Decision **27084-D02-2023**

NP 2025-2026 General Rate Application
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Alberta Utilities Commission

Determination of the Cost-of-Capital Parameters in 2024 and Beyond

October 9, 2023

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1 Decision summary

1. In this generic cost of capital (GCOC) decision, the Alberta Utilities Commission adopts a formulaic approach, utilizing the equity risk premium (ERP) methodology, to calculate the fair rate of return on equity (ROE) for Alberta's electric and gas utilities in 2024 and beyond. The Commission has determined that the ROE resulting from the formulaic approach will uniformly apply to all of the utilities.

2. This decision also outlines the approved deemed equity ratios (sometimes referred to by parties as "equity thickness"; collectively, the ROE and equity ratios, are referred to as "cost-of-capital parameters") for the utilities on a final basis. Specifically, accounting for differences in the risk of each of the utilities, the Commission has determined that no change is required to the deemed equity ratios approved in the 2018 GCOC decision.[1]

3. The Commission institutes a mandatory review of cost-of-capital parameters every five years, subject to mid-term reopeners either at its own discretion or upon application from interested parties. The established cost-of-capital parameters will apply to the following utilities:

- AltaLink Management Ltd.
- Apex Utilities Inc.
- ATCO Electric Ltd.
- ATCO Gas and Pipelines Ltd.
- ENMAX Power Corporation
- EPCOR Distribution & Transmission Inc.
- FortisAlberta Inc.
- KainaiLink L.P.
- City of Lethbridge
- PiikaniLink L.P.
- The City of Red Deer
- TransAlta Corporation

4. The Commission's decision to implement the formulaic approach for ROE determination is driven by a commitment to reduce regulatory lag and regulatory burden, enhance transparency, and deliver regulatory certainty, while balancing the interests of all stakeholders. This approach is a significant step for GCOC proceedings towards a more efficient, predictable and cost-effective regulatory process that ultimately benefits ratepayers, utilities and the broader public interest in Alberta.

[1] Decision 22570-D01-2018: 2018 Generic Cost of Capital, Proceeding 22570, August 2, 2018.

5. The Commission approves the following formulaic approach to determine the ROE in 2024 and subsequent years:

$$ROE_t = 9.0\% + 0.5 \times (\mathrm{YLD}_t - 3.10\%) + 0.5 \times (\mathrm{SPRD}_t - \mathrm{SPRD}_{base})$$[2]

6. That is, in each year, the approved ROE will be determined by adjusting the notional ROE of 9.0 per cent approved in this decision by the difference in forecast long-term Government of Canada (GoC) bond yield (YLD_t) and utility bond yield spread ($SPRD_t$) from their base values of 3.10 per cent and the bond yield spread for the month of February 2023, respectively. These forecasts will be calculated by the Commission in early November of each year as follows:

(i) The forecast long-term GoC bond yield will be calculated as the weighted average of (a) the 30-year GoC bond yield forecasts published by Royal Bank of Canada (RBC), TD Bank (TD) and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (b) the naïve forecast[3] representing the average long-term GoC bond yield[4] over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.

(ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield[5] and the long-term GoC bond yield[6] over the period October 1 to October 31 of each year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

7. The cost-of-capital parameters for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding. However, the determinations in this proceeding may be considered in other proceedings should issues respecting ROE and deemed equity ratios arise for these utilities.

2 Background and procedural summary

8. On January 3, 2022, the Commission established a bifurcated process for this proceeding with the goal of determining ROE and deemed equity ratios. The first part of the proceeding (Stage 1) established the cost-of-capital parameters for 2023 and was completed on March 31, 2022, with the release of Decision 27084-D01-2022.[7] This decision addresses the second part of the proceeding (Stage 2), establishes a formulaic approach for setting ROE in 2024 and each year

2 The Commission has determined that it will use the bond yield spread for the month of February 2023, using the method set out in Section 6.5.3 of this decision.
3 A "naïve forecast" is a forecasting method that uses actual values from a previous period.
4 Bank of Canada CANSIM Series V39056.
5 Bloomberg Series C29530Y.
6 Bank of Canada CANSIM Series V39056.
7 Decision 27084-D01-2022: 2023 Generic Cost of Capital, Proceeding 27084, March 31, 2022.

thereafter, and sets the deemed equity ratios for the utilities. More specifically, the scope of Stage 2 comprised the following key objectives:

- Explore potential formula-based approaches for determining the ROE and identify a preferred formulaic method. This approach was intended to enhance transparency and predictability, ultimately saving both customers and Alberta utilities significant time, resources and costs associated with conducting fully litigated proceedings every one to three years.
- Establish the initial numerical variables required for the formula. This included defining an initial base, or notional ROE, that would form an integral part of the formula and serve as the basis for determining the ROE for the 2024 and future test years.
- Delineate the process for calculating the ROE in future test years while ensuring clarity and consistency in the methodology.
- Identify future processes or thresholds that would trigger a review of the formulaic approach and any necessary adjustments by the Commission, should such adjustments be deemed necessary.
- Evaluate whether the Commission should revise deemed equity ratios while employing a formulaic approach to determining the ROE.

9. By pursuing these objectives, the Commission aimed to provide a more structured and efficient framework for determining ROE and related parameters for 2024 and beyond.

10. Each of the utilities, except Lethbridge, Red Deer, TransAlta, KainaiLink L.P. and PiikaniLink L.P., actively participated in this proceeding. ATCO Electric and ATCO Gas (ATCO Utilities), Apex and Fortis co-sponsored the evidence of Dr. Bente Villadsen and Frank Graves. Apex also sponsored the stand-alone evidence of Michael Tolleth. AltaLink and EPCOR co-sponsored the evidence of Dylan D’Ascendis. ENMAX sponsored the evidence of Concentric Energy Advisors, Inc. (James Coyne and John Trogonoski) and Nicole Martin. Additionally, each of Apex, Fortis and the ATCO Utilities filed company-specific evidence.

11. The Consumers’ Coalition of Alberta (CCA), the Office of the Utilities Consumer Advocate (UCA), and the Industrial Power Consumers Association of Alberta (IPCAA) (collectively, the interveners or customer groups) also actively participated in the proceeding. The CCA sponsored the evidence of Jan Thygesen; the UCA sponsored the evidence of Dr. Sean Cleary and Russ Bell; and IPCAA sponsored the evidence of Dustin Madsen.

12. To assist with the development of a comprehensive record and to prevent prolonged and unproductive debates among the parties regarding the suitability of various utility comparator groups used to construct models for estimating the fair ROE for Alberta utilities, the Commission took a proactive approach. At the outset of Stage 2 of the proceeding, on October 14, 2022, the Commission organized a technical conference for parties (involving participants from utilities and customer groups) with the primary purpose to discuss and formulate a comparator group of representative utilities that would inform the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE.

13. The outcome of the discussions during the technical conference was documented in appendixes A and B of the Commission's letter, dated October 24, 2022,[8] which captured the consensus among parties regarding the Commission's proposed screening criteria for determining a comparator group. The appendixes also highlighted other areas where consensus was achieved or, in some instances, where consensus was not achieved. While agreement was reached on the majority of topics discussed at the technical conference, some matters still required further input from all parties. These additional submissions were subsequently received by the Commission on November 2, 2022.

14. On November 10, 2022, the Commission issued its determinations on the unresolved matters and, using the approved screening criteria, produced the list of comparator utilities. The Commission also circulated to parties a preliminary list of issues to be considered in this proceeding and provided parties the opportunity to highlight any material issues they believed the Commission should consider in Stage 2 of this proceeding that had not been identified in the list. Based on parties' feedback, a finalized issues list for Stage 2 of this proceeding was released on November 29, 2022, which parties used as a foundation for their evidentiary submissions.

15. In addition to having parties file evidence, the Commission's processes included information requests (IRs) and responses to evidence filed and/or sponsored by the utilities; IRs and responses to evidence sponsored by the interveners; concurrent rebuttal evidence filed by the utilities and interveners; and a one-week virtual oral hearing. The Commission also established a process for simultaneous written argument and reply argument. The Commission considers that the record of this proceeding closed with the filing of reply arguments on July 11, 2023.

16. The Commission reviewed the entire record in coming to this decision; lack of reference to a matter addressed in the evidence and submissions does not mean that the Commission did not consider it.

3 Fair return standard

17. The legislation that governs the Commission requires that it fix just and reasonable rates for the utilities it regulates.[9] The Commission is guided in this task by well-developed case law on the meaning of just and reasonable rates, which includes determining a fair return on the equity component of invested capital, or the fair return standard. These concepts are set out in three seminal decisions: the Supreme Court of Canada's decision in *Northwestern Utilities v Edmonton (City),*[10] and two cases from the Supreme Court of the United States, *Bluefield*

[8] Exhibit 27084-X0239.01.

[9] See Section 89 of the *Public Utilities Act;* Section 36(a) of the *Gas Utilities Act;* and Section 121(2)(a) of the *Electric Utilities Act.* Note that the *Electric Utilities Act* also requires the Commission to provide an owner of an electric utility with a reasonable opportunity to recover a fair return on the equity of shareholders of the electric utility as it relates to the investment (Section 122(1)(a)(iv)). The *Gas Utilities Act* and the *Public Utilities Act* requires the Commission to fix a fair return on the rate base (Section 37(1)). The Commission considers these statutory requirements to be the same.

[10] *Northwestern Utilities v Edmonton (City)* [1929] SCR 186 (*Northwestern Utilities*).

Waterworks and Improvement Company v Public Service Commission of the State of West Virginia,[11] and *Federal Power Commission v Hope Natural Gas Company.*[12]

18. In *Northwestern Utilities*, the Supreme Court of Canada addressed whether a board had correctly set the rate for a utility. In enunciating the meaning of "fair return," the court wrote:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[13]

19. A similar statement was made by the Supreme Court of the United States in *Bluefield*:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties …[14]

20. In *Hope*, the Supreme Court of the United States also spoke to comparable investments, as well as the importance of financial integrity and capital attraction:

> The ratemaking process under the Act, *i.e.,* the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the *Natural Gas Pipeline Co.* case that "regulation does not insure that the business shall produce net revenues."… But, such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[15] [footnotes omitted]

21. The requirements of comparable investments, financial integrity, and capital attraction remain fundamental to setting a fair return. The Commission and its predecessors have employed

[11] *Bluefield Waterworks and Improvement Company v Public Service Commission of the State of West Virginia,* 262 US 679 (1923) (*Bluefield*).
[12] *Federal Power Commission v Hope Natural Gas Company,* 320 US 591 (1944) (*Hope*).
[13] *Northwestern Utilities,* page 193.
[14] *Bluefield,* page 692.
[15] *Hope,* page 603.

these principles in setting rates of return,[16] and other regulators also apply these principles.[17] All three components must be satisfied to arrive at a fair return.

22. While satisfying these principles is fundamental to arriving at a fair return, the foundational cases also highlight the importance of ensuring that the interests of utilities are considered with those of consumers, in order to ensure that rates are just and reasonable. In *Northwestern Utilities,* the court wrote that the board had a duty to "to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested."[18] Similarly, in *Hope,* the court stated that "… the fixing of 'just and reasonable rates' involves a balancing of the investor and consumer interests."[19]

23. The National Energy Board outlined the balancing exercise as follows:

> To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline [natural gas transmission system] to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring that the Mainline's costs are not overstated.[20]

24. The Commission must therefore set a rate of return, and ensure that the fair return requirements of comparable investments, financial integrity, and capital attraction are satisfied, while also being mindful of the need to ensure that rates are just and reasonable for both the utilities and consumers. As noted by the Commission in the 2018 GCOC decision:

> The Commission exercises its judgment in determining a total return for each utility to establish rates that provide the utility a reasonable opportunity to earn a fair return on invested capital while ensuring that rates are just and reasonable so that customers are not paying more than is required to maintain safe, reliable and economic service.[21]

25. The Commission must therefore review all evidence before it, in order to ensure that it achieves the three fundamental requirements in setting a fair return, while at the same time ensuring that the decision it arrives at results in rates that are just and reasonable for both utilities and consumers.

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16 Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd., Application 1271597, July 2, 2004, page 13. See also Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571, November 12, 2009, which provided an extensive discussion of the fair return standard at paragraphs 82-109.

17 See National Energy Board Decision RH-2-2004, Reasons for Decision, TransCanada Pipelines Limited, Phase II, Released: April 2005.

18 *Northwestern Utilities,* pages 192-193.

19 *Hope,* page 603.

20 *TransCanada Pipelines Limited v Canada (National Energy Board)*, 2004 FCA 149 (*TransCanada Pipelines*), paragraph 34.

21 Decision 22570-D01-2018, paragraph 37.

26. The Commission has significant discretion in addressing this complex task. In *Bluefield,* the court wrote that "(w)hat annual rate will constitute just compensation depends on many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts."[22] In a concurring judgment in the *Northwestern Utilities* case, Justice Smith noted that "[t]he question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board."

27. There were 949 exhibits filed in this proceeding, and thousands of pages of evidence and submissions. There were significant matters of dispute between the parties and expert opinion that differed on critical points. The Commission must consider and weigh this evidence, and applying its judgment, make decisions that meet the fair return standard, and result in just and reasonable rates. As noted by Justice Rothstein of the Federal Court of Appeal:

> … In cost of capital proceedings, the Board is entitled, on the basis of the evidence before it and the use of its own judgment, to choose a methodology for determining cost of capital and to estimate the cost of capital for a forthcoming year. Very often, the Board's estimate will not reflect the precise estimates of one side or the other or of one witness or another. Having regard to all the evidence, the Board will determine its own estimate.[23]

4 Relevant changes in macroeconomic and capital market conditions since the 2018 GCOC decision

28. In this section, the Commission considers changes in economic and market conditions, both global and domestic, since the 2018 GCOC decision. Macroeconomic conditions, such as economic growth and interest rates, factor into the Commission's determination of an approved fair cost of capital because they are inputs in the models used to develop those costs.

29. In this proceeding, there was a general consensus among witnesses that the COVID-19 pandemic, and the varied responses to it in different countries, produced uncertain and volatile macroeconomic and capital market conditions not just in Canada or North America, but worldwide. This instability was compounded by government and central bank policies that, first, attempted to stabilize economic activity and then reacted to a quick economic rebound as the pandemic subsided. The U.S. and Canadian central banks lowered policy interest rates at the onset of the pandemic to promote economic activity while also purchasing bonds to stabilize debt markets (this asset-purchasing transaction is commonly referred to as quantitative easing). When the pandemic subsided in 2022, central banks increased interest rates in response to higher inflation and reduced their bond holdings (quantitative tightening). The Commission observes that economies and capital markets are still managing the residual fallout of the pandemic.

30. In the 2018 GCOC decision, the Commission concluded that global and Canadian economic conditions had improved since the 2016 GCOC proceeding.[24] The Commission made note of global and national economic growth, reduced market volatility, a modest increase in the 30-year GoC bond yield, and a compression in credit spreads. However, having regard to

[22] *Bluefield,* page 692.
[23] *TransCanada Pipelines*, paragraph 58.
[24] Decision 22570-D01-2018, paragraph 192.

downward pressure from other factors, the Commission found that the approved ROE for 2018 should be set at or near that of the 2016 proceeding.[25]

31. The evidence in this proceeding is that macroeconomic and capital market conditions are somewhat less favourable now than they were at the time the 2018 GCOC decision was issued. However, the Commission views the current conditions as transitionary and likely to improve as inflation abates and the economy adjusts to higher interest rates than the abnormally low rates that prevailed in the relatively recent past.

32. The Commission agrees that higher inflation and higher interest rates since 2018 have created uncertainty in the broader economy, which is reflected in market volatility and in the Bank of Canada's (BoC) expectation for lower growth in 2023 and 2024. The credit spread between A-rated utilities and government bonds has also increased somewhat, demonstrating investors' concerns about the macroeconomic conditions for utilities. Capital market volatility, although having moderated recently, could flare up again until investors are once again confident that conditions have stabilized.

33. The Commission acknowledges the risk of a recession, but defers to the BoC's guidance as submitted by Dr. Cleary and Dr. Villadsen that economic growth will continue albeit at a slower pace. The Commission also notes that Alberta is resource dependent and agrees with Dr. Cleary's assessment that the anticipated economic slowdown in the rest of Canada will be less pronounced in Alberta as a result.

34. The Commission expects a normalization in macroeconomic conditions, including a sustained, if uneven, amelioration in the pace of inflation. As well, the Commission expects an eventual halt, then partial reversal, in the BoC's policy interest rate hikes at, or not much beyond, the level at which rates presently stand. Lower gross domestic product (GDP) growth is expected to reduce demand in the economy and, consequently, inflationary pressures as well. The Commission expects that the BoC will achieve its inflationary target; however, timelines for meeting that target remain unclear. As macroeconomic conditions stabilize, capital market conditions are expected to respond in kind with lower volatility and stabilizing bond yields. The Commission expects a higher interest rate environment for longer, which would be reflected in higher utility bond yields relative to 2018. However, the Commission agrees with J. Thygesen's contention that a slower growth environment or a recession may require the BoC or the Federal Reserve in the U.S. to reduce interest rates, which would put downward pressure on future utility bond yields, all else being equal.

35. Even accepting that there has been a deterioration in macroeconomic conditions since 2018, the Commission finds that many economic indicators (among them prolonged disruptions in global supply chains; pronounced volatility in prices for energy, grain and other foodstuffs; widespread workforce dislocations; health concerns; and pressures on medical systems, etc.) have begun stabilizing to a greater or lesser extent since the height of the pandemic and Russia's invasion of Ukraine. In addition, of the remaining post-pandemic economic shocks, including higher interest rates and inflation in excess of the BoC's target range, the Commission finds that

[25] Decision 22570-D01-2018, paragraph 206.

Alberta's regulatory framework has, to a significant extent, shielded Alberta utilities from much of the impact of these systematic risks.[26]

36. The fact that a supportive regulatory environment can provide significant protection to utilities from rising costs occasioned by adverse macroeconomic changes is demonstrated by robust returns achieved by Alberta utilities during the pandemic years 2020 to 2022.[27] While many competitive industries were particularly hard hit by pandemic-related dislocations, Alberta regulated utilities appear to have avoided any significant harm and, indeed, experienced positive financial results throughout.

37. All parties provided evidence on relevant changes in macroeconomic and capital market conditions since the 2018 GCOC decision. Sections 4.1 to 4.4 that follow briefly summarize parties' submissions focusing on inflation, economic growth, bond yields and capital markets upon which the Commission has based its analysis and conclusions.

4.1 Inflation

38. Three utility witnesses (D. D'Ascendis, Dr. Villadsen and J. Coyne) identified high inflation as a primary risk to the economy in general, and to utility capital costs in particular. In their argument, ATCO-Fortis-Apex noted that inflation peaked in June 2022, at 8.1 per cent in Canada and remains above the BoC target range of one to three per cent.[28] The BoC, in response to higher inflation, increased its policy interest rate more than nine times since March 2022[29] and began quantitative tightening.[30] J. Coyne noted that while inflation has abated from its peak in 2022, inflationary pressures remain in the economy, which contributes to market instability.[31] D. D'Ascendis concluded that increased inflation and BoC policy interest rates, among other factors, reflected a higher level of market risk compared to 2018.[32] Dr. Villadsen noted that Moody's Investors Service revised its outlook for the U.S. regulatory utility sector to negative because higher inflation may limit a utility's ability to recover its costs absent regulatory support.[33] All utility witnesses viewed high inflation as a risk factor contributing to higher capital costs.

39. J. Thygesen stated in his evidence that he interpreted the BoC Governor Tiff Macklem's comments as foreshadowing a pause in the central bank's policy interest rate increases and that lower inflation was expected.[34] EPCOR challenged this claim by noting that policy interest rates

[26] See, for example, the oral testimony of D. Madsen for IPCAA on this point at Transcript, Volume 2, page 505. See also, Exhibit 27084-X0918, IPCAA argument, PDF page 18.

[27] Rule 005: *Annual Reporting Requirements of Financial and Operational Results.*

[28] Exhibit 27084-X0921, ATCO Electric Ltd. - The Utilities Argument, June 6, 2023, PDF page 5, paragraph 13.

[29] Exhibit 27084-X0921, ATCO Electric Ltd. - The Utilities Argument, June 6, 2023, PDF page 5, paragraph 13.

[30] The Commission notes that since the utilities submitted their argument on June 26, 2023, the BoC raised interest rates one additional time to 5.00% on July 12, 2023. Bank of Canada, https://www.bankofcanada.ca/core-functions/monetary-policy/key-interest-rate/

[31] Exhibit 27084-X0743, ENMAX Power Corporation – Reply evidence Concentric, April 4, 2023, PDF page 18.

[32] Exhibit 27084-X0390, AltaLink - EDTI evidence D'Ascendis written direct testimony, February 1, 2023, PDF page 120.

[33] Exhibit 27084-X0469.01, The Utilities Evidence – Villadsen, May 26, 2023, PDF page 24.

[34] Exhibit 27084-X0305, CCA evidence of Jan Thygesen, February 1, 2023, PDF page 10, paragraph 26.

had increased since J. Thygesen's evidence was submitted.[35] However, the Commission observes that inflation had, in fact, decreased in June 2023 from its June 2022 high.[36]

40. Dr. Cleary acknowledged that inflation was high in 2022, but argued that it peaked and that the BoC's expectation is for a return to sub three per cent inflation going forward. He supported his contention by stating that higher central bank policy interest rates are reducing inflationary pressures and, consequently, that central banks are now in the later stages of their quantitative tightening cycle.[37]

41. D. Madsen explained at the hearing that Alberta utilities are geographically and jurisdictionally constrained. Therefore, an Alberta-based utility's ability to recover its prudent costs is dependent on the regulator. His contention is that in a supportive regulatory environment, macroeconomic conditions do not materially affect a utility's ability to recover its costs and, therefore, a utility experiences no meaningful increase in risk due to inflation.[38]

4.2 Economic growth

42. Slower economic growth, due in part to the actions of the central banks, was another key issue identified by witnesses. Generally, all witnesses agreed that lower economic growth is likely in Canada in 2023 and 2024, with a higher probability of a recession.

43. The utility witnesses contended that investors are concerned about a recession, based on the current macroeconomic conditions. J. Coyne noted that the U.S. already experienced a technical recession in 2022, which demonstrated weaker fundamentals in the economy and that the BoC is projecting lower growth in 2023 and 2024.[39] J. Coyne also referred to the inverted yield curve – higher short-term bond yields than long-term bond yields in the U.S. and Canada – as an indicator of investor concerns about a recession.[40] D. D'Ascendis stated that recessions create more inherent risk for investors because negative economic growth may put at risk a commensurate return.[41] Dr. Villadsen cited the BoC's January 2023 Monetary Policy Report, which forecast Canada GDP growth of one per cent in 2023 and 1.8 per cent in 2024, which is lower than the 3.6 per cent growth experienced in 2022.[42] All utility witnesses argued that the macroeconomic uncertainty due to inflation and monetary tightening increases the cost of capital because the market is riskier in that state.

44. J. Thygesen agreed that while there is an elevated expectation of a recession in the U.S., citing the Conference Board, Federal Reserve St. Louis and Federal Reserve New York, were a recession to occur, some or all of the associated risks would be offset by lower interest rates.[43]

45. Dr. Cleary noted that Alberta's economic outlook was appreciably better than that of other provinces and, in fact, was unlikely to be recessionary. In support, he cited the Conference

35 Exhibit 27084-X0928, AltaLink and EPCOR Final Argument, June 26, 2023, paragraph 35.
36 Exhibit 27084-X0911, AltaLink and EPCOR Undertaking Appendix – Risk Measures Table Updated, June 8, 2023, worksheet 'Summary'.
37 Exhibit 27084-X0320.02, Cleary evidence, PDF page 25. Transcript, Volume 3, page 645, lines 13-18.
38 Transcript, Volume 2, page 505.
39 Exhibit 27084-X0315, Concentric evidence, PDF pages 31-35.
40 Exhibit 27084-X0585, Concentric Responses to UCA IRs, March 15, 2023, Concentric-UCA-2023FEB21-011.
41 Exhibit 27084-X0750, D'Ascendis rebuttal evidence PDF pages 18-19.
42 Exhibit 27084-X0469.01, Villadsen evidence, PDF page 22.
43 Exhibit 27084-X0736, Thygesen rebuttal evidence, PDF pages 15-17, paragraphs 40-42.

Board of Canada's December 2022 Alberta outlook, which predicts higher positive growth compared to the rest of Canada due to continued strength in the oil and gas sector.[44]

4.3 Bond yields

46. All witnesses agreed that as the BoC policy interest rate has increased, so too have bond yields – both corporate and government. There was also agreement among witnesses that the spread between A-rated utility bond yields and government bond yields (credit spread) has increased in the U.S. and Canada since 2018.

47. J. Coyne argued that the increased credit spread reflects investor concerns about the credit quality of utility bonds and general uncertainty about the broader economy.[45] Dr. Villadsen noted that the last time credit spreads were at this level or higher was in the spring of 2020 when the pandemic began riling financial markets, which is an indication of investor caution.[46] Dr. Cleary acknowledged that the credit spread is slightly higher than historical averages, measured since 2003.[47]

4.4 Capital markets

48. Over the course of the pandemic and into the recovery from it, Canadian and U.S. capital markets experienced volatility and, at times, counterintuitive results.

49. The utility witnesses argued that capital market volatility underwent periods of extreme flux during and after the pandemic due to complex market conditions, which reflected a greater level of investor uncertainty. D. D'Ascendis compared the average VIXI and VIX (indices that measure the Canadian and U.S. stock market's expectation of volatility) between 2018 and 2022, and observed that the indices were higher in 2022, reflecting increased volatility.[48] Dr. Villadsen explained that market volatility peaked during the early stages of the pandemic, declined from its pandemic highs, and increased again once the economy reopened.[49]

50. Dr. Cleary contended that in Canada the VIXI is currently below its normal range, while in the U.S. the VIX is slightly higher than usual.[50] He also pointed out that current corporate price earnings ratios and dividend yields are consistent with historical averages, suggesting that capital markets are healthy.[51]

5 Formulaic approach to determine ROE

5.1 The need for a formulaic approach to setting ROE

51. Over the past two decades, the Commission and its predecessors have employed various methodologies to set the approved ROE and deemed equity ratios. Prior to 2004, the

44 Exhibit 27084-X0320.02, Cleary evidence, PDF page 33.
45 Exhibit 27084-X0743, Concentric rebuttal evidence, PDF pages 22-23.
46 Exhibit 27084-X0469.01, Villadsen evidence, PDF page 33.
47 Exhibit 27084-X0320.02, Cleary evidence, PDF page 20.
48 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 120.
49 Exhibit 27084-X0469.01, Villadsen evidence, PDF page 35.
50 Exhibit 27084-X0320.02, Cleary evidence, PDF page 23. Note that Dr. Cleary refers to the VIXI as the "Canadian VIX."
51 Exhibit 27084-X0320.02, Cleary evidence, PDF page 22.

Commission's predecessors determined these parameters individually for each utility on a case-by-case basis.

52. In 2004, the Alberta Energy and Utilities Board (EUB), predecessor to the Commission, established a uniform (generic) ROE rate for all utilities and introduced a formulaic approach to determine subsequent ROE values.[52] This formulaic approach was used from 2005 to 2008. As a result of the global financial crisis in 2008-2009, in Decision 2009-216, the Commission discontinued the formulaic approach because it produced results that no longer accurately reflected changes in market circumstances. Specifically, the Commission observed that during the financial crisis, the traditional relationship between the risk-free rate and the required market return, on which the formulaic approach was based, did not hold.[53]

53. From 2009 through 2020, the Commission determined the ROE and deemed equity ratios by relying on evidence presented by parties in the GCOC proceedings. In doing so, the Commission retained the practice established in 2004 of setting a generic ROE for all utilities and accounting for any differences in business risks among the utilities through the deemed equity ratios. These parameters were established through rigorous regulatory proceedings, which included extensive oral hearings, where parties submitted a wide spectrum of economic and financial evidence. For the period 2021 to 2023, the Commission did not have fully litigated GCOC proceedings. Rather, it maintained the ROE of 8.5 per cent and a deemed equity ratio of 37 per cent (39 per cent for Apex) in light of the uncertainty arising from the pandemic and the limited access to stable, reliable, current and forward-looking economic and market data at the time.

54. Even though the Commission discontinued the formula in Decision 2009-216, it indicated that, to reduce regulatory burden, it would not "preclude a return to some sort of formula-based adjustment mechanism in the future when relationships in the capital markets have stabilized and are once again considered reasonably predictable."[54] After the effects of the 2008 financial crisis had abated, the Commission revisited the idea of implementing an ROE formulaic approach in almost every subsequent GCOC proceeding. However, in each of those instances, the Commission determined that a return to an ROE formulaic approach was not warranted. In earlier GCOC proceedings, this was due to the remaining volatility in the markets[55] and abnormal risk-return relationship attributable to ultra-low interest rates.[56] In later GCOC proceedings, the key obstacle was the onset of the pandemic and its associated economic dislocations.[57] Nevertheless, in every GCOC decision the Commission expressed its continued interest in exploring the reinstatement of an ROE formulaic approach given its administrative efficiency.

55. The Commission initiated the current proceeding with the view that a formulaic approach could offer a substantial improvement in efficiency with no loss in rigour or objectivity in determining the ROE component of the utilities' fair return. The fact that many jurisdictions have already adopted such an approach supported the Commission's view. In its directions on

52 Decision 2004-052.
53 Decision 2009-216, paragraph 417.
54 Decision 2009-216, paragraph 422.
55 Decision 2011-474, paragraph 165.
56 Decision 2191-D01-2015, paragraph 411.
57 Decision 24110-D01-2020: 2021 Generic Cost of Capital, Proceeding 24110, October 13, 2020, paragraphs 5, 7. Decision 26212-D01-2021: 2022 Generic Cost of Capital, Proceeding 26212, March 4, 2021, paragraph 18.

procedure letter,[58] the Commission asked whether ERP-based formulaic approaches, such as those adopted by the Ontario Energy Board (OEB) and the Commission's predecessor, the EUB, were an appropriate starting point for considering the reintroduction of an ROE formulaic approach in Alberta.

56. Most, if not all parties to this proceeding, were relatively unenthusiastic about, if not rather firmly opposed to, any Commission departure from holding periodic, fully litigated GCOC proceedings and moving instead towards adopting a formulaic approach for setting the ROE in 2024 and subsequent years. Nonetheless, over the course of this proceeding, parties were helpful to the Commission and provided their recommendations on specific parameters of a formulaic approach should the Commission ultimately decide to implement one, even though this was not their preference.

57. After considering various perspectives and parties' views, the Commission finds it will implement the formulaic approach for determining the ROE, starting in 2024. For the reasons set out below, the Commission is of the view that this approach offers a balanced and pragmatic solution to several pressing concerns.

58. Among the most important advantages of adopting a formulaic approach is the elimination of regulatory lag in establishing regulated rates. By setting the approved ROE on a prospective basis, the formulaic approach avoids delays, ensures that rates better reflect current economic conditions, offers greater regulatory certainty to utilities and customers alike, mitigates the risk of adverse credit rating actions, and reduces volatility in cash flows. Every one of these concerns has been raised by parties in past GCOC proceedings, including the most recent fully litigated one in 2018, as being among the negative consequences of regulatory lag.[59]

59. Furthermore, the formulaic approach enhances transparency and predictability in the regulatory process. It streamlines decision making by providing a clear and objective mechanism for determining the approved ROE, while reducing the need for protracted, resource-intensive, and costly litigated proceedings.[60] By doing so, it not only saves significant time and resources for both customers and utilities, but also aligns with the Commission's broader goal of improving efficiency and reducing regulatory burden.

60. The Commission reaffirms its commitment to exercising regulatory judgment, addressing concerns expressed by many parties that there must be an opportunity to review the ROEs produced by the formulaic approach for reasonableness as a safety feature. Should any party determine that the formulaic approach no longer results in just and reasonable outcomes, Section 5.4 below outlines a mechanism by which parties can apply to the Commission for corrective action.

58 Exhