Foundation
Industrial Gas Users Association
Minogi Corp.
Mississaugas of the Credit First Nation
Pollution Probe
School Energy Coalition
Society of United Professionals
Three Fires Group Inc.
Vulnerable Energy Consumers Coalition

Utilities

Alectra Utilities Corp.
Bluewater Power Distribution Corp.
Elexicon Energy Inc.
Enbridge Gas Inc.
Enova Power Corp.
Entegrus Powerlines Inc.
ENWIN Utilities Ltd.
EPCOR Electricity Distribution Ont. Inc.
FortisOntario Inc.
GrandBridge Energy Inc.
Halton Hills Hydro Inc.
Hydro One Networks Inc.
Hydro Ottawa Limited
Niagara Peninsula Energy Inc.
Ontario Power Generation Inc.

Orangeville Hydro Ltd.
Toronto Hydro-Electric System Ltd.
Upper Canada Transmission 2, Inc.

Utility Associations

Electricity Distributors Association
Ontario Energy Association [85]

[85] The OEA is acting on behalf of the CLD+. The CLD+ comprises Alectra Utilities, Elexicon Energy, Enbridge Gas, Hydro One Networks, Hydro Ottawa, Ontario Power Generation, Toronto Hydro-Electric System, and Upper Canada Transmission 2.

SCHEDULE B

TO

DECISION AND ORDER

EB-2024-0063

ISSUES LIST

March 27, 2025

Schedule B – Issues List

Schedule B provides the Issues List to this proceeding, as approved by the OEB on April 22, 2024.

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.)

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

3. 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?

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?[86]

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

[86] 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.

C. Long-Term Debt Rate

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?[87]

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

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

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?

D. Return on Equity

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

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?

E. Capital Structure

12. How should the capital structure be set for electricity transmitters, electricity distributors, natural gas utilities, and OPG to reflect the FRS?

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?

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[87] 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.

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?

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?

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?

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?

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)?

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?

G. Other Issues

a) Prescribed Interest Rates

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?[88]

[88] 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.

21. If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?

b) 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?[89]

[89] 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.

SCHEDULE C

TO

DECISION AND ORDER

EB-2024-0063

SUMMARY OF REVISED COST OF CAPITAL METHODOLOGY

March 27, 2025

Schedule C – Revised Methodology – Cost of Capital

The revised methodology for calculating the cost of capital is summarized in Table 2 below.

Table 2 – Summary of Revised Methodology – Cost of Capital

	Electricity Distributors and Transmitters	OPG's Prescribed Generation Assets	Natural Gas Distributors	
			Enbridge Gas Inc.	EPCOR Natural Gas LP
Deemed Capital Structure	40% equity, 56% long-term debt, 4% short term debt	45% equity, 55% debt[90] The capital structure shall be determined at its next cost-based rates application.	38% equity, 62% debt[91] The capital structure shall be determined at its next cost-based rates application.	South Bruce service territory[92] 36% equity, 60% long-term debt, 4% short term debt Aylmer service territory[93] 40% equity, 56% long-term debt, 4% short term debt The capital structure for the South Bruce service territory shall be determined at its next cost-based rates application.
Return on Equity Formula (ROE)	$ROEt = 9.00\% + 0.5 \times (LCBFt - 3.13\%) + 0.5 \times (UtilBondSpreadt - 1.38\%)$ $ROEt$ is the ROE for year t, $LCBFt$ is the Long Canada (30-year Government of Canada) Bond yield actual data point as at September 30 for year t, and $UtilBondSpreadt$ is the spread between 30-year A-rated Utility Corporate Bond yield and Long Canada (30-year Government of Canada) Bond Yield, using actual data points as at September 30. The data for $LCBFt$ and $UtilBondSpreadt$ are derived from the Bank of Canada and Bloomberg LP data for the month three months in advance of the effective date of the cost of capital parameters.			

