EB-2024-0063

ONTARIO ENERGY BOARD

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

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

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(LEI Witness Panel)

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

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

June 21st, 2024

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

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

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

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

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

LEI recommendations - Issue 1

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

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

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

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

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

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

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

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

4.2.1 Status quo

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

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

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

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

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

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

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

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

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

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

3. **Operational risk** refers to the uncertainties and hazards a company faces when it pursues its day-to-day business activities.[127] Examples of operational risk factors include the degradation of aging nuclear power station components (OPG), impacts of meteorological/geological events on gas pipeline infrastructure (Enbridge Gas), and the geographic size and isolation of the distributor's service area (electricity distributors). In 2014, the OEB considered the addition of 48 hydroelectric facilities to OPG's rate base since OEB's previous review to have reduced the business risk for OPG as the share of hydroelectric assets in the rate base increased (OEB considered hydroelectric facilities to be lower risk than nuclear facilities).[128]
4. **Regulatory risk** refers to the impacts of OEB policies/regulatory mechanisms. For instance, in addition to the reduction of operational risk described above, the OEB also considered the addition of several DVAs since its last review (particularly the addition of a new pension variance account) to have reduced business risks for OPG. In 2017, the transition to incentive-based rates was considered a factor increasing OPG's business risks in its rate application, however, the OEB did not accept this argument.[129]
5. **Policy risk** refers to the impacts of Ontario, federal or municipal government policies/legislations. For instance, introducing the federal carbon price was considered to increase Enbridge Gas' risk by making alternative heating technologies more attractive. Policy risk can also increase when rates increase significantly in a short period of time, typically within 1-2 years (such as when higher natural gas prices in 2022 lead to dramatic increases in electric and gas distribution rates in many jurisdictions), triggering affordability concerns for customers. In such scenarios, the risk of rate freezes is higher.

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

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

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

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

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

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

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

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

Notes: Key terms defined as follows:

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

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

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

"Interest" defined as total interest expense.

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

4.2.2 Relevant jurisdictional review

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

Alberta:

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

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

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

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

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

Australia

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

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

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

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

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

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

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

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

British Columbia

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

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

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

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

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

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

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

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

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

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

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

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

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

[143] Ibid. Page 54.

[144] Ibid. Page 36.

[145] Ibid. Page 38.

[146] Ibid. Page 49.

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

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

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

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

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

4.2.3 Potential alternatives

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

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

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

4.2.4 Recommendations

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

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

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

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

LEI recommendations - Issue 2

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

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

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

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

In this section, LEI has reviewed the impacts of some of the key OEB policies and decisions associated with regulatory and rate-setting mechanisms enacted since 2006. In addition, LEI has discussed selected case studies where regulators in other jurisdictions responded to changes in regulatory mechanisms.

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

4.3.1 Status quo

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

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

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

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

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

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

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

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

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

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

Electricity distributors' DVA review initiative

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

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

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

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

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

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

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

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

[155] Ibid.

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

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

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

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

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

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

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

Renewed regulatory framework for electricity ("RRFE")

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. **Planning:** Distributors are required to file 5-year capital plans to support their rate applications. Planning is integrated to pace and prioritize capital expenditures, including smart grid investments.
3. **Measuring Performance:** The OEB proposed developing standards and measures that link directly to the performance outcomes. Using a scorecard approach, distributors are required to report annually on their key performance outcomes. As of April 2024, the OEB publishes 20 performance measures (updated annually) in areas related to customer focus, operational effectiveness, public policy and responsiveness, and financial performance.[166] However, the performance targets set by OEB are not yet linked to financial incentives and penalties for the distributors.

Figure 16. Comparison of three IR mechanisms provided by OEB

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

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

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

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

Rate design for electricity distributors (residential customers)

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

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

Rate design for commercial and industrial electricity customers

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

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

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

[169] Ibid.

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

[171] Ibid.

[172] Ibid.

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

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

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

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

Framework for energy innovation: distributed resources and utility incentives

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

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

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

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

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

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

[175] Ibid.

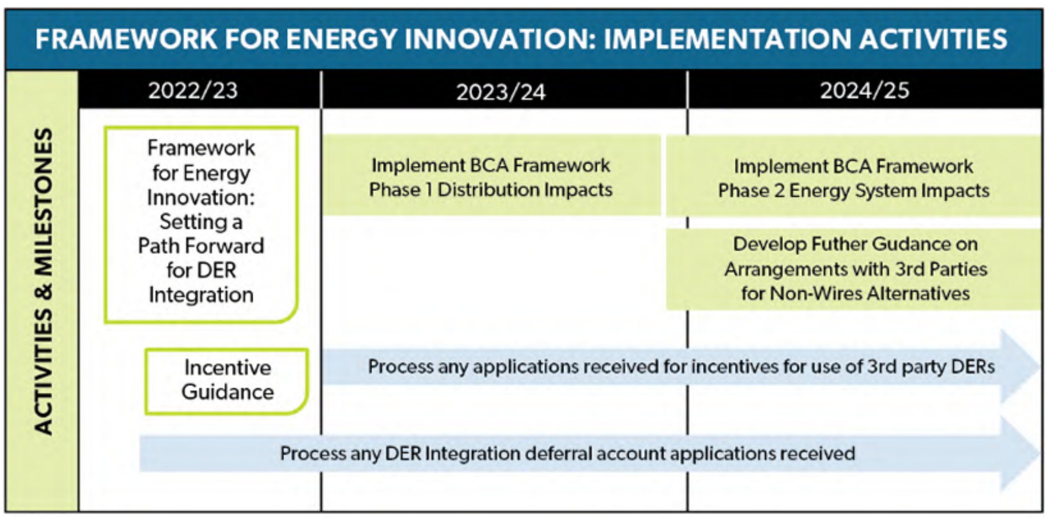
expected to be completed by the end of the 2023/24 fiscal year (the OEB outlined the methodology in a May 2024 report), followed by a second phase focused on the broader energy system impacts by the end of the 2024/25 fiscal year.

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

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

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

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



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

4.3.2 Relevant jurisdictional/literature review

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

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

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

DBRS

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

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

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

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

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

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

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

S&P Global

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

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

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

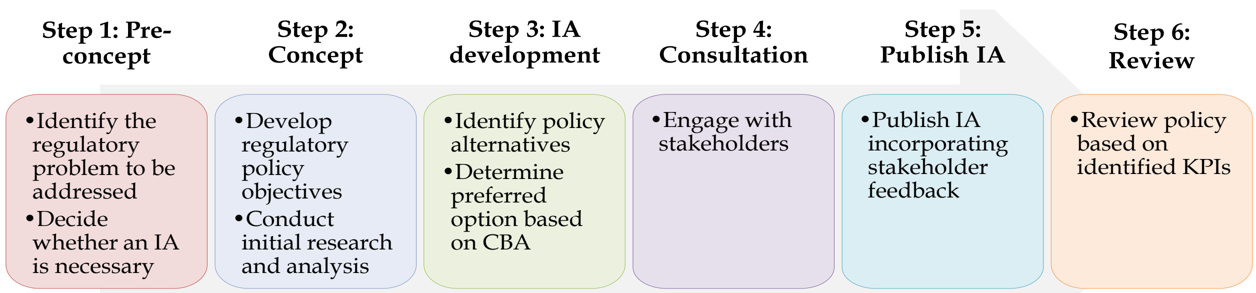
[181] Ibid.

United Kingdom

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

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

Figure 18. Ofgem's indicative Impact Assessment process



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

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

4.3.3 Potential alternatives

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

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

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

4.3.4 Recommendations

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

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

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

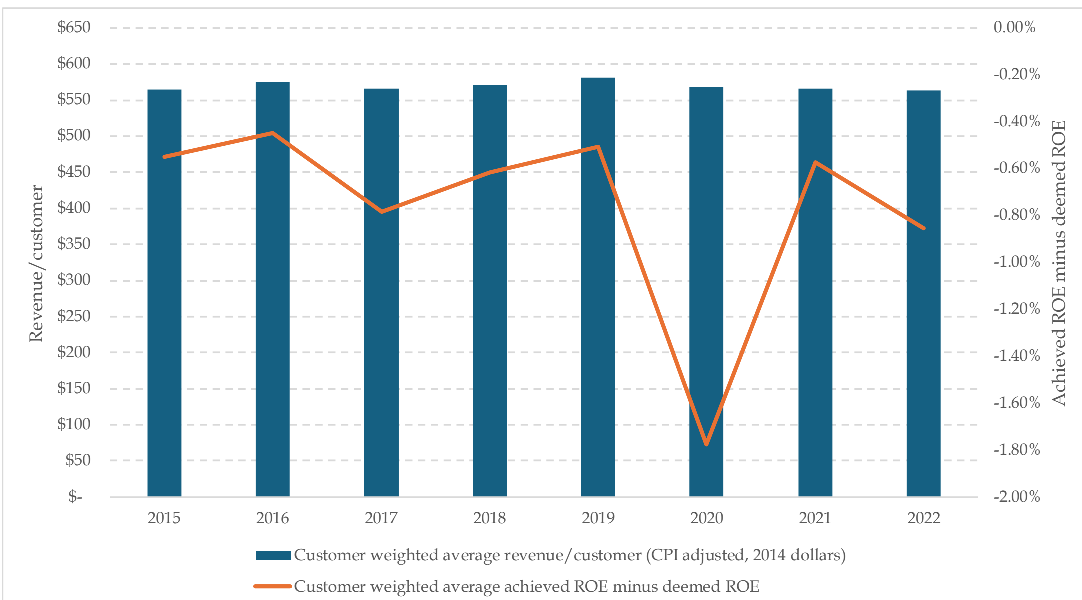
[182] In response to the OEB's interrogatory 1B-STAFF-93, Toronto Hydro withdrew its request for a custom labour component for the inflation factor. However, Toronto Hydro had the option to justify its proposal for a custom I factor.

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

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

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

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



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

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

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

As noted by OEB in 2009, most risk factors (including regulatory risks) tend to be stable over time. Thus, considering their impacts at pre-defined intervals is administratively inefficient and unnecessary. LEI recommends that the OEB's current policy (reviewing business/financial risk factors if there is a significant change from the status quo) be retained, with proactive IAs for following material changes.

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

4.4 Short-term debt rate – appropriateness of existing methodology

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

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

4.4.1 Status quo

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

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

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

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

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

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

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

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

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

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

1. The company stock is publicly traded in a recognized North American stock exchange; and
2. A certain percentage of the company's revenue or assets are from operations related to particular sectors:

    a. For generation peer companies, at least 70% from electricity generation
    b. For wires peer companies, at least 70% from electricity transmission /distribution
    c. For natural gas peer companies, at least 80% from natural gas transmission/distribution.

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

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

Figure 37. Determination of DCF ROE for electricity generation, wires (electricity transmission/distribution) and gas transmission/distribution

Generation			
Company	**Dividend yield (Apr 2023 - Mar 2024)**	**2024-2026 annual EPS growth estimate**	**DCF ROE**
Boralex Inc. (TSX:BLX)	2.1%	5.9%	7.9%
Constellation Energy Corporation (NASDAQGS:CEG)	0.7%	13.2%	13.8%
NRG Energy, Inc. (NYSE:NRG)	2.0%	3.6%	5.6%
Ormat Technologies, Inc. (NYSE:ORA)	0.7%	15.3%	16.0%
Vistra Corp. (NYSE:VST)	0.9%	13.4%	14.3%
Average	**1.26%**	**10.26%**	**11.52%**

Wires (electricity transmission and distribution)			
Company	**Dividend yield (Apr 2023 - Mar 2024)**	**2024-2026 annual EPS growth estimate**	**DCF ROE**
Ameren Corporation (NYSE:AEE)	3.7%	6.1%	9.8%
Consolidated Edison, Inc. (NYSE:ED)	3.4%	5.1%	8.5%
Edison International (NYSE:EIX)	4.1%	8.7%	12.8%
Eversource Energy (NYSE:ES)	4.7%	5.5%	10.1%
Exelon Corporation (NASDAQGS:EXC)	3.9%	5.4%	9.4%
FirstEnergy Corp. (NYSE:FE)	4.2%	6.5%	10.7%
Hydro One Limited (TSX:H)	3.1%	6.1%	9.2%
National Grid plc (LSE:NG.)	5.0%	6.2%	11.2%
NorthWestern Energy Group, Inc. (NASDAQGS:NWE)	5.0%	8.1%	13.1%
Average	**4.12%**	**6.41%**	**10.53%**

Gas distribution			
Company	**Dividend yield (Apr 2023 - Mar 2024)**	**2024-2026 annual EPS growth estimate**	**DCF ROE**
AltaGas Ltd. (TSX:ALA)	3.9%	10.3%	14.2%
Atmos Energy Corporation (NYSE:ATO)	2.7%	8.0%	10.7%
Chesapeake Utilities Corporation (NYSE:CPK)	2.3%	9.0%	11.3%
Enbridge Inc. (TSX:ENB)	7.3%	5.7%	13.0%
New Jersey Resources Corporation (NYSE:NJR)	4.0%	4.3%	8.2%
Northwest Natural Holding Company (NYSE:NWN)	5.1%	3.5%	8.5%
ONE Gas, Inc. (NYSE:OGS)	4.1%	3.1%	7.2%
RGC Resources, Inc. (NASDAQGM:RGCO)	3.9%	7.9%	11.8%
Spire Inc. (NYSE:SR)	4.8%	5.3%	10.2%
Average	**4.22%**	**6.34%**	**10.56%**

Note: LEI has excluded some outlier companies from the generation peer group due to very high or very low 2024-2026 annual EPS growth estimates that resulted in implausible estimates of DCF ROE for the generation peer group. The excluded companies include Brookfield Renewable Corporation, Clearway Energy, Inc., Innergex Renewable Energy Inc., Northland Power Inc., and TransAlta Corporation. Others, such as Talen Energy, lacked sufficient historical data.

Source: S&P Capital IQ.

To determine a uniform ROE for all OEB-regulated entities, LEI assigned weights (to estimates above) based on the sector's respective share of the 2022 rate base for the OEB-regulated entities.

For example, the 'electricity transmission and distribution' sector's share of the rate base relative to the total rate base across the three regulated sectors is 55%.

This approach resulted in a weighted average DCF ROE of 10.77% (as presented in Figure 38 below).

Figure 38. Determination of uniform DCF ROE for OEB-regulated entities

Utility industry sector	Share of 2022 rate base in Ontario	DCF ROE
Electricity transmission and distribution	55%	10.53%
Electricity generation	24%	11.52%
Natural gas distribution	22%	10.56%
Weighted average DCF ROE		**10.77%**

3. Same as #1 but determination of adjustment factors using multivariate regression analysis

The OEB (based on participant submissions in EB-2009-0084) determined the LCBF adjustment factor and the utility bond spread adjustment factor independently using distinct regression analysis. However, the credit spreads and central bank interest rates (which affect government bond yields) are intrinsically linked.[309] In the short run, a rise in Treasury rates is associated with declining credit spreads. However, a rise in Treasury rates may increase credit spreads in the long run. As such, it is reasonable to consider the impacts of BoC bond yields and corporate bond spreads on allowed ROEs within the same regression equation.

Considering the two variables simultaneously (the weighted average ROEs allowed by US regulators for electric and gas utilities as the dependent variable; 30-year US Treasury bond yields and Moody's seasoned Baa corporate bond yields as independent variables) using multivariate regression analysis lowers the adjustment factors for each variable, i.e., 0.26 for the LCBF adjustment factor and 0.13 for the utility bond spread adjustment factor. The multivariate regression analysis performed by LEI had an R squared value of 0.61, which indicates that a reasonably high amount of variance in the dependent variable (allowed ROEs) has been explained by the variance in dependent variables since 2001.

4. Determination of base ROE and annual adjustment of ROE using CAPM

The ROE with CAPM is estimated through the following formula:

Return on equity = risk-free rate + (beta x market risk premium) + additional risk premium (optional)

where:

- the *risk-free rate* measures a return available on an investment that is guaranteed and is uncorrelated with risky investments in a market;

309 Charles S. Morris & Robert Neal & Doug Rolph, 1998. "Credit spreads and interest rates : a cointegration approach," Research Working Paper 98-08, Federal Reserve Bank of Kansas City.

4.11.4 Recommendations

LEI believes that the OEB's existing cost of capital regime (including the determination of deemed capital structure) appropriately considers investor perspectives, as market data included in the formula and risk assessment when determining the appropriate equity thickness, when considered appropriately, should reasonably reflect investors' perspectives. The OEB can slightly modify the reporting requirements to enable better monitoring of the actual utility cost of capital (discussed in detail in Section 4.14).

LEI recommendation - Issue 11

- The OEB's current approach to cost of capital determination (including the determination of deemed capital structure) sufficiently considers investor perspectives, i.e., the allowed cost is commensurate with the perceived risks associated with the sector.
- LEI believes that the existing approach meets the FRS.

4.12 Capital structure – setting capital structure in accordance with the FRS

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

4.12.1 Status quo

The OEB's policy/guidelines *assume that the base capital structure will remain relatively constant over time* and require undertaking a full reassessment of a utility's capital structure only in the event of significant changes in the company's business and/or financial risk.[344]

As such, the OEB sets a uniform ROE for all regulated entities, and it increases the equity thickness in the capital structure if it assesses that an entity's business and financial risks have increased relative to the previous assessment. On the other hand, the allowed equity thickness can be reduced if OEB assesses that the business and financial risks for a regulated utility has decreased significantly.

As described in Section 4.2, business and financial risks are risks related to uncertainty surrounding a company's operating earnings and ability to finance its investments. The AUC defines business risk as follows: *Business risk represents the perceived uncertainty in future operating earnings before the impact of financial leverage (EBIT) and, hence, determines the capacity for a business to be financed with debt as opposed to equity.*[345] Financial risks are primarily linked to a company's

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

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

ability to continue to finance its capital needs and growth opportunities by attracting investors at reasonable terms.

The key business and financial risks considered by the OEB in recent equity thickness proceedings are discussed earlier in Section 4.2. Meeting the FRS is a key consideration in these proceedings. For instance, if the OEB concludes that the risk profile of a utility has increased, it increases the allowed equity thickness commensurate with increased risk. With respect to the three regulated sectors:

- In 2006, the OEB set the deemed capital structure at 60% debt and 40% equity for all ***electricity distributors and transmitters***. The capital structure is set on a case-by-case basis for other regulated entities.

- ***OPG***'s equity thickness was set at 47% between 2008 and 2014. This was reduced to 45% in 2014 and has remained unchanged since then.

- ***Enbridge Gas***' equity thickness was approved at 36% between 2006 and 2023. The OEB recently approved an increase in Enbridge Gas' equity thickness to 38%, applicable for 2024 rates. ***EPCOR Natural Gas***' equity thickness of 40% has remained unchanged since 2006.

4.12.2 Relevant jurisdictional review

LEI examined the processes of determining the deemed equity ratio in Alberta, Australia, and the UK.

Alberta

The AUC is required to *determine a fair return on the deemed equity component of invested* capital (i.e. the deemed equity ratio) to satisfy the FRS.[346] It adjusts deemed equity ratios to recognize risk differentials among utilities that have a uniform approved ROE.

The AUC uses credit rating targeting in the A-range as one of the major factors to determine the deemed equity ratio. It acknowledges the importance of maintaining an A-range credit rating for utilities, especially when interest rates rise, and considers that using the A-range credit rating target *respects the financial integrity, capital attraction, and comparability aspects of the [FRS].*[347]

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[346] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 44.

[347] AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 47.

Consequently, the AUC evaluates three credit metrics commonly used by credit rating agencies:[348]

1) **Earnings before Interest and Taxes ("EBIT") coverage:** calculated as EBIT divided by the sum of the return on debt amount and the interest on the CWIP balance, using the deemed debt ratio and the embedded average debt rate;
2) **Funds from Operations ("FFO") coverage:** calculated as the sum of the return on debt amount, the net income, and the depreciation divided by the sum of the return on debt amount and the interest on the CWIP balance, using the deemed debt ratio and the embedded average debt rate; and
3) **FFO/debt:** calculated as the sum of the net income and the depreciation divided by the sum of the deemed mid-year debt for rate base and CWIP.

The AUC then performs a sensitivity analysis to evaluate the effect of a range of equity ratios on the three credit metrics to arrive at the deemed equity ratios.

Australia

The AER determines the deemed gearing ratio (i.e. the deemed debt ratio) based on a benchmarking approach that examines relevant empirical evidence. The empirical estimation of the benchmark gearing ratio is based on five comparators' gearing ratios calculated using market values of equity and book value of debt since 2006.[349] The set of comparator companies consists of five listed Australian NSPs with data going back to 2006. Although four of the five companies have been delisted in the recent five years, the AER does not exclude them from the comparator set, since their historical data can *still be useful* in its consideration.[350] The five-year average, ten-year average, and average since 2006 across the comparator companies are calculated separately.

The AER aims to satisfy the NEO and NGO principles. The AER notes that the approach for estimating the ratio *will contribute to achieving the NEO and NGO to the greatest degree*.[351] This is because the benchmarking approach *both provides an incentive for service providers to adopt efficient gearing structures and prevents exposing consumers to different gearing levels adopted by individual*

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

[349] The book value of debt is used as a proxy for the market value of debt. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

[350] AER. Rate of return instrument. Explanatory statement. February 2023. Page 92.

[351] AER. Rate of return instrument. Explanatory statement. February 2023. Page 84.

service providers,[352] and the empirical study is *also consistent with [AER's] estimation of equity beta and credit rating*.[353,354]

British Columbia

The BCUC is obligated to ensure the *approval of rates to meet the FRS*.[355] It considers four factors when determining the deemed capital structure:[356]

1) Compensation to shareholders for the business risks of the benchmark utilities (FEI and FBC);
2) The approach to addressing the financial risk differentials through adjusting the capital structure;
3) Financial flexibility where the benchmark utilities have spare borrowing capacity; and
4) Benefits of maintaining the current credit ratings of benchmark utilities.

The BCUC concluded in 2022 that FEI has been facing increased risks since 2013, and therefore, an increase in FEI's equity component is warranted. The BCUC agreed with FEI on the proposed deemed equity ratio of 45%. FEI proposed the deemed equity ratio of 45% based on authorized equity ratios of its US proxy groups and the target of maintaining an A-level credit rating.[357] FEI's independent expert endorsed FEI's proposed ratio and compared the weighted ROEs, equal to the authorized ROE multiplied by the deemed equity ratios, for FEI and companies in its proxy group. He concluded that the proposed ratio is justified by FEI's risk profile and market data.[358]

The BCUC concluded that the 45% deemed equity ratio *meets the comparable investment and capital attraction requirements* as the figure is premised on FEI's proxy group and supported by its assessment of FEI's business risk.[359] Also, the increase from the previous equity ratio of 38.5%, which has not been changed since 2013, to the current level of 45% *will maintain FEI's financial*

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352 The AER notes that all else being equal, variations in gearing levels lead to different rates of return and different prices across NSPs. Source: Ibid.

353 The AER notes that the gearing ratio can affect a company's leverage risk which can impact equity beta and be a factor for credit rating agencies to consider. Source: AER. Rate of return instrument. Explanatory statement. February 2023.

354 AER. Rate of return instrument. Explanatory statement. February 2023. Page 84.

355 BCUC. Decision and order G-236-23. Generic cost of capital proceeding (Stage 1). September 5th, 2023. Page 127.

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

357 FortisBC Utilities. BCUC generic cost of capital. Exhibit B1-8. FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC Utilities) evidence. January 31st, 2022.

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

359 Ibid. Page 134.

integrity.[360] The BCUC also concluded that a 45% equity component *forms an optimal capital structure based on the evidence* and provides sufficient financial leverage and flexibility.[361]

Similarly, the BCUC determined FBC's deemed equity ratio to be 41% using the same rationale which considered the FRS, business risk, comparable investments, credit rating, financial leverage, and financial flexibility.

A summary of jurisdictional review on approaches to setting deemed capital structure and the way they reflect the FRS (or similar standards) is shown in Figure 49.

Figure 49. Summary of the jurisdictional review (Issue 12)

Jurisdiction	Approach to determining deemed capital structure	How the FRS is reflected
Alberta	• Use the targeting of credit ratings in A-range by considering EBIT coverage, FFO coverage, and FFO/debt • Perform a sensitivity analysis to evaluate the effect of a range of equity ratios on the credit metrics and select the one ratio that leads to a credit rating in A-range with its own judgment	• The use of the A-range credit rating target is a factor that respects the financial integrity, capital attraction, and comparability aspects of the FRS
Australia	• Use a benchmarking approach based on comparator companies' gearing ratios calculated using market values of equity and book value of debt since 2006 • Compare the resulting average gearing ratios of the comparator set with the previous allowed gearing ratio • Conclude that the difference is not significant and hence continue using the previous ratio	• The benchmarking approach contributes to achieving the NEO and NGO to the greatest degree • The approach provides an incentive for service providers to adopt efficient gearing structures and prevent exposing consumers to different gearing levels • The empirical study is consistent with AER's estimation of equity beta and credit rating
BC	• Consider compensation to shareholders for the business risk • Compare the deemed equity ratio and the weighted ROE with a proxy group • Target an A-level credit rating • Consider financial leverage and flexibility	• The determined deemed equity ratio meets the comparable investment and capital attraction requirements as it is premised on the benchmark utility's proxy group and supported by the assessment of the business risk • An increased deemed equity ratio compared with the previous ratio ensures financial integrity

4.12.3 Potential alternatives

The OEB may consider the following options to set the deemed capital structure:

1. **Status quo:** set a uniform ROE and adjust the capital thickness if, upon application, the OEB assesses there is a meaningful change in business/financial risks.
2. **Set capital structure for each sector using rating agency benchmarks** for a desired rating given the established ROEs. This can be done using a forward-looking cash flow scenario analysis and assessing which capital structure will likely result in credit metric ratios needed for a particular rating.

[360] Ibid.

[361] Ibid.

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

4.12.4 Recommendations

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

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

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

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

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

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

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

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

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

[365] Ibid. Page 6.

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

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

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

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

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

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

[366] Ibid. Page 7.

[367] Ibid. Page 7.

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

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

LEI recommendation - Issue 12

- The OEB's current approach of revising the capital structure upon application if warranted due to increase in business/financial risks is a reasonable practice, as OEB has noted that risks rarely change meaningfully in a short period of time.
- LEI believes that the existing approach meets the FRS.
- Applicants should be required to include forward cash flow modeling and scenario analysis showing impact on credit metrics to support their case.

4.13 Capital structure – appropriate capital structure for single vs. multiple-asset transmitters

Issue 13: Should the OEB take a ***different approach for setting the capital structure*** for electricity transmitters depending on whether they are a ***single versus multiple asset transmitter***?

Ontario has eight licensed electricity transmitters.[370] As of 2022, Hydro One accounts for ~91% of the total approved rate base for electricity transmitters. However, the OEB allows the same equity thickness for all electricity transmitters. Issue 13 relates to whether the smaller size of the electricity transmitters (other than Hydro One) increases their risk profile relative to Hydro One, and whether that warrants a higher allowed equity thickness in the capital structure.

4.13.1 Status quo

The OEB stated in EB-2009-0084 that the capital structure for transmitters will be determined on a case by case basis.[371] However, the OEB has allowed a 40% equity thickness to all electricity transmitters (same as electricity distributors) since 2006.

4.13.2 Relevant jurisdictional review

Jurisdictions studied by LEI consider the implication of size differently when determining the deemed capital structure. The size of a utility directly impacts AUC's determination of equity thickness in Alberta only for one gas distribution entity but is not considered by the AER in Australia. In the UK, a single notional gearing is applied to all electricity transmitters, regardless of their size.

Alberta

The AUC sets a generic deemed equity ratio of 37% for all electric and gas transmitters with one exception of Apex Utilities Inc. ("Apex") which is a gas distribution company with a deemed

[370] OEB. List of licensed companies. Accessed on May 21st, 2024.

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

equity ratio of 39%.[372] For all electric transmitters of different sizes (rate bases) as shown in Figure 51, the AUC sets a uniform deemed equity ratio.

Figure 51. Electric and gas transmission companies regulated by the AUC

Electric transmitter	2023 Rate base ($millions)
AltaLink L.P.	7,361
ATCO Electric Transmission	5,796
ENMAX Power Corporation	788
EPCOR Distribution and Transmission Inc.	794
KainaiLink L.O.	32
PiikaniLink L.P.	47
TransAlta Corporation	54

Source: AUC. *Rule 005 report*. 2024.

Australia

The AER sets a single benchmark for all NSPs (which includes electric transmitters and distributors), regardless of the size, which, from the AER's perspective, is the best way to achieve the NEO and/or NGO. The single benchmark *prevents exposing consumers to different gearing levels adopted by individual service providers*.[373] The benchmarking approach includes latest market information and considers short-term and long-term outcomes *to the extent they reflect changing market conditions*.[374]

United Kingdom

Ofgem considers notional gearing *in light of the risks network companies face, rating agency views on gearing levels for investment grade regulated networks, balancing an appropriate cost of capital and the impact medium term market conditions have on debt servicing*.[375] Ofgem sets a notional gearing of 55% for all electric transmission companies and a notional gearing of 60% for National Grid Gas Transmission, regardless their varying sizes.

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[372] The upward adjustment is due to additional risks arising from *Apex's small size, geographically dispersed service territory in rural Alberta, and gas supply risk*. The higher equity ratio provides Apex with greater revenues to compensate for the inability to generate cost savings and efficiencies that stem from economies of scale. Also, the additional equity provides Apex with *a better opportunity to achieve higher interest coverage ratios while reducing the financial risk*, which helps Apex maintain its credit rating and meet the FRS. Source: AUC. Decision 27084-D02-2023. Determination of the cost-of-capital parameters in 2024 and beyond. October 9th, 2023. Page 62.

[373] AER. Rate of return instrument. Explanatory statement. February 2023. Page 84.

[374] AER. Rate of return instrument. Explanatory statement. February 2023. Page 95.

[375] Page 175.

Figure 52. Notional gearing ratio of transmission companies regulated by Ofgem

Utility	Notional gearing	2023 Regulatory asset value ($billions)
National Grid Electricity Transmission	55%	17.1
Scottish Power Transmission	55%	3.1
Scottish Hydro Electric Transmission	55%	4.8
National Grid Gas Transmission	60%	6.6 (2022)*

Source: Financial reports of the listed utilities.

A summary table of the jurisdictional review on the implication of the size of a utility is shown in Figure 53.

Figure 53. Summary of the jurisdictional review (equity ratio for transmitters of varying sizes)

Jurisdiction	Implication of size
Alberta	Electric transmitters of varying sizes are allowed the same equity ratio
Australia	A single benchmark equity ratio applied to all NSPs, regardless of their sizes
UK	A single notional gearing ratio applied to all electric transmitters, regardless of their sizes

4.13.3 Potential alternatives

The OEB may consider the following options:

1. **Status quo:** continue to allow the same equity thickness for all electricity transmitters; or
2. **Grouping electricity transmitters based on their risk profile**, considering size as a proxy for risk i.e., determining the capital structure for Hydro One separately and a slightly higher uniform capital structure for the other transmitters.

4.13.4 Recommendations

The reasoning provided by the OEB in 2006 to move away from the size-based capital structure determination (described in Section 4.12.4) for electricity distributors also applies to electricity transmitters. The risk profile of electricity transmitters is similar to, if not lower than, that of electricity distributors. As such, it is reasonable to consider the same approach to setting capital structures as electricity distributors.

Moreover, size is less of an issue for Ontario's electricity transmitters as transmitters have essentially one customer: IESO.[376,377] Variations in OM&A expenses are likely minor, and efficiencies can be achieved through contracting out. Transmitters (big and small) cannot diversify customer risk or economic risk but are likely insulated from volume risk based on their tariff structure. Many licensed transmitters are also part of larger entities (for example, B2M Limited Partnership and Hydro One Sault Ste. Marie LP are subsidiaries of Hydro One; Canadian Niagara Power Inc. is a subsidiary of Fortis Inc.). Further, similar to electricity distributors, allowing higher equity thickness for smaller transmitters may discourage the consolidation of smaller entities.

LEI, therefore, recommends that the OEB retain its approach of allowing a uniform deemed capital structure to all electricity transmitters.

LEI recommendation - Issue 13

LEI recommends that the current approach of allowing the same equity thickness to all electricity transmitters (and distributors) be maintained.

4.14 Mechanics of implementation – monitoring mechanism to test the reasonableness of the cost of capital methodology

Issue 14: ***What on-going monitoring indicators to test the reasonableness of the results generated by its cost of capital methodology should the OEB consider, including the monitoring of market conditions?***

This issue is strictly concerned with the OEB's ***ongoing monitoring*** of the cost of capital parameters/values; the issue of more comprehensive ***periodic reviews*** of the cost of capital policy as a whole is covered separately – specifically under Issue 17 in the Final Issues List (see Section 4.17).

4.14.1 Status quo

As described by OEB Staff, "*macroeconomic conditions and their impact on cost of capital are monitored throughout the year, and any major changes could trigger an updated calculation.*"[378] This ongoing monitoring process is conducted through quarterly reports that are prepared for internal review purposes only and thus are not released publicly. LEI has been retained by the OEB to prepare these quarterly reports since 2019. These quarterly reports comprise of two key analytical components:

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376 IESO. Introduction to the IESO Settlement Process. May 2023. Page 10.

377 Hydro One considers IESO the related party for all its regulated transmission revenues. Source: EB-2021-0110.

378 OEB. *OEB Staff Report: Review of the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084).* January 14, 2016. P. 4.

4.22 Cloud computing deferral account – appropriate carrying charges for cloud computing deferral account

Issue 22: ***Should carrying charges and/or another type of rate apply to the Cloud Computing deferral account?*** *If so, what rate should be applied?*

The OEB would like to determine if the risk profile of the transition to cloud computing solutions warrants an additional risk premium over and above the carrying charges, i.e., a higher rate than the prescribed interest rates, which is currently allowed to the cloud computing deferral account.[444] However, the OEB also noted that if the OEB determines that carrying charges other than the prescribed rates will apply to the account, any carrying charges that have accrued will be reversed in favour of the final approach.

4.22.1 Status quo

Effective December 1st, 2023, per the Accounting Order (003-2023), the OEB implemented a generic deferral account that records the incremental costs of cloud computing implementation. The recorded costs are subject to OEB's approval in the utilities' respective subsequent rate proceedings for each utility.[445] Incremental costs are costs outside of what is embedded in rates i.e. when amounts are recorded, they should represent impacts that are more than what utilities are already compensated for.[446]

Utilities are required to record incremental OM&A costs and incremental capital costs associated with cloud computing implementation separately. The disposition of recorded costs will be subject to review by the OEB in the utility's next rebasing (cost of service or Custom IR) rate proceeding.[447] The OEB will also allow utilities that are in an extended incentive rate-setting period (e.g. under a deferred rebasing period arising from utility consolidations or under Annual Incentive Rate-setting (IR) Index) to request significant account balances for disposition in a non-rate rebasing year to address potential intergenerational inequity concerns, if warranted. The OEB has stated that only *material* costs will be allowed to be disposed of and that materiality will be assessed at the project level.[448]

The period of cost recovery is intended to align with the initial term of the computing contract. However, the OEB has provided utilities flexibility to propose a different disposition period when they bring the account for disposition.[449] Carrying charges at the OEB's prescribed rates for DVAs

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

[445] Ibid.

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

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

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

[449] Ibid.

will apply to the account (unless otherwise directed by the OEB).[450]

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

4.22.2 Relevant jurisdictional review

Alberta is considering allowing the same return as the rest of the regulated asset base for operating costs associated with cloud-based solutions on a pilot basis. BC allows a return equal to the weighted average cost of actual debt on the 'Cloud Costs Regulatory Account'. NY allows utilities to capitalize cloud-based software services to their regulated rate base.

Alberta

The AUC recognizes that IT service providers are moving towards cloud-based solutions, the cost of which may not be capitalized, and that the solutions replace traditional IT products that were previously capitalized. For the purpose of incentivizing distribution utilities to achieve least-cost solutions and minimize any capital bias, which ultimately provides a *long-term benefit to ratepayers by lowering costs in situations where operating solutions are more cost-effective than capital solutions*, the AUC accepts applications from distribution utilities to *earn a return on operating solutions on a pilot basis* during the PBR3 term.[451] The AUC is *interested in exploring* elements of a deemed capital additions approach recommended by ENMAX Power Corporation ("ENMAX"), over the PBR3 term.[452,453] The deemed capital additions approach includes variations on payment terms and recovery of costs as illustrated in Figure 56 below. As such, the AUC stated that it will consider applications from distribution utilities to earn a return on operating solutions on a pilot basis.

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

[451] AUC. Decision 27388-D01-2023. 2024-2028 Performance-based regulation plan for Alberta electric and gas distribution utilities. October 4th, 2023. Page 74.

[452] Ibid.

[453] LEI was the consultant to ENMAX in the PBR3 proceeding.

Figure 56. Options with deemed capital additions approach

Approach	Payment terms	Return on expenditure	Amortization
Pre-paid or partially pre-paid	Contract pre-paid or partially pre-paid	Same return as rest of regulated asset base	At end of PBR term, unamortized part of contract would be included in subsequent PBR term's regulated asset base
Partial-amortization	Contract paid annually	Same return as rest of regulated asset base	Amortization is enabled until the end of the contract
Margin-based	Contract paid annually	Fixed adder	N/A

Source: AUC. Decision 27388-D01-2023. 2024-2028 Performance-based regulation plan for Alberta electric and gas distribution utilities. October 4th, 2023. Page 73.

A distribution utility must apply on a per-project basis. The application must relate to a scope of work not covered by an existing arrangement and replace a corresponding capital solution. The utility is required to demonstrate the reasonableness of the proposed operating costs.[454]

British Columbia

In November 2022, British Columbia Power Authority ("BC Hydro") filed an application with the BCUC seeking approval of the Cloud Costs Regulatory Account which would record: 1) variances between the forecast and actual Cloud Arrangements implementation operating costs (i.e. one-time, upfront implementation costs), and 2) variances between forecast and actual unplanned annual usage fee for Cloud Arrangements.[455]

With respect to the implementation operating costs, BC Hydro noted that IFRS requires the costs to be recognized as operating expenses in the year they are incurred, rather than being recovered over the life cycle. *As the implementation costs were not planned as operating costs, BC Hydro would not recover the actual implementation operating costs from ratepayers in the absence of the Cloud Costs Regulatory Account*.[456]

Similarly, under IFRS, annual usage fees are also recognized as operating expenses when incurred. Since Traditional Computing does not consider annual usage fees for forecast IT projects, when an IT project is initially planned as Traditional Computing but is later determined to be a Cloud Arrangement, the incremental annual usage fees would not be recovered from ratepayers in the absence of the Cloud Costs Regulatory Account.[457]

In April 2023, the BCUC approved the deferral of these costs and directed BC Hydro to establish separate deferral accounts for the costs. Specifically, the BCUC approved:[458]

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[454] AUC. Decision 27388-D01-2023. 2024-2028 Performance-based regulation plan for Alberta electric and gas distribution utilities. October 4th, 2023. Page 74.

[455] BCUC. Order G-85-23. Application of approval of cloud costs regulatory account. April 18th, 2023.

[456] Ibid. Appendix A. Page 2.

[457] BCUC. Order G-85-23. Application of approval of cloud costs regulatory account. April 18th, 2023.

[458] Ibid. Page 3.

1) The establishment of the Cloud Costs Regulatory Account, *attracting interest at BC Hydro's weighted average cost of debt*, to defer the forecast Cloud Arrangements implementation operating costs and the variance between forecast and actual Cloud Arrangements implementation operating costs as an intangible asset, and to amortize the forecast Cloud Arrangements implementation operating costs over the remaining life cycle for each implementation; and
2) The establishment of a separate regulatory account for Cloud Arrangements annual usage fees, *attracting interest at BC Hydro's weighted average cost of debt*, to defer any variance between the actual annual usage fees for unplanned Cloud Arrangements and the cost-saving related to forecast maintenance and support costs associated with the planned Traditional Computing capital project, and to amortize the annual usage fee variances over the next Revenue Requirement Application[459] ("RRA") test period.[460]

New York

In May 2016, the NYPSC issued a declaratory statement in its Reforming the Energy Vision ("REV") Track 2 Order, which enables utilities to capitalize cloud-based software services. Many businesses have found it *more efficient to enter contracts to lease software services over extended periods*, rather than developing their own software.[461] When pre-paying the total cost of a service contract, a utility can record the unamortized balance of the pre-payment as a regulatory asset, to be included in its rate base and earn a return.[462]

A summary of the jurisdictional review is shown in Figure 57 below.

[459] RRA is an application including various approvals sought by BC Hydro from the BCUC, such as approval of rates, revisions to or request for new regulatory accounts, the setting of depreciation rates, approval of expenditure schedules, etc. Source: BC Hydro. Revenue requirements. Accessed May 27th, 2024.

[460] BCUC. Order G-85-23. Application of approval of cloud costs regulatory account. April 18th, 2023. Page 3.

[461] New York Public Service Commission. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (Case No. 14-M-0101).* May 19, 2016. Page 104.

[462] Ibid.

Figure 57. Summary table of the jurisdictional review on Issue 22

Jurisdiction	Cloud computing accounting treatment
Alberta	• The AUC accepts applications from distribution utilities to earn a return on operating solutions on a pilot basis during the PBR3 term • The return is determined using the deemed capital additions approach with three options: pre-paid or partially pre-paid, partial amortization, and margin-based • A distribution utility must apply on a per-project basis • The proposal must relate to a scope of work that is not covered by an existing arrangement and replace a corresponding capital solution
BC	• The BCUC directed BC Hydro to establish separate deferral accounts, earning an interest at BC Hydro's weighted average cost of debt, for o Cloud Arrangements implementation operating costs: amortized over the remaining life cycle of each implementation o Cloud Arrangements annual usage fees: amortized over the next RRA test period
NY	• The NYPSC allows a utility to record the unamortized balance of the pre-payment of cloud-based solutions as a regulatory asset which is included in its rate base and earn a return

4.22.3 Potential alternatives

The OEB may choose from one of the following options:[463]

1. Status-quo approach; and
2. Allow carrying charge based on deemed WACC for the unamortized portion of the cloud computing contract.

1. Status-quo approach

The OEB may continue to apply the prescribed interest for DVAs to the cloud computing deferral account, i.e., the same allowed carrying charge/interest rate as other DVA accounts.

2. ***Allow carrying charge based on deemed WACC for the unamortized portion of the cloud computing contract***

Under this approach, the OEB can allow the prescribed interest rate for the DVAs on the incremental operating costs. The recorded incremental operating costs and the relevant costs allowed during IRM proceedings (if any) can be treated as *amortized* costs of the cloud computing contract. The OEB can treat the balance *unamortized* portion of the cloud-based contracts (contract

[463] LEI has not presented the margin-based fixed adder option (described in Figure 46) as an alternative due to additional complexities associated with determining an appropriate margin each year and incompatibility with the prevailing Ontario practice of recording incremental costs in a cloud computing deferral account. However, LEI is broadly supportive of such an approach for "capital as a service".

value minus amortized costs) as deemed capital additions to incentivize the transition to cloud-based software solutions. The onus should be on the utilities to justify the claimed costs during rebasing.

A deemed WACC (based on allowed capital structure, ROE, DLTDR and DSTDR, and determined as of the year of rebasing or the year of disposition, for the remaining term of the contract) for all utilities may be allowed on the deemed capital additions.[464] In addition, if the recorded incremental capital costs are not yet capitalized, the OEB may consider allowing the prescribed interest rate for the CWIP account on the recorded incremental capital costs until it is capitalized and added to the rate base.

The associated costs can be added to customer rates during the disposition of recorded costs.

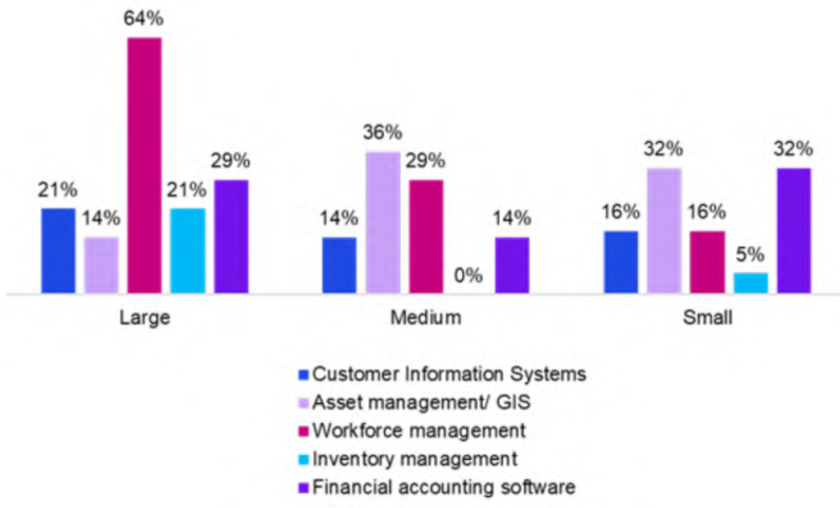
4.22.4 Recommendations

Changes in technology and industry structure have created the possibility that activities previously enabled by capital investment can be provided through contractual arrangements. However, utilities are disincentivized from pursuing such arrangements because doing so removes activities on which the utility earns a return from the rate base and treats them as operating expenses on which they do not earn a return. LEI believes that cloud computing is less risky compared to in-house investments, however, a deemed WACC is necessary as a means of aligning incentives for utilities to transition to cloud computing solutions.

This can act as a barrier to transition to cloud computing solutions despite being more cost effective over a longer time horizon. The increased risks of transition to cloud-based solutions are associated with foregone revenue from the capital investments in in-house server solutions. This reluctance to transition is reflected in the share of Ontario utilities that have transitioned to cloud-based solutions (see Figure 58).

[464] For example, if the cloud computing deferral account is brought forward for disposition in a non-rebasing rate year, LEI recommends that the ROE, DLTDR and DSTDR applicable for the year of disposition may be utilized to determine the deemed WACC.

Figure 58. Adoption of cloud-based solutions by OEB-regulated utilities



Source: OEB. Appendix B to Accounting Order (003-2023). KPMG Report on regulatory options for the treatment of cloud computing costs. September 2023. Page 26.

LEI recommends that the OEB employ a deemed capital additions approach (Alternative #2 in Section 4.22.3) to increase utility flexibility and align incentives with customers. This approach will be beneficial in reducing a utility's capital bias as the utility will theoretically earn the same return if it were making capital investments in in-house IT infrastructure. The LEI recommendation is intended to be applied as a default procedure in circumstances where the utilities have not specifically referenced cloud computing in their previous rebasing applications. This should not prevent the utilities from proposing an alternate regulatory treatment for OEB's consideration when filing rebasing applications. Similar approaches can be used for other capital as a service arrangements.

LEI recommendation – Issue 22

- LEI believes a deemed WACC is necessary as a means of aligning incentives for utilities to transition to cloud computing solutions
- LEI recommends that the OEB employ a deemed capital additions approach, which allows deemed WACC on the unamortized portions of the cloud computing contracts.

Consumers Council of Canada Interrogatory #N-M1-9-CCC-4

Interrogatory

Reference:

Exhibit M1, page 97

Preamble:

At page 97, LEI notes that, on average, the actual debt ratio for Ontario LDCs is lower than the deemed ratio of 60%. However, the customer-weighted average debt ratios are meaningfully higher than the simple average, which indicates that the capital structure of larger utilities is closer to the deemed capital structure, while smaller utilities finance more of their rate base with equity.

Question(s):

a) Please confirm that in the customer-weighted debt ratio analysis, Ontario LDCs have a lower actual debt ratio than the deemed ratio.

b) Please provide any insight that LEI may have as to why the simple average actual debt ratio and customer-weighted average actual debt ratio are lower than the deemed ratio for Ontario electricity distributor.

c) Please provide any insight that LEI may have regarding why smaller LDCs finance more of their rate base with equity relative to larger LDCs.

d) Please advise whether the overall LDC trend of funding more of rate base with equity (relative to the deemed amounts) provides any insight into a LDC's shareholders' views on earning only the debt rate on, at least a portion of, its invested equity capital.

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

a) Yes, confirmed.

b) Capitalization approaches vary by utility and are appropriately left to management discretion. Companies may choose by effectively self-funding a portion of their debt to simplify their lending relationships or provide additional flexibility regarding coverage ratios and other bank covenants which may interfere with company decisions with regards to distributions (dividends).

c) Shareholders of smaller utilities tend to be municipalities who are more comfortable informally self-funding the debt portion of the deemed capital structure either because the debt return is acceptable or to increase flexibility with regards to distributions as noted in b) above.

d) Please see answers to b) and c) above.

Consumers Council of Canada Interrogatory #N-M1-5-CCC-6

Interrogatory

Reference:

Exhibit M1, page 118

Question(s):

For each company in each proxy group listed in Exhibit M1 at page 118, please provide a table that includes the following information (if available and as applicable):

a) Company name

b) Credit rating

c) S&P business risk rating

d) S&P financial risk rating

e) Percentage of operating income from, as applicable, electricity distribution, electricity transmission, electricity generation, natural gas operations

f) Percentage of operating income, as applicable, by operating area (i.e., electricity distribution, transmission, generation or natural gas operations) that is regulated

g) Percentage of overall operating income that is regulated

h) Beta information:
   i. Raw beta
   ii. Beta used by expert in CAPM calculation

i) The regulatory agency that regulates the company (i.e., OEB, AUC, CPUC, etc.) and the applicable rating as set out in the "Utility Regulatory Jurisdiction Assessment performed by S&P Global" (see p. 129 of Exhibit M1 – LEI Expert Report)

j) Description of ratemaking approach applied to the company. As part of this response, please include information regarding:
   i. Most prevalent form of ratemaking (e.g., cost of service, cost of service plus IRM, etc.)
   ii. Application of a forward test year approach in cost of service ratemaking

iii. Availability of Custom IR option (which, as applied in Ontario, allows for multi-year (typically 5 years) recovery of approved capital budgets as proposed by the utility)
iv. Availability of mechanisms that allow the recovery of incremental capital between rebasing proceedings (and a description of how those mechanisms operate)
v. Reliance on fixed vs. variable rates (by rate class)
vi. Availability of deferral and variance accounts for non pass-through costs and revenues (and the types of accounts that are available)
vii. Availability of Z-factor relief (and the types of relief available through this mechanism)
viii. Availability of off-ramp provisions when actual ROE falls below a certain threshold

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

Figure 39 in the LEI Report already provides relevant information. Providing the detailed information requested here is unnecessary to support LEI's conclusions.

School Energy Coalition Interrogatory #N-M1-10-SEC-18

Interrogatory

Reference:

Exhibit M1, page 120

Question:

LEI notes, that it does not believe a CAPM ROE based on Canada market data is appropriate as compared to US MRP. Please provide a CAPM ROE calculation weighted 72/25 (Canada and US), 50/50 (Canada/USA), 25/75 (Canada/US).

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

CAPM ROE based on weights of 75/25 (Canada and US), 50/50 (Canada/USA), 25/75 (Canada/US) would result in ROE of 6.13%, 7.10%, and 8.07%, respectively.

As noted in the LEI report: *"LEI believes that CAPM ROE based on Canadian market data (5.14%) does not reflect investors' expected equity returns. The eight major pension funds in Canada (informally known as the Maple 8) allocate only about 25% of their portfolio to domestic Canadian investments, which indicates that investors are more likely to consider their MRP opportunity costs based on the US MRP.*[17,18] *As such, LEI prefers CAPM determined using US MRP."*

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

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

School Energy Coalition Interrogatory #N-M1-6-SEC-16

Interrogatory

Reference:

Exhibit M1, page 89

Question:

The OEB's DLTDR is a forecast based on information regarding 30-year bond rates. Ontario utilities often issue debt (either by way of bond or other debt instruments) with different terms (e.g. 5, 10, 15, or 20 years).

a) Does LEI believe that the current and its proposed revision to the methodology in setting the DLTDR reflects a proxy for interest rate for terms less than 30 years? If so, please explain.

b) Does LEI believe there is merit in determining multiple DLTDRs reflecting different terms of debt?

c) Regardless of the answer to part (b), if the OEB were to determine multiple DLTDRs based on the term of the debt, please provide recommendations regarding the methodology.

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

a) Bonds with longer maturities generally have higher interest rate risk than similar bonds with shorter maturities.[16] As LEI recommends that DLTDR be applied as a cap, LEI believes that DLTDR acts as an appropriate proxy regardless of the composition of debt maturities.

b) No.

c) If the OEB were to determine multiple DLTDRs based on the term of the debt, it may consider the yield of the closest sovereign bond term as a proxy (plus a spread based on credit profile). However, as highlighted above, LEI believes such a methodology would not add meaningful value to the DLTDR estimate.

[16] U.S. Securities and Exchange Commission. Interest rate risk — When Interest rates Go up, Prices of Fixed-rate Bonds Fall. Accessed on August 11th, 2024.

School Energy Coalition Interrogatory #N-M1-3-SEC-11

Interrogatory

Reference:

Exhibit M1, page 63

Question:

LEI has outlined a number of OEB regulatory/policy changes since 2006. Appendix A to these interrogatories outlines a number of additional OEB regulatory/policy changes since 2014. For each, please provide LEI's view on how each would impact utility business and financial risk.

Appendix A
Additional OEB Regulatory Policy Changes (Over the Last 10 Years)

i Introduction of Advanced Capital Module (ACM). See Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (September 18, 2014)

ii MAAD transaction deferred rebasing lengthened from 5 to up to 10 years, at discretion of utility. See Report of the Board Rate-Making Associated with Distributor Consolidation (March 26, 2015)

iii OEB requiring residential customers to be billed on a monthly basis (previously many were bi-monthly). See Distribution System Code (DSC) Amendments (April 15, 2015). Related, reduced billing lag as demonstrated by OEB's reduction in default working capital from 13% to 7.5%. See OEB Letter, Allowance for Working Capital for Electricity Distribution Rate Applications, June 3, 2015)

iv Reduction of ACM/ICM deadband from 20% to 10%. See Supplemental Report: New Policy Options for the Funding of Capital Investments (Jan 22, 2016)

v Expansion of eligibility for ICM for utilities on deferred rebasing period. See OEB Letter Re: Incremental Capital Modules During Extended Deferred Rebasing Periods (Feb 10, 2022)

vi Annual update to LV Rates through IRM/rate adjustment process, whereas previously only updated at rebasing. See Updated Filing Requirements for Electricity Distribution Rate Applications, Chapter 3 (June 15, 2023)

vii UTRs issued earlier in year allowing for more up to date RTSRs included in annual rate adjustments applications. See OEB Letter, 2024 Preliminary Uniform Transmission Rates and Hydro One Sub Transmission Rates (September 28, 2023)

viii Introduction of OEB NWS Guidelines which provides opportunities for utilities during IRM (or even in circumstances existing Custom IR plan) to seek additional funding opportunities for non-wires solutions. See Non-Wires Solutions Guidelines for Electricity Distributors (March 28, 2025)

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

LEI was asked by the OEB to review major policy changes only. It is notable that ICM/ACM is a cross-cutting theme in several policy changes identified in the question. ICM was also reiterated in the "Renewed Regulatory Framework for Electricity ("RRFE") Distributors" report, which is already covered in Section 4.3 of the LEI Report. LEI's view is that the ACM can be viewed as an extension of the OEB's RRFE report.

Windsor Canada Utilities Ltd. Outlook Revised To Stable From Negative On Regulatory Developments; Ratings Affirmed

- After further evaluation of the Ontario Energy Board's (OEB) regulatory construct for Windsor Canada Utilities Ltd. (WCU), we affirmed our 'A' issuer credit rating on WCU and revised the outlook to stable from negative.
- We also affirmed our 'A' rating on WCU's senior unsecured debt.
- Our evaluation reflects that OEB has proactively addressed regulatory lag. We now believe that WCU will maintain consistent financial measures sufficient for the ratings.
- The stable outlook reflects our view of Ontario's supportive regulatory framework and our expectation that WCU's funds from operations (FFO) to debt will be 17%-21% across our outlook period.

TORONTO (S&P Global Ratings) June 18, 2024—S&P Global Ratings today took the above rating actions.

Our evaluation of OEB's regulatory construct, which reduces regulatory lag, strengthens WCU's ability to recover transmission costs on a timely basis. During 2023, OEB proactively addressed regulatory lag, particularly with the timely recovery of rising transmission-related costs. Regulatory lag is the timing difference between when costs are incurred by local distribution companies (LDC) and ultimately recovered from ratepayers. Previously, regulatory lag in Ontario was about 24 months, materially weakening the financial measures of most Ontario LDCs, given increasing inflation and rising transmission capital spending.

However, beginning in 2024, OEB allowed LDCs to implement new preliminary transmission rates at about the time it authorizes them, significantly reducing the risk of regulatory lag. Overall, we view OEB's proactiveness to quickly address this regulatory lag as constructive and consistent. We expect WCU's management of regulatory risk and financial measures will be more consistent.

We continue to assess WCU's financial risk profile as intermediate. WCU's financial performance weakened such that FFO to debt was slightly above 11% in 2022, reflecting regulatory lag related to higher transmission costs. In 2023, this improved to 20.4%. Our base case expects FFO to debt to remain in the range of 17%-21% through 2026. As WCU recovers some transmission cost increases from prior years, FFO to debt will remain temporarily elevated at about 20% through 2025. Thereafter, we expect it to gradually moderate to about 17%.

Our forecast assumes capital spending of about C$20 million-C$25 million and dividends of about C$4 million annually. We assess the financial risk profile using our low-volatility financial benchmark table, which reflects its mostly lower-risk regulated electric distribution operations and effective management of regulatory risk. Our assessment further reflects WCU's generally steady cash flow and rate-regulated utility operations with highly supportive cost recovery.

We continue to assess WCU's business risk profile as excellent.This reflects that WCU is a low-risk, regulated LDC, partially offset by its small customer base of approximately 92,000 customers in the city of Windsor. This size and lack of geographic diversity increases its susceptibility to a localized economic downturn or unfavorable local weather development. Our base case assumes that WCU will continue to benefit from Ontario's credit-supportive regulatory mechanisms such as its formula-based incentive rate-making that allows for rate updates annually between cost-of-service applications.

The stable outlook on WCU reflects our view that the low-risk, regulated distribution business will likely remain steady, with predictable cash flow and no adverse regulatory outcomes over the next 24 months. Our outlook also incorporates our expectations that financial measures will improve, reflecting FFO to debt of 17%-21% through 2026.

We could lower our ratings on WCU over the next 24 months if:

- A materially adverse regulatory ruling weakens its operating cash flow; or
- Financial measures weaken such that FFO to debt is consistently below 13%.

We could raise our rating on WCU over the next 24 months if:

- Financial measures improve such that FFO to debt is consistently above 20%; and
- The business risk profile does not weaken.

We expect FFO to debt to be about 20% through 2025 as the company recovers transmission costs from prior years and about 17% thereafter.

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.spglobal.com/ratings for further information. Complete ratings information is available to RatingsDirect subscribers at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.spglobal.com/ratings.

NEW YORK (Standard & Poor's) July 24, 2006--Standard & Poor's Ratings Services
today assigned its preliminary ratings to Volkswagen Auto Lease Trust 2006-A's
$1.5 billion asset-backed notes (see list).

The preliminary ratings are based on information as of July 24, 2006.
Subsequent information may result in the assignment of final ratings that
differ from the preliminary ratings.

The preliminary ratings reflect an initial credit enhancement of 9.75%
provided by beginning overcollateralization of 9.00% and a 0.75% nonamortizing
reserve account. In addition, through the application of excess spread,
overcollateralization is expected to build to a 10.50% target, making the
total target credit enhancement 11.25%. All percentages are measured in terms
of the initial securitization value of the leases.

A copy of Standard & Poor's complete presale report for this transaction
can be found on RatingsDirect, Standard & Poor's Web-based credit analysis
system, at www.ratingsdirect.com. The presale can also be found on Standard &
Poor's Web site at www.standardandpoors.com. Select Credit Ratings, and then
find the article under Presale Credit Reports.

PRELIMINARY RATINGS ASSIGNED

Volkswagen Auto Lease Trust 2006-A

Class	Rating	Amount (mil. $)
A-1	A-1+	266
A-2	AAA	483
A-3	AAA	544
A-4	AAA	207

European Endorsement Status

Global-scale credit rating(s) issued by S&P Global Ratings' affiliates based in the following jurisdictions [**To read more, visit Endorsement of Credit Ratings**] have been endorsed into the EU and/or the UK in accordance with the relevant CRA regulations. Note: Endorsements for U.S. Public Finance global-scale credit ratings are done per request. To review the endorsement status by credit rating, visit the spglobal.com/ratings website and search for the rated entity.

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COMMENTS — 11 Mar, 2024 | 19:32 —
APAC, United States of America, Latin America, Canada, EMEA, APAC

North American Utility Regulatory Jurisdictions Update: Ontario Remains Unchanged, Notable Developments Elsewhere

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Sector	Oil & Gas, Corporates, Oil & Gas, Infrastructure & Utilities, Utilities & Power
Tags	Americas, Latin America, APAC, EMEA
Topic	Confronting Credit Headwinds , Energy & Climate Resilience

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Key Takeaways

- Since our last report in November 2023, we have left unchanged our assessment of one utility regulatory jurisdiction, Ontario, and examined developments in numerous North American utility regulatory jurisdictions. We are also monitoring several changes across North America that, at some point, could help or hinder the business risk of various utility companies.
- After some hiccups in the past, Arizona, Ontario, North Carolina, and Nova Scotia are making progress around cost recovery in rate case proceedings.
- However, Illinois, Kentucky, and West Virginia have pushed back on utilities seeking cost recovery within their states.
- Legislation has been filed in many states that could transform heating and electricity including electrification, natural gas bans, and generation mandates around clean sources including offshore wind power.

S&P Global Ratings has been monitoring recent developments in various U.S. and Canadian utility regulatory jurisdictions in which the utilities we rate operate. Since our last report, published in November 2023, we have completed a review of Ontario and left our assessment unchanged. In other jurisdictions, we have noted the uncertainties of rate recovery on both completed and proposed capital spending, wildfire litigation, and updates on clean energy transitions and natural gas bans.

Our periodic assessments of regulatory jurisdictions provide a reference for determining a utility's regulatory advantage or risk. Regulatory advantage is incorporated into our analysis of a regulated utility's business risk profile. Our analysis covers quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation. (See **Key Credit Factors For the Regulated Utilities Industry**, published Nov. 19, 2013, for more details on each category.)

Utility Regulatory Jurisdiction Assessment

- S&P Global Ratings periodically assesses every regulatory jurisdiction in the U.S. and Canada with a rated utility or where a rated entity operates. Our last full assessment was in November 2023, in which we examined developments in numerous jurisdictions.
- These assessments, with categories from credit supportive to most credit supportive, provide a reference when determining the regulatory risk of a regulated utility or a holding company with more than one utility.
- We base our jurisdictional analyses on quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation.
- Utility regulation, no matter where on the continuum of our assessments, strengthens a utility's business risk profile, and generally underpins our ratings.

U.S. And Canadian Regulatory Utility Jurisdiction Developments

We group jurisdictions by quantitative and qualitative factors that comprise the regulatory advantage determinations we make in rating committees for approximately 220 U.S. and 30 Canadian utilities we rate.

The categories are an important starting point for assessing utility regulation and its effects on ratings. They are all credit-supportive to one degree or another because all utility regulation tends to sustain credit quality. We believe the presence of regulation, regardless of where it falls on the credit-supportive spectrum, reduces business risk and generally supports utility ratings. We therefore designate all these jurisdictions on a continuum from credit supportive to most credit supportive. These descriptions vary only in degree.

The following is a current snapshot of our assessment of each regulatory jurisdiction.

Table 1

Utility Regulatory Jurisdictions Among U.S. States And Canadian Provinces

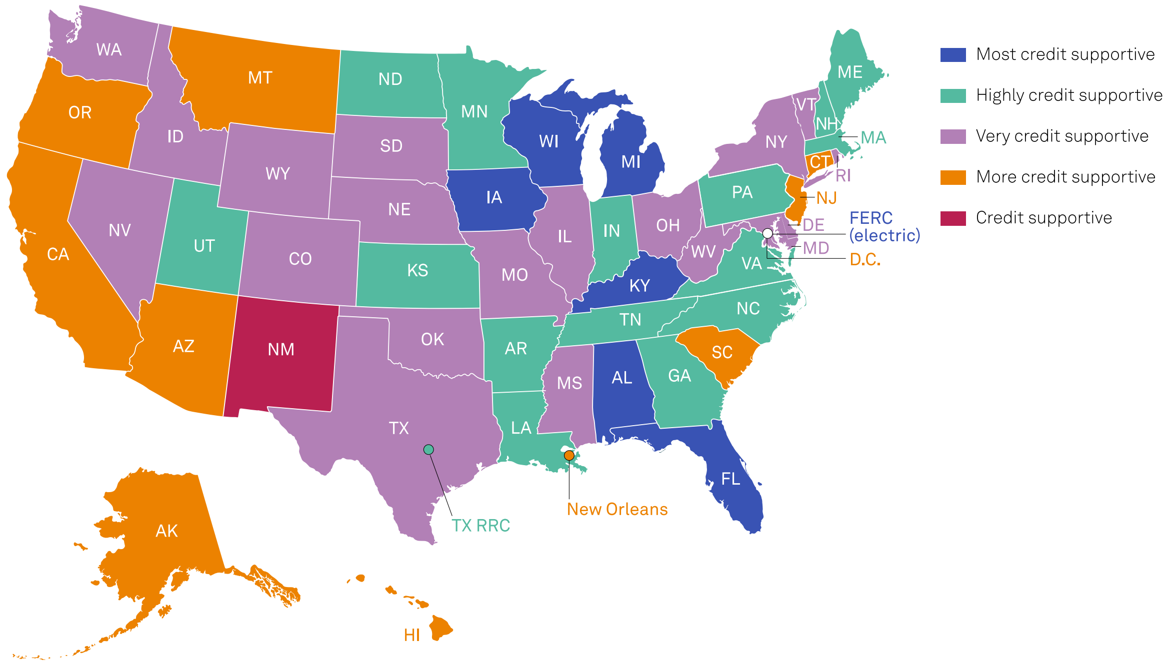
Credit supportive (adequate)	More credit supportive (strong/adequate)	Very credit supportive (strong/adequate)	Highly credit supportive (strong/adequate)	Most credit suppor (strong
New Mexico	Alaska	Colorado	Alberta	Alabama
Nova Scotia	Arizona	Delaware	Arkansas	British Columbi

Prince Edward Island	California	Idaho	Georgia	Federal Energy Regulato Commis (electric
	Connecticut	Illinois	Indiana	Florida
	District of Columbia	Maryland	Kansas	Iowa
	Hawaii	Missouri	Louisiana	Kentuck
	Montana	Mississippi	Maine	Michiga
	New Jersey	Nebraska	Massachusetts	Ontario
	New Orleans	Nevada	Minnesota	Quebec
	Oregon	New York	North Carolina	Wiscons
	South Carolina	Ohio	New Hampshire	
		Oklahoma	Newfoundland & Labrador	
		Rhode Island	North Dakota	
		South Dakota	Pennsylvania	
		Texas	Tennessee	
		Vermont	Texas RRC	
		Washington	Utah	
		West Virginia	Virginia	
		Wyoming		

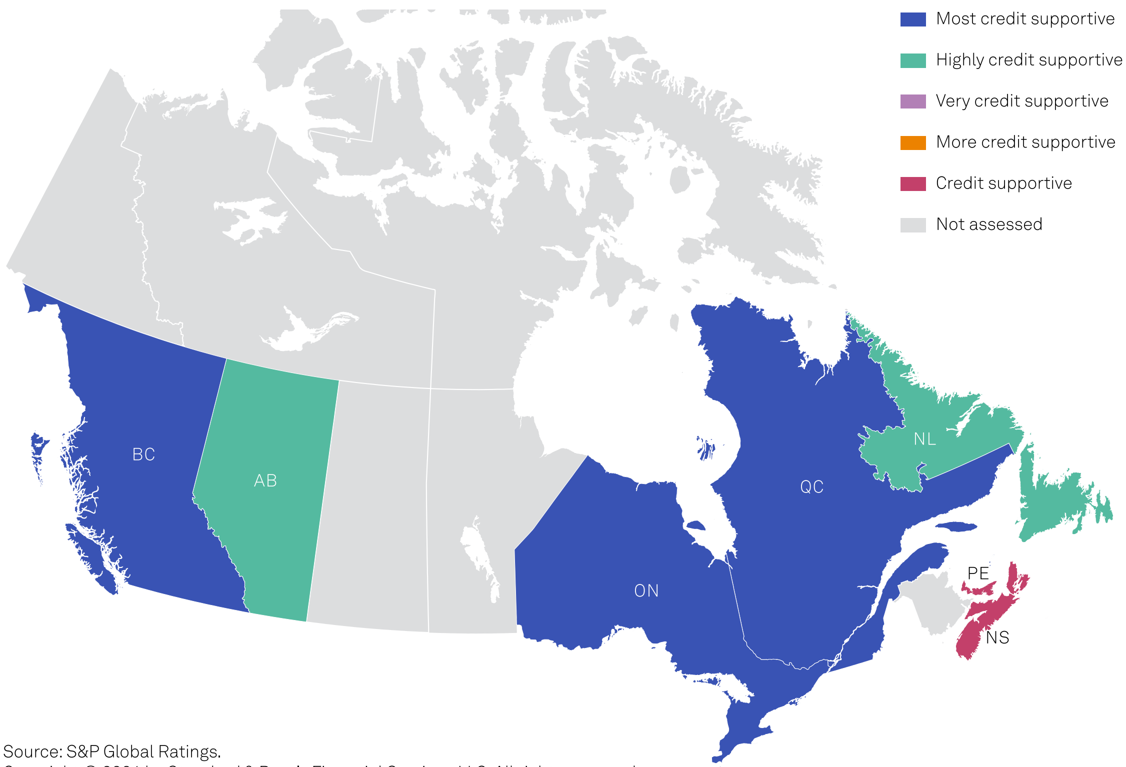
RRC--Railroad Commission of Texas. Source: S&P Global Ratings.

For jurisdictions assessed in Graphics 1 and 2, colors delineate our assessment of credit supportiveness. We do not have assessments for Canadian provinces where we do not have utility ratings. The charts depict scale and offer some detail regarding our assessment of the rules and implementation of regulation. Often, our assessments designate a stable jurisdiction slightly better or worse than its closest peers in credit quality.

Regulatory assessment by state
As of March 2024



Regulatory assessment by Canadian province/territory
As of March 2024



Reviewed, No Changes

Ontario

We concluded our review on Ontario's regulatory environment, including the Ontario Energy Board (OEB), and left our assessment unchanged at most credit supportive. OEB proactively addressed regulatory lag, particularly related to the timely recovery of rising transmission-related costs. Notably, before addressing this cost recovery lag, we had revised outlooks to negative on several Ontario electric local distribution companies (LDC). To address this lag, in July 2023, the OEB pulled forward the issuance of an inflation factor calculation that is an input to calculate uniform transmission rates (UTRs) for transmission utilities' annual rate adjustments. Typically, this had been completed in October or November. Because the inflation factor was available earlier, in September 2023, the OEB was able to approve preliminary UTRs for transmission companies.

With the updated inflation factor and revised UTRs, LDCs can file for new rates with the most current inputs, including updated transmission costs, which mitigates regulatory lag. We expect this more front-loaded rate recovery will align higher operating cash flow with LDCs' requirements to pay the higher transmission costs. In January 2024, the OEB issued its final UTRs that were largely in line with the preliminary UTRs. With this reduced lag in recovering higher transmission costs, we expect LDCs will be able to boost their financial measures.

No Revised Assessments, But Notable Developments

Arizona

In February 2024, the Arizona Corporation Commission (ACC) directed the ACC staff to draft rules to repeal both the state's energy efficiency standards and renewable generation requirements. The ACC largely cited costs to ratepayers as driving the decision. We will closely monitor the rulemaking process and its potential effect on Arizona utilities.

California

The California Public Utilities Commission (CPUC) recently approved advice letters for several regulated electric, gas, and water companies, raising the authorized return on equity (ROE) by approximately 70 basis points (bps) through the cost of capital mechanism (CCM), effective Jan. 1, 2024. In California, authorized ROEs are established separately from general rate case proceedings, based on a formula, to reflect rising bond yields. We view this as supportive of credit quality for affected regulated utilities because it helps mitigate regulatory lag, which protects utilities from the effects of rising interest rates. We believe the boost in recovery through higher rates will strengthen funds from operations (FFO) of California utilities.

Hawaii

In January 2024, House Bill 2265 was introduced in the Hawaii legislative session. This bill proposes to implement a Catastrophic Wildfire Securitization Act to allow public utilities to securitize costs from catastrophic wildfires. We expect a decision on this by June 2024. Separately, in November 2023, Hawaii's Governor announced the One Ohana Initiative, which would provide at least $150 million of public-private funds to compensate victims and their families affected by the August 2023 Lahaina wildfires. We expect this fund to be jointly funded by the State of Hawaii, Hawaiian Electric Co. Inc., Kamehameha Schools, Maui County, and other entities. While both initiatives have yet to be finalized, if approved, they would be supportive for utilities operating in Hawaii by mitigating the costs from catastrophic wildfires.

Illinois

Recent regulatory rulings by the Illinois Commerce Commission (ICC) lead us to believe the ICC may become less credit supportive toward utilities operating in the state. In November 2023, the ICC disallowed capital spending incurred by WEC Energy Group Inc.'s (WEC) subsidiary, The People's Gas Light & Coke Co. (PGL). The disallowed capital spending relates to the construction and improvement of service shops PGL owns throughout Chicago. The ICC's November 2023 rate order also rejected PGL's request to include its forecast test year safety modernization program (SMP) investment in its rate base. The ICC ordered a pause in, and an investigation of, the program, which focuses on replacing aging and at-risk pipelines (such as cast iron or ductile iron), relocating meters, and repressurizing areas of its distribution system.

The ICC recently authorized a limited rehearing of certain items, including $134 million of SMP emergency work; however, the ICC will not reconsider the disallowed spending related to its service shops. We view the disallowance as negative from a credit standpoint because parent WEC took a $179 million noncash charge to its 2023 earnings, weakening its FFO to debt in 2023. The disallowance also leads to less predictability of ratemaking under the ICC. Although PGL was able to reduce its capital spending by $700 million to $900 million over 2024-2028 to preserve its credit quality, the reduced capital spending could delay the company's progress toward replacing aging and at-risk pipelines. Cast iron and ductile iron account for roughly 25% of the company's gas distribution system.

In addition, in December 2023, the ICC within Commonwealth Edison Co.'s (ComEd) and Ameren Illinois Co.'s (AI) separate multiyear rate plans determined that their respective four-year grid plans did not adequately describe community benefits, transparency, affordability, or cost-effectiveness and did not comply with the state's Climate and Equitable Jobs Act (CEJA) of 2021. Illinois' CEJA law requires the state to transition to 50% renewable energy by 2040 and 100% clean energy by 2050 through reduced emissions and electrification. We believe the wholesale rejection of ComEd's and AI's grid plans by the ICC, which resulted in a much lower revenue increase for each company in their respective four-year rate plans, may indicate a weakening in the ICC's recent historical predictability of regulatory outcomes. Both utilities will file revised grid plans in March 2024, but there is no set deadline for the ICC to rule on the revised plans. In aggregate, the combination of disallowances and lower-than-expected rate increases may be a sign of less regulatory stability that could weaken the attractiveness of the state's regulatory framework to long-term investors.

Kansas

In January 2024, House Bill 2527 was introduced in the Kansas House of Representatives that proposes to authorize cost recovery mechanisms for certain rate base additions as well as proposed changes to the calculation of capital structures. The bill proposes that utilities be allowed to defer as a regulatory asset 100% of all depreciation expense and returns associated with all plant-in-service balances not already included in rate base.

In addition, the bill proposes that the Kansas Corporation Commission (KCC) would set rates for a public utility on a stand-alone basis when determining the revenue requirement. The KCC would be required to use a utility's test year capital structure, without regard to the capital structure or investments of any other affiliated entities, unless the utility's parent company does not hold an investment-grade credit rating from at least one nationally recognized credit rating agency.

The bill also proposes that utilities be allowed to implement a new rate adjustment mechanism to earn a return on 100% of construction work in progress for any new gas-fired generating facilities, unless the KCC determines the plant would not be a prudent addition to the utility's fleet.

We expect that the bill, if passed as presented, will provide more predictable and stable cash flows for utilities in Kansas, further strengthening credit quality. We continue to monitor the developments on the proposed legislation.

Kentucky

The Kentucky Public Service Commission (PSC) recently modified several rate case settlements to modestly lower the ROEs in the settlements, reducing the ultimate rate increases. Recently, Kentucky Power Co.'s (KPC) rate case settlement called for a base rate increase of about $75 million based on a 9.75% ROE. Separately, in KPC's recent rate case, the PSC reduced the settled rate increase by about $15 million largely to address the PSC's concerns regarding the company's transmission costs. In a separate proceeding, however, the PSC was credit supportive toward KPC by authorizing the utility to issue securitization bonds primarily for early retirement of coal generation and storm restoration costs. In aggregate, we continue to view Kentucky as most credit supportive albeit at the lower end of the category.

Maine

In November 2023, Maine voters rejected a referendum that could have resulted in the Maine government attempting to municipalize investor-owned utility transmission and distribution assets in the state. The rejection reinforces regulatory stability and reduces uncertainty, providing for the utilities in Maine to focus on strengthening infrastructure and improving reliability of operations. We view regulatory independence as one of the key attributes that underpins the credit quality of the utility industry. In general, we expect utilities to operate under a regulatory construct that is sufficiently insulated from political intervention, even during periods of economic stress, thereby protecting a utility's credit risk profile.

Massachusetts

In December 2023, the Massachusetts Department of Public Utilities (DPU) required the state's natural gas LDCs to analyze whether low- or zero-carbon non-pipeline alternatives, such as heating electrification and geothermal systems, could replace traditional gas infrastructure investments. Furthermore, the DPU ordered gas LDCs to file Climate Compliance Plans beginning in 2025 that would propose strategies to reduce greenhouse gas emissions (Scope 1 and 3). While these developments are still preliminary, we will continue to monitor them, including potential implications for the state's gas LDC's capital spending and growth prospects over the long term.

Michigan

In late 2023, Michigan passed several legislative measures that affect utilities, including Senate Bills (SB) 271, 273, 277, 502, and 519. Specifically, the actions now require 80% of power generated in the state to be derived from clean energy by 2035 and 100% by 2040; the state commits to 50% renewable energy by 2030 (60% by 2035), increases the cap on distributed generation--including rooftop solar to 10% from 1%--and a 2,500 megawatt (MW) energy storage mandate by 2030.

SB 271 includes a financial incentive for utilities that procure clean energy or storage through a purchased power agreement with third parties. Specifically, if a regulated electric utility enters into a purchase power agreement for renewable energy resources or clean energy storage with a nonaffiliated third-party, the commission shall authorize an annual financial incentive for the utility, which includes the utility's pre-tax weighted average cost of permanent capital (debt and equity) using the utility's regulated capital structure that was authorized in the most recent general rate case.

From a credit perspective, while we view the financial incentive as supportive of credit quality, the broader energy goals could also likely translate into increased capital spending by the utilities to meet the requirements of these legislative measures. As such, we will continue to monitor how affected utilities effectively navigate this development.

New Jersey

The state continues to work toward the goal of 100% of electricity sold in the state being generated from clean and renewable sources by 2035. A new proposal makes a continued effort to accelerate this by prohibiting the construction of new fossil fuel power plants. The state currently generates about 55% of its energy from fossil fuel. We do not view this as completely restrictive because it would allow for the continuation of fossil fuel peaker plants.

In addition, the commission continues to move toward its offshore wind goals of achieving 11 gigawatts (GW) of offshore wind capacity by 2040. In January 2024, the New Jersey Board of Public Utilities approved two new offshore wind proposals for a combined 3.7 GW. The 2.4 GW Leading Light Wind project is being built by Invenergy Renewables LLC and energyRE LLC, and the 1.3 GW Attentive Energy Two project is being built by TotalEnergies SE and Corio Generation Ltd. This is a positive development after the cancellation of two wind projects with Orsted A/S in 2023.

New Mexico

In January 2024, the New Mexico Public Regulation Commission (NMPRC) authorized Public Service Co. of New Mexico (PSNM) a rate increase of about $15 million based on an authorized 9.26% ROE. It also ordered a $38 million rate refund over two years of previously collected payments on an expired power plant lease. In January 2023, NMPRC transitioned to the gubernatorial appointment of commissioners. While we expected that this change could improve New Mexico's support of credit quality, PSNM's first rate order under this new construct has initially fallen short of our expectations. At the same time, we believe there were unique factors in this rate case that make it difficult to determine a long-term view of New Mexico's regulatory environment. These include the participation of only two out of three commissioners and the resolution of legacy issues concerning PSNM's generation. We expect PSNM will be filing more frequent rate cases in the future, which will inform our view of the new NMPRC.

New York

Governor Kathy Hochul introduced The Affordable Gas Transition Act (AGT) bill that, among other things, would empower the New York Public Service Commission (NYPSC) to direct utilities to manage the transition to clean energy sources responsibly and affordably. If passed, AGT would give NYPSC discretion on controlling gas utilities expansions in their existing service territory and would restrict distributors from expanding their service territories beginning in 2026. AGT would further limit growth of gas utilities in the state. This requires substantial and accelerated investments in New York's electric infrastructure consistent with the Climate Leadership and Community Protection Act.

North Carolina

We view recent regulatory outcomes in North Carolina as constructive for credit quality. In December 2023, the North Carolina Utilities Commission (NCUC) authorized a three-year cumulative rate increase for Duke Energy Carolinas LLC (DEC) totaling $769 million. The decision includes revenue increases of about of $469 million in 2024, $174 million in 2025, and $159 million in 2026. In August 2023, affiliate Duke Energy Progress LLC (DEP) also received a multiyear rate increase of $494 million through 2026. We consider both rate case decisions as supportive of credit quality because they bolster both companies' financial measures and further highlight sound management of regulatory risk.

We believe the rate increases will provide stability in cash flows through 2026, which is important given the companies' elevated capital spending. DEC and DEP received ROEs of 10.1% and 9.8% in 2023, respectively, both above industry averages. Potentially offsetting the higher ROE for DEC, the North Carolina Attorney General recently filed an appeal on the DEC rate case because they were authorized a higher ROE than DEP. We will continue to monitor the appeal and future developments and any effect on DEC's rates.

Nova Scotia

We view Nova Scotia's regulatory construct as credit supportive due to the history of political interference that weakens the regulatory jurisdiction's predictability and increases uncertainty for its utilities and stakeholders. However, recently the government of Nova Scotia proposed to compensate Nova Scotia Power Inc. (NSPI) C$117 million to offset a deferred fuel cost liability. Because any further recovery of fuel costs would have significantly pressured customer bills in Nova Scotia, the provincial government proposed to pay NSPI C$117 million up front and recover the amount from customers over the next 10 years. This compensation to NSPI from the provincial government indicates the government's willingness to extend support under challenging circumstances, thereby improving the operating environment for NSPI. We consider this supportive of credit quality in the province.

In addition, the provincial government announced its 2030 Clean Power Plan, which is largely consistent with NSPI's investment strategy. Furthermore, the provincial government also approved legislation to include battery storage projects in base rates.

West Virginia

Earlier this year, the Public Service Commission of West Virginia (WVPSC) disallowed about $232 million of under-recovered energy costs sought during Appalachian Power Co.'s and Wheeling Power Co.'s Expanded Net Energy Cost (ENEC) filing. Furthermore, the WVPSC ordered the companies to recover the remaining under-recovered balance of $321 million over a 10-year period. Previously the companies had reached a settlement with the West Virginia Energy Users Group and West Virginia Coal Association, but not the WVPSC staff, to recover all the under-recovered costs. In arriving at this decision, the WVPSC stated that the companies were imprudent in fuel planning, fuel practices, and market strategies, which caused a lack of adequate coal supplies at a time when energy was more expensive.

While we view this development as negative for Appalachian Power and Wheeling Power, we do not believe this indicates a deterioration in the broader regulatory environment in the state at this time. Other electric utilities in the state, namely Monongahela Power Co. and Potomac Edison Co., recently reached settlements with WVPSC staff, among various other intervenors, concerning the companies' rate case and ENEC filings.

Furthermore, we view both settlements in these cases as constructive. In particular, Monongahela Power's and Potomac Edison's ENEC settlements call for the recovery of the companies' ENEC under-recovered balance of about $255 million over the next three years. We will continue to monitor further developments in these proceedings to determine if they impact our view of West Virginia investor-owned utilities' credit quality.

Related Research

- **WEC Energy Group Inc.'s Financial Measures Hold Up Despite Disallowances In Illinois Rate Cases**, Jan. 23, 2024
- **Commonwealth Edison's Rate Case Outcome Pressures Credit Measures**, Dec. 21, 2023
- **Key Credit Factors For The Regulated Utilities Industry**, Nov. 19, 2013

This report does not constitute a rating action.

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Vulnerable Energy Consumers Coalition Interrogatory #N-M1-3-VECC-18

Interrogatory

Reference:

Exhibit M1, pages 63-70 and 74

Preamble:

At page 63, LEI identifies five major OEB regulatory/policy changes enacted since 2006 that affect electricity distributors and/or transmitters. These policies are then discussed individually on pages 64 to 70. At page 64, LEI states:

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

At page 74, LEI states:

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

Question(s):

a) For each of the identified policies please provide LEI's assessment as to whether it: i) reduces uncertainty, ii) increases flexibility and/or provides compensation for changes in risk.

b) For each of the identified new polices please comment on whether LEI considers the policy as: i) reducing uncertainties that existed in 2006 (as opposed to addressing just new uncertainties) and/or ii) providing compensation for risks that existed in 2006 (as opposed to just addressing new risks).

c) It is noted that the list of policies enacted since 2006 that affect distributors does not include either: i) the Incremental Capital Module (ICM) introduced in the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors issued in July 2008 or ii) the Advanced Capital Module (ACM) introduced in the Report of the Board - New Policy Options for the Funding of Capital Investments in September 2014. Does LEI consider these new regulatory mechanisms as impacting the business risk faced by electricity distribution utilities? if not, why not? If yes, why were these policies not included in LEI's assessment? If yes, do these policy changes serve to reduce uncertainty, increase flexibility, and/or provide compensation for changes in risks? If yes, does LEI consider these new policies as i) reducing uncertainties that existed in 2006 (as opposed to addressing just new uncertainties) and/or ii) providing compensation for risks that existed in 2006 (as opposed to just addressing new risks).

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

a) Please see indicative table below:

Policy	Reduce uncertainty	Increase flexibility
Electricity distributors' DVA review initiative	✓	✓
Renewed regulatory framework for electricity		✓
Rate design for electricity distributors	✓	
Rate design for commercial and industrial customers	✓	
Framework for energy innovation: distributed resources and utility incentives	✓	

b) The renewed regulatory framework for electricity and rate design changes reduces uncertainties that existed in 2006 as these policies replaced IRM and rate design that existed in 2006. "Framework for energy innovation: distributed resources and utility incentives" arguably relates to addressing new risks.

c) LEI considered selected major policy initiatives implemented since 2006. Further, ICM was also reiterated in the "Renewed Regulatory Framework for Electricity Distributors" report. LEI's view is that the ACM can be viewed as an extension of the OEB's RRFE report.

School Energy Coalition Interrogatory #N-M1-12-SEC-22

Interrogatory

Reference:

Exhibit M1, pages 74 and 143

Question:

LEI states: i) “With respect to the major OEB regulatory mechanisms introduced since 2006, LEI believes that they have generally reduced the risks for electricity distributors” (p.74), and ii) “The risk profile of electricity transmitters is similar to, if not lower than, that of electricity distributors.” (p.143). Based on those conclusions, please provide LEI’s specific recommendation for equity thickness for each of the electricity distributors and electricity transmitters.

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

Please see LEI response in IR #N-M1-2-VECC-17 a).

Vulnerable Energy Consumers Coalition Interrogatory #N-M1-2-VECC-17

Interrogatory

Reference:

Exhibit M1, page 62

Preamble:

At page 62, LEI states:

"The current policy of considering the impact of risk factors when there is a significant change in business/financial risks is a reasonable approach, which LEI recommends be retained."

Question(s):

a) In preparation of its Report, did LEI undertake an assessment or form any opinions as to whether there has been a significant change in the business/financial risk faced by electricity distributors since 2006 (or whatever date LEI considers the OEB to have undertaken its last formal assessment of such risk)? If yes, please provide. If not, why not?

b) In preparation of its Report, did LEI undertake an assessment or form any opinions as to whether there has been a significant change in the business/financial risk faced by OPG since 2017 (or whatever date LEI considers the OEB to have undertaken its last formal assessment of such risk)? If yes, please provide. If not, why not?

c) In preparation of its Report, did LEI undertake an assessment or form any opinions as to whether there has been a significant change in the business/financial risk faced by Enbridge since 2023 or EPCOR Natural Gas since 2006 (or whatever date LEI considers the OEB to have undertaken its last formal assessments of such risks associated with each utility)? If yes, please provide. If not, why not?

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

a) While Section 4.3 of the LEI report indicates that regulatory risk for electricity distributors has slightly decreased since 2006, a full assessment of business/financial risks (along with forward-looking cash flow modelling) required to assess the appropriateness of the existing equity thickness for electricity distributors, OPG, EPCOR Natural Gas (and other OEB-regulated utilities) is outside the scope of this report.[5]

b) Please see LEI response in a) above.

c) Please see LEI response in a) above.

[5] Utility-specific business and financial risk analysis pertaining to appropriate equity thickness is outside LEI's scope of work for this proceeding.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M1, p.63]

Question(s):

LEI has outlined a number of OEB regulatory/policy changes since 2006. Appendix A to these interrogatories outlines a number of additional OEB regulatory/policy changes since 2011. For each, please provide Concentric's view on how each would impact utility business and financial risk.

Response:

In the table below, Concentric summarizes the regulatory/policy changes outlined in the LEI report, as well as the additional regulatory/policy changes in SEC's Appendix A. Concentric's overall assessment is that these regulatory and policy changes have somewhat reduced certain utility cost recovery risks on an absolute basis, but notes that regulatory/policy changes can be in reaction to factors that can increase utility risk (e.g., distributed resources). Further, the existence of a regulatory/policy change does not necessarily mean the utilities benefit from them (e.g., when ICM requests are denied).

Further, these changes, either individually or as a package, have not appeared to materially change investors' perceptions of regulatory risk in Ontario. For example, UBS, which evaluates "mechanisms that reduce regulatory lag" in its ranking of North American jurisdictions, ranks Ontario in its third tier out of five. In addition, as described in Concentric's report, it is necessary to compare overall regulatory risk in Ontario to regulatory risk in peer jurisdictions when assessing the cost of capital. In Concentric's analysis (see pages 125-127 of Concentric's report), we found the aggregate business risk profiles of the North American proxy groups reflect similar risk as the Ontario electric and gas utilities, other than OPG. These Ontario utilities are closely aligned with the North American proxy groups in terms of commodity price risk and the use of infrastructure recovery mechanisms such as riders and capital trackers. We also find a comparable level of regulatory protection for mitigating regulatory lag through the use of deferral accounts.

Regulatory/Policy Change	Description	Risk Impact
Electricity distributors' DVA review initiative (EB-2008-0046; OEB report issued in July 2009)	Provides a systematic approach to the review and disposition of DVAs.	Modest reduction (clarifies timing and classification of DVAs).
Renewed regulatory framework for electricity (EB-2010-0377, EB-2010-0378 and EB-2010-0379; OEB report issued in October 2012)	Updates the regulatory framework for electricity distributors.	Neutral impact (clarifies the framework, but incentive regulation increases cost recovery risks).
Rate design for electricity distributors (EB-2012-0410; OEB report issued in April 2015)	Adopts a new policy under which electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge.	Reduction in volumetric risk related to residential sales for electricity distributors.
Rate design for commercial and industrial customers (EB-2015-0043; OEB Staff report issued in February 2019)	OEB Staff Report to the OEB that provides OEB staff's recommendations and proposals for proposed commercial and industrial rate design changes.	N.A. (no OEB decision was issued).
Framework for energy innovation: distributed resources and utility incentives (EB-2021- 0118; OEB report issued in January 2023).	Framework that establishes OEB expectations, a benefit cost analysis framework, and the ability for electric distribution utilities to seek a new deferral account and incentives related to distributed energy resource integration.	Neutral to higher risk (this initiative reflects an <u>expectation</u> that utilities begin to seek 3rd party solutions for traditional poles and wires, which means having to seek counterparties, taking on operational/contractual risks, and new solutions could result in capacity or reliability issues; offsetting this is a modest cost recovery risk reduction via the ability to seek deferral accounting for certain costs).
Introduction of Advanced Capital Module (ACM). See Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (September 18, 2014)	Revises the capital module policy by adopting the Advanced Capital Module ("ACM") framework.	Modest risk reduction due to the acceleration of the timing of review.

Regulatory/Policy Change	Description	Risk Impact
MAAD transaction deferred rebasing lengthened from 5 to up to 10 years, at discretion of utility. See Report of the Board Rate-Making Associated with Distributor Consolidation (March 26, 2015)	Sets OEB policies on the duration of the deferral period for rebasing following the closing of a MAADs transaction and establishes mechanism for adjusting rates to reflect incremental capital investments during the deferred rebasing period.	Risk neutral (reduces certain capital-related risks; longer deferred rebasing introduces new risks related to performance and maintenance of financial integrity during the rebasing period).
OEB requiring residential customers to be billed on a monthly basis (previously many were bimonthly). See Distribution System Code (DSC) Amendments (April 15, 2015). Related, reduced billing lag as demonstrated by OEB's reduction in default working capital from 13% to 7.5%. See OEB Letter, Allowance for Working Capital for Electricity Distribution Rate Applications, June 3, 2015)	<u>Monthly Billing</u> The OEB amended the DSC related to billing frequency. <u>Reduced Billing Lag</u> The OEB determined that the default value for working capital allowance for electricity distributors will be 7.5% of the sum of the cost of power and OM&A.	<u>Monthly Billing</u> Modest risk reduction (incremental costs associated with monthly billing incurred by distributors can be mitigated by more frequent and lower bills, which can improve collection costs and bad debts). <u>Reduced Billing Lag</u> Modest risk increase due to reduced cash flows.
Reduction of ACM/ICM deadband from 20% to 10%. See Supplemental Report: New Policy Options for the Funding of Capital Investments (Jan 22, 2016).	The OEB reduced the dead band from 20% to 10%, citing that adjusting the level of the dead band is a practical decision to balance proposals for necessary incremental capital funding versus marginal applications.	Reduction in risk related to capital recovery as the reduction to the dead band in the materiality threshold calculation for the ACM and ICM makes those mechanisms more accessible to distributors.
Expansion of eligibility for ICM for utilities on deferred rebasing period. See OEB Letter Re: Incremental Capital Modules During Extended Deferred Rebasing Periods (Feb 10, 2022).	The OEB provided flexibility for electricity distributors considering consolidation by allowing them to apply for incremental capital funding for an annual capital program during the extended rebasing period if they meet certain criteria.	Risk neutral (reduces certain capital-related risks; longer deferred rebasing introduces new risks related to performance and maintenance of financial integrity during the rebasing period).
Annual update to LV Rates through IRM/rate adjustment process, whereas previously only updated at rebasing. See Updated Filing	The OEB allowed embedded or partially embedded distributors to update the Low Voltage Service Rates on an annual basis as part of each	Modest reduction in risk (the update may reduce the variance between the low voltage costs charged by a host distributor to an

Regulatory/Policy Change	Description	Risk Impact
Requirements for Electricity Distribution Rate Applications, Chapter 3 (June 15, 2023).	distributor's incentive-rate setting application.	embedded distributor and low voltage revenues collected through low voltage service rates that the embedded distributor charges its customers).
UTRs issued earlier in year allowing for more up to date RTSRs included in annual rate adjustments applications. See OEB Letter, 2024 Preliminary Uniform Transmission Rates and Hydro One Sub Transmission Rates (September 28, 2023).	Previously, Uniform Transmission Rates ("UTRs") were issued on a final basis in December or January. Typically, distributors with rate years beginning January 1 would not be able to use new UTRs in the Retail Transmission Service Rate ("RTSR") calculations until the following year. Now the OEB issues preliminary UTRs which allows for the UTR data to be integrated into the rate applications.	Modest reduction in risk (the OEB decision is expected to decrease amounts accumulated in retail transmission variance accounts).
Introduction of OEB NWS Guidelines which provides opportunities for utilities during IRM (or even in circumstances existing Custom IR plan) to seek additional funding opportunities for non-wires solutions. See Non-Wires Solutions Guidelines for Electricity Distributors (March 28, 2025)	The OEB granted the option to file a request for funding for non-wires solutions outside of rebasing to distributors using any rate-setting methodology.	Risk neutral (the application process allows the OEB to assess the proposed non-wires solutions and funding requests as they relate to the system needs outlined in distribution system plans; the OEB can better understand forecasted impacts of non-wires solutions on the distributor's revenue requirement and load forecast).