[90] EB-2020-0290, Exhibit 0, Tab 1, Schedule 1, Page 37, July 16, 2021.
[91] EB-2022-0200, Rate Order, Working Papers, Schedule 11, Page 1, February 16, 2024.
[92] EB-2018-0264, Exhibit 5, Tab 1, Schedule 1, Page 2, April 11, 2019.
[93] EB-2024-0130, Exhibit 5, Tab 1, Schedule 1, Page 8, July 18, 2024; Decision and Order, January 14, 2025, Settlement Proposal, November 20, 2024, p. 25.

	Electricity Distributors and Transmitters	OPG's Prescribed Generation Assets	Natural Gas Distributors: Enbridge Gas Inc.	Natural Gas Distributors: EPCOR Natural Gas LP
	Thus, for cost of capital updates effective January 1, September data are used. The same numbers are used for rates effective May 1.			
Long-term debt rate	Weighted average of embedded (actual) debt plus forecasted debt rate(s) of new debt in the test period. A deemed long-term debt rate based on the following formula serves as a ceiling when there is no debt, variable or callable debt, debt without a fixed term, or debt that is not market-based. With respect to affiliated debt, the DLTDR will apply as a ceiling for all debt held with a municipal government shareholder for all utilities at the time of issuance. For affiliated debt held by the holding company, other affiliated company or related party of a rate regulated utility, the utility must explain how the debt rate is no higher than it would have been if funds were borrowed directly by	Weighted average of embedded (actual) debt plus forecasted debt rate(s) of new debt in the test period. For affiliated debt held by the holding company, other affiliated company or related party of a rate regulated utility, the utility must explain how the debt rate is no higher than it would have been if funds were borrowed directly by the utility through the external markets.	Weighted average of embedded (actual) debt plus forecasted debt rate(s) of new debt in the test period. For affiliated debt held by the holding company, other affiliated company or related party of a rate regulated utility, the utility must explain how the debt rate is no higher than it would have been if funds were borrowed directly by the utility through the external markets.	The same approach to long-term debt rates applies as per electricity distributors and transmitters. For affiliated debt held by the holding company, other affiliated company or related party of a rate regulated utility, the utility must explain how the debt rate is no higher than it would have been if funds were borrowed directly by the utility through the external markets.

	Electricity Distributors and Transmitters	OPG's Prescribed Generation Assets	Natural Gas Distributors: Enbridge Gas Inc.	Natural Gas Distributors: EPCOR Natural Gas LP
	the utility through the external markets. $DLTDRt = LCBFt + UtilBondSpreadt$			
Short-term debt rate	D$STDR_t$ = BVCAUA3M BVLI$_t$ BVCAUA3M BVLI$_t$ is the Bloomberg ticker BVCAUA3M BVLI Index (3-month), with the data point as at September 30, taken from Bloomberg LP, for year t.	The estimated short term debt cost is used. OPG has methodologies that have been approved by the OEB in earlier decisions.	The estimated short term debt cost is used. Enbridge Gas has methodologies that have been approved by the OEB in earlier decisions.	The same short-term debt rates are used as per electricity distributors and transmitters.
Prescribed Interest Rates	The prescribed interest rates applicable to DVAs and CWIP shall be set quarterly. These rates will only be updated if the formulaic approach results in a change in interest rates of 25 basis points or more. Otherwise, the previous quarter's prescribed interest rate will be maintained for the following quarter. The prescribed interest rates applicable to DVAs and CWIP shall continue to reflect the respective data point at the end of the month that is one month prior to the start of the quarter (e.g., a November 30 data point for the quarter starting January 1). These rates will be published on the OEB's website shortly thereafter, effective for the next quarter (e.g., January 1 to March 31). DVAs will reflect the Bloomberg ticker BVCAUA3M BVLI Index (3-month) data point taken from Bloomberg LP. CWIP will reflect the FTSE Canada Mid Term Bond Index All Corporate yield, taken under contract from PC Bond Analytics, a business unit of FTSE.			

SCHEDULE D

TO

DECISION AND ORDER

EB-2024-0063

REVISED METHODOLOGY TO UPDATE THE RETURN ON EQUITY

March 27, 2025

Schedule D – Revised Methodology – Return on Equity

The revised methodology for calculating the ROE is summarized below.

With the release of this Decision, the OEB is resetting and refining its formulaic approach for determining a utility's ROE applicable to the prospective test year.

The annual ROE adjustment formula as set out in this Decision includes (a) a term to reflect the change in the LCBF and (b) a term to reflect the change in the spread between A-rated Utility bond yields over the Long Canada Bond yield.

The adjustment factor for the LCBF term is set at 0.5. The adjustment factor for the A-rated Utility bond yield spread is set at 0.5.

The base for the annual ROE adjustment formula is set at 9.00%. The corresponding base LCBF is 3.13% and the spread in 30-year A-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield is 1.38%.

The formula for the annual update of ROE is:

ROE_t = 9.00% + 0.5 × ($LCBF_t$−3.13%) + 0.5 × ($UtilBondSpread_t$−1.38%)

Where:

> $LCBF_t$ will be calculated using the actual Long Canada (30-year Government of Canada) Bond yield (taken from Bank of Canada series V39056) as at September 30 for year t.
>
> $UtilBondSpread_t$ will be calculated as the spread between the 30-year A-rated Utility Corporate Bond yield (taken from ticker Bloomberg BVCAUA30 BVLI Index) and Long Canada (30-year Government of Canada) Bond yield (taken from Bank of Canada series V39056) as at September 30 for year t.

The ROE for any period will be rounded and expressed as a percentage with two decimal places (i.e., XX.XX%).

The use of the ROE will be in accordance with the policy described in Section 3.2 of this Decision.

SCHEDULE E

TO

DECISION AND ORDER

EB-2024-0063

REVISED METHODOLOGY TO UPDATE THE DEEMED LONG-TERM DEBT RATE

March 27, 2025

Schedule E – Revised Methodology – Deemed Long-Term Debt Rate

The revised methodology for calculating the DLTDR is summarized below.

The OEB will use the LCBF plus a spread of 30-year A-rated Corporate Utility bond yields over the actual Long Canada (30-year Government of Canada) Bond yield to determine the updated DLTDR.

The formula for the annual update of the DLTDR is:

$DLTDR_t = LCBF_t + UtilBondSpread_t$

Where:

> $LCBF_t$ will be calculated using the actual Long Canada (30-year Government of Canada) Bond yield (taken from Bank of Canada series V39056) as at September 30 for year t.
>
> $UtilBondSpread_t$ will be calculated as the spread between the 30-year A-rated Utility Corporate Bond yield (taken from ticker Bloomberg BVCAUA30 BVLI Index) and the Long Canada (30-year Government of Canada) Bond yield (taken from Bank of Canada series V39056) as at September 30 for year t.

The DLTDR for any period will be rounded and expressed as a percentage with two decimal places (i.e., XX.XX%).

The use of the DLTDR will be in accordance with the policy described in Section 3.4 of this Decision.

SCHEDULE F

DECISION AND ORDER

EB-2024-0063

REVISED METHODOLOGY TO UPDATE THE DEEMED SHORT-TERM DEBT RATE

March 27, 2025

Schedule F – Revised Methodology – Deemed Short-Term Debt Rate

The revised methodology for calculating the DSTDR is summarized below.

The OEB will use a methodology to estimate the DSTDR consisting of the September 30 data point sourced from the Bloomberg ticker BVCAUA3M BVLI Index (3-month) in each year.

The formula for the annual update of the DSTDR is:

$DSTDR_t$ = BVCAUA3M BVLI$_t$

Where:

> *BVCAUA3M BVLI$_t$* is the Bloomberg ticker BVCAUA3M BVLI Index (3-month), with the data point as at September 30, taken from Bloomberg LP, for year t.

Alternative Formula

If at any point, the BVCAUA3M BVLI Index (3-month) becomes unavailable in its current form, the OEB concludes that it is reasonable to calculate the DSTDR using the actual CORRA reference rate as at September 30. Applied to this would be an average estimate of the spread for short-term 3-month loans over the CORRA for R1-low or A (A-stable) commercial utility customers, based on an annual confidential survey of at least three Canadian banks, with no outliers used.

Once a year, in September, the above noted confidential survey would be obtained by OEB staff contacting major Canadian banks.

If market conditions materially change, the OEB could decide that the average spread may need to be updated at some point other than September.

The alternative formula for the annual update of the DSTDR is:

$DSTDRt$ = CORRA + $AnnSpreadt$

Where:

> *CORRA* is the data point as at September 30, taken from the Bank of Canada, for year t.

$AnnSpreadt$ is the average estimate of the spread for short-term 3-month loans over the CORRA for R1-low or A (A-stable) commercial utility customers, from a confidential survey of at least three Canadian banks, conducted annually.

The DSTDR for any period will be rounded and expressed as a percentage with two decimal places (i.e., XX.XX%).

The use of the DSTDR will be in accordance with the policy described in Section 3.5 of this Decision.

SCHEDULE G

DECISION AND ORDER

EB-2024-0063

REVISED METHODOLOGY TO UPDATE THE PRESCRIBED INTEREST RATES

March 27, 2025

Schedule G – Revised Methodology – Prescribed Interest Rates

The revised methodology for calculating the prescribed interest rates is summarized below.

The prescribed interest rates applicable to DVAs and CWIP shall continue to be set quarterly. These rates will only be updated if the formulaic approach results in a change in interest rates of 25 basis points or more. Otherwise, the previous quarter's prescribed interest rate will be maintained for the following quarter.

The prescribed interest rates applicable to DVAs and CWIP shall continue to reflect the respective data point at the end of the month that is one month prior to the start of the quarter (e.g., a November 30 data point for the quarter starting January 1). These rates will be published on the OEB's website shortly thereafter, effective for the next quarter (e.g., January 1 to March 31).

DVAs

DVAs will reflect the Bloomberg ticker BVCAUA3M BVLI Index (3-month) data point taken from Bloomberg LP. The formula for the quarterly update of the prescribed interest rate for DVAs is:

$DVAS_t$ = BVCAUA3M $BVLI_t$

Where:

> *BVCAUA3M* $BVLI_t$ is the Bloomberg ticker BVCAUA3M BVLI Index (3-month), with the data point as at the end of the month that is one month prior to the start of the quarter, taken from Bloomberg LP, for quarter t.

CWIP

CWIP will reflect the FTSE Canada Mid Term Bond Index All Corporate yield, taken under contract from PC Bond Analytics, a business unit of FTSE. The formula for the quarterly update of the prescribed interest rate for CWIP is:

$CWIP_t$ = FTSE Canada Mid Term Bond Index All $Corporate_t$

Where:

> *FTSE Canada Mid Term Bond Index All* $Corporate_t$ is the FTSE Canada Mid Term Bond Index All Corporate yield, with the data point as at the end of the

month that is one month prior to the start of the quarter, taken and under contract from PC Bond Analytics, a business unit of FTSE, for quarter t.

The prescribed interest rates for any period will be rounded and expressed as a percentage with two decimal places (i.e., XX.XX%).

The use of the prescribed interest rates will be in accordance with the policy described in Section 3.7 of this Decision.

SCHEDULE H

DECISION AND ORDER

EB-2024-0063

CURRENT COST OF CAPITAL FRAMEWORK

March 27, 2025

Schedule H – Current Cost of Capital Framework

Background of Current Framework

The OEB last reviewed its cost of capital methodology in 2009 culminating in its 2009 Report dated December 11, 2009.[94] The Staff Report on the cost of capital policy was published on January 14, 2016.[95] OEB staff concluded in the Staff Report that the methodology adopted in late 2009 was working as intended.

In the 2009 Report, the OEB determined that the ERP approach remained the most appropriate approach to setting the base ROE.[96] The OEB noted the known weaknesses of differing approaches, and determined that no single test could be used to satisfy the FRS.[97] The OEB observed from the participants' analyses that the ROE determined through various approaches can be expressed as an absolute number or as an ERP over a risk-free rate.[98] The OEB found that expressing the ROE as a premium above the long-term Canada bond yield did not require estimating the initial ROE using only ERP-based tests. Instead, the OEB determined that relying on multiple tests, including tests that directly and indirectly estimated the ERP, provided a better foundation for judgement than the reliance on a single methodology.[99]

The Fair Return Standard

The OEB confirmed six key regulatory principles with respect to its cost of capital policy in the 2009 Report, with one of those being the FRS.[100] All three requirements of the FRS – comparable investment, financial integrity and capital attraction – must be met and none ranks in priority to the others.

The 2009 Report noted 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 2009 Report also noted that each time a formulaic approach is used to calculate an allowed ROE, it must generate a number that meets the FRS, as determined by the

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[94] EB-2009-0084.
[95] EB-2009-0084.
[96] 2009 Report, p. 26.
[97] 2009 Report, p. 26.
[98] 2009 Report, p. 26.
[99] 2009 Report, p. 36, 37.
[100] 2009 Report, pp. 31 & 32. The six principles were: 1) Fair Return Standard; 2) The overall ROE must be determined solely on the basis of a company's cost of equity capital; 3) Efficient amount of investment; 4) Predictability, transparency, and stability; 5) Systematic and empirically-based approach; 6) Minimize the time and cost of administering the framework.

OEB using its experience and informed judgement.

Base Return on Equity

In the 2009 Report, the OEB determined a LCBF of 4.25% and an ERP of 5.50%, which summed to the base ROE of 9.75% (9.75% = 4.25% + 5.50%).[101]

The ERP was determined based on the average ERP of participant recommendations, with participants using a mix of approaches, as noted in the 2009 Report.[102] The OEB considered the low end of the ERP submitted by the participants. The ERP of 5.50% included 50 basis points for flotation[103] costs.

For 2025 rates, the OEB approved an ROE of 9.25% on an interim basis, as well as a generic variance account related to the ROE.[104]

Equity Transaction/Flotation Costs

The current base ROE methodology includes 50 basis points for transaction costs (i.e., the base ROE of 9.75% includes 0.50% of transaction costs), as noted in the 2009 Report.[105]

Updates to Return on Equity

In the 2009 Report, the annual ROE adjustment formula was set as below:[106]

$$ROE_t = 9.75\% + 0.5 \text{ x } (LCBF_t – 4.250\%) + 0.5 \text{ x } (UtilBondSpread_t – 1.415\%)$$

The OEB adjusted the ROE annually by adjusting LCBF and utility bond spread based on current data. The following parameters in the formula are, however, fixed:

(i) Base ROE
(ii) LCBF adjustment factor
(iii) Utility bond spread adjustment factor
(iv) Base LCBF

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[101] 2009 Report, pp. ii, 37, 59.
[102] 2009 Report, p. 38, Table 1: Summary of Participant Recommendations where the column “Low” was used by the OEB to calculate the ERP of 5.50%.
[103] The 2009 Report used the terms transaction costs and flotation costs interchangeably.
[104] OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024.
[105] 2009 Report, pp. ii, 37, 59.
[106] 2009 Report, p. VI.

(v) Base A-rated utility bond yield spread.

The OEB set the LCBF adjustment factor and utility bond spread adjustment factor as 0.5 based on regression analysis performed by participants, as noted in the 2009 Report.[107] The OEB concluded that there was 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 annual ROE adjustment formula.[108]

Based on September 2009 data, the OEB set the base LCBF at 4.250% and the base utility bond spread at 1.415%.[109]

Capital Structure General Approach

The 2009 Report continued the deemed equity ratio of 40% equity / 60% debt for electricity distributors established previously by the OEB in 2006.[110] The 2009 Report said that for electricity transmitters, generators, and gas utilities, the deemed capital structure would continue to be determined on a case-by-case basis.[111]

Since the 2009 Report, the OEB has extended the deemed equity ratio of 40% to electricity transmitters. Ontario has nine licensed electricity transmitters.[112] LEI noted that as of 2022, Hydro One accounted for around 91% of the total approved rate base for electricity transmitters.[113] Currently, of the nine transmitters, three are single-asset transmitters. Single-asset electricity transmitters have the same deemed equity ratio as multiple asset transmitters.

The equity ratio for gas utilities and OPG is still set on a case-by-case basis. Enbridge Gas's current deemed equity ratio is 38%.[114] EPCOR Natural Gas's is 36% for the South Bruce service territory[115] and 40% for the Aylmer service territory.[116] OPG's current deemed equity ratio is 45%.[117]

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107 2009 Report, pp. ii, 46, 47, 49, 59, VI.
108 2009 Report, p. ii.
109 2009 Report, p. VI.
110 2009 Report, p. 50 (citing the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006).
111 2009 Report, p. 50
112 OEB List of licensed companies.
113 LEI Expert Report, June 21, 2024, Revised September 23, 2024, p. 141.
114 EB-2022-0200, Rate Order, Working Papers, Schedule 11, Page 1, February 16, 2024.
115 EB-2018-0264, Exhibit 5, Tab 1, Schedule 1, Page 2, April 11, 2019.
116 EB-2024-0130, Exhibit 5, Tab 1, Schedule 1, Page 8, July 18, 2024; EB-2024-0130, Decision and Order, January 14, 2025, Settlement Proposal, November 20, 2024, p. 25.
117 EB-2020-0290, Exhibit 0, Tab 1, Schedule 1, Page 37, July 16, 2021.

The OEB sets a uniform ROE for all regulated entities, and it can increase (or decrease) the equity thickness in the capital structure if it assesses that an entity's business and financial risks have increased (or decreased) relative to the previous assessment. The approach to setting the cost of capital parameters and capital structure does not depend on a utility's ownership.[118]

Approach to Long-Term Debt

The status quo approach to the long-term debt rate is to use the weighted average of embedded (actual) debt plus forecasted debt rate(s) of new debt in the test period.

For Enbridge Gas and OPG, the DLTDR is not used to set long-term debt rates.

For electricity distributors and transmitters (and EPCOR Natural Gas), a DLTDR based on the following formula serves as a ceiling in certain circumstances, as outlined in the 2009 Report:[119]

$$DLTDR_t = LCBF_t + UtilBondSpread_t$$

Where:

> $LCBF_t$ is the Long Canada (30-year Government of Canada) Bond yield forecast for year t.
>
> $UtilBondSpread_t$ is the spread between 30-year A-rated Utility Corporate Bond yields and Long Canada (30-year Government of Canada) Bond Yields.

The data for $LCBF_t$ and $UtilBondSpread_t$ are derived from Consensus Forecasts,[120] the Bank of Canada, and Bloomberg LP data, for the month that is three months in advance of the effective date of the cost of capital parameters. For cost of capital updates effective January 1 or May 1, September data are used.

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 (typically in September), and adding the average of the

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[118] 2009 Report, pp. 25, 26, 31.
[119] 2009 Report, pp. 53 & 54 & VIII.
[120] Consensus Forecasts are surveys of international economic forecasts published by Consensus Economics Inc.

actual observed spreads between 10-year and 30-year Government of Canada bond yields, for each business day in the month corresponding to the Consensus Forecasts publication.[121]

For 2025 rates, the OEB approved a DLTDR of 4.66% on an interim basis, as well as a generic variance account related to the DLTDR.[122]

Long-term debt transaction costs are recorded as an interest expense and amortized over the term of the debt instrument (using the effective interest rate methodology).

The OEB currently does not consider transaction/financing costs associated with obtaining debt when determining the DLTDR.

Approach to Short-Term Debt

For Enbridge Gas and OPG, the DSTDR is not used to set short-term debt rates. Instead, the utility's estimated short term debt cost is used.

For electricity distributors and transmitters (and EPCOR Natural Gas), the status quo approach to short-term debt is to use the following DSTDR:[123]

$DSTDR_t = AvgBA_t + AnnSpread_t$

Where:

> $AvgBA_t$ is the average 3-month Bankers' Acceptance (BA) rate for the month 3 months prior to the cost of capital update, taken from the Investment Industry Regulatory Organization of Canada for year t.
>
> $AnnSpread_t$ is the average estimate of the spread for short-term loans over the 3-month BA rate from a confidential survey with major Canadian banks, conducted annually, for R1-low or A (A-stable) commercial utility customers.

Given the phase-out of BA rates (as discussed earlier in this Decision), the OEB approved the use of the Canada 3-month T-bill rate instead of BA rates for the 2025 DSTDR (on an interim basis), as well as the bank survey conducted in 2023. No

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[121] This paragraph describes the Canadian data stated in the Consensus Forecasts publication (typically September publication) that are used in the annual ROE adjustment formula.
[122] OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024.
[123] 2009 Report, p. IX.

confidential bank survey was conducted in September 2024, as explained in an OEB letter.[124]

For 2025 rates, the OEB approved a DSTDR of 5.04% on an interim basis, as well as a generic variance account related to the DSTDR.[125]

Variances from Deemed Capital Structure

The OEB sets rates using a deemed capital structure. The OEB sets the equity ratio at 40% and the short-term debt ratio at 4% for electricity distributors and transmitters. Although both of EPCOR Natural Gas's service territories use a short-term debt ratio of 4%, the utility's equity ratio is 36% for its South Bruce service territory[126] and 40% for its Aylmer service territory.[127]

Notional debt is the portion of deemed debt exceeding the actual debt of these utilities. Notional debt can be either positive (deemed debt is greater than actual debt) or negative (deemed debt is less than actual debt).[128] In the past, the OEB approved notional debt attracting a utility's weighted average cost of actual long-term debt rate in some instances and the DLTDR in other instances.

The equity ratio has been set for Enbridge Gas and OPG through adjudication at 38% and 45% respectively. For the unfunded portion of their capital structure, a short-term debt rate applies (which is based on actual/forecasted debt rates, as opposed to the DSTDR).

Implementation

Changes to the cost of capital parameters from the 2009 Report were implemented when a utility filed a cost-based rates application (i.e., upon rebasing).[129]

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[124] OEB Letter, Updated Inputs to the OEB's Prescribed Interest Rates and Cost of Capital Parameters, July 26, 2024.
[125] OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024; OEB Letter, Updated Inputs to the OEB's Prescribed Interest Rates and Cost of Capital Parameters, July 26, 2024.
[126] EB-2018-0264, Exhibit 5, Tab 1, Schedule 1, Page 2, April 11, 2019.
[127] EB-2024-0130, Exhibit 5, Tab 1, Schedule 1, Page 8, July 18, 2024; EB-2024-0130, Decision and Order, January 14, 2025, Settlement Proposal, November 20, 2024, p. 25.
[128] Staff Report, p. 7.
[129] 2009 Report, pp. 61 & 63.

The OEB regularly monitors macroeconomic conditions and updates the cost of capital parameters for setting rates once per year since the issuance of 2014 rates.[130]

The 2009 Report stated that each time a formulaic approach is used to calculate an allowed ROE, it must generate a number that meets the FRS, as determined by the OEB using its experience and informed judgement.

The OEB assesses whether the cost of capital parameter values issued as part of its annual updates, along with the relationships between the parameters, reasonably reflect market conditions at that time. As part of this assessment, the OEB determines whether the numerical results from the formulaic methodology satisfy the FRS.

In addition to the formulaic approach, an applicant or intervenor can also file evidence in individual rate hearings in support of different cost of capital parameters due to a utility's specific circumstances, but must provide a strong rationale and supporting evidence for departing from the OEB's policy.

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 generally rely on data from the month of September.[131]

Periodic Reviews of the Cost of Capital Framework

The 2009 Report 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 ROE continues to meet the FRS and the objective of maintaining regulatory efficiency and transparency."[132]

Following the 2009 Report, a Staff Report was issued in 2016, 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."[133] No other comprehensive reviews of the formulaic cost of capital policy have been conducted by the OEB until the current proceeding.

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[130] OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024. As per the OEB's website, for the 2011, 2012, and 2013 rate years, the cost of capital parameters were updated twice a year (i.e., for January 1 rates and May 1 rates).
[131] OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024; 2009 Report, p. 59.
[132] 2009 Report, p. 64.
[133] Staff Report, p. 1.

The following OEB trigger mechanisms are in place to determine whether there needs to be a departure from the new Cost of Capital Framework during its term:

- 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.[134]
- Electricity distributors 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 dead band of +/- 300 basis points from the OEB-approved ROE.[135]

Prescribed Interest Rates

The OEB's current practice is to set the prescribed interest rates applicable to DVAs and CWIP quarterly. These rates are only updated if the formulaic approach results in a change in interest rates of 25 basis points or more.[136] Otherwise, the previous quarter's prescribed interest rate is maintained.

The prescribed interest rates applicable to each of the DVAs and the CWIP account reflect the respective data point at the end of the month that is one month prior to the start of the quarter (e.g., a November 30 data point for the quarter starting January 1). These rates are published on the OEB's website shortly thereafter, effective for the next quarter (e.g., January 1 to March 31).

Up until Q3 2024, the prescribed interest rate applicable to DVAs was equal to the BA three-month rate, plus a spread of 25 basis points.

Since Q4 2024, the prescribed interest rate for DVAs has been based on the three-month T-bill rate, plus a 25-basis point spread,[137] with the methodology updated to reflect the phase-out of BA rates, as noted in Section 3.5 of this Decision. The prescribed interest rate for CWIP is currently determined using the FTSE Canada

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[134] OEB Letter, 2025 Cost of Capital Parameters, October 31, 2024.
[135] *Filing Requirements For Electricity Distribution Rate Applications Filed in 2024 for Rates Taking Effect in 2025, Chapter 3 Incentive Rate-Setting Applications*, June 18, 2024, p. 21.
[136] Per the OEB's Prescribed Interest Rates webpage; EB-2006-0117, OEB Letter, Approval of Accounting Interest Rates Methodology for Regulatory Accounts November 28, 2006.
[137] OEB Letter, Updated Inputs to the OEB's Prescribed Interest Rates and Cost of Capital Parameters, July 26, 2024.

(formerly DEX) Mid Term Bond Index All Corporate yield. CWIP accounting procedures are outlined in the OEB's APH.[138]

Cloud Computing Deferral Account

In November 2023, the OEB issued an accounting order establishing a generic Cloud Computing deferral account allowing utilities to "record cloud computing implementation costs when utilities first transition from on-premise solutions to cloud computing solutions".[139]

According to the OEB's Accounting Order, "carrying charges at the OEB's prescribed rates for deferral and variance accounts will apply to the account unless otherwise directed by the OEB." The Accounting Order further stated 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".

The Accounting Order also noted that this generic proceeding will determine whether carrying charges and/or another type of rate will be applied to this account.

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[138] Accounting Procedures Handbook For Electricity Distributors, Issued: December 2011, Effective: January 1, 2012, Article 220, p. 200; Article 410, pp. 27 & 28.
[139] Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs, issued November 2, 2023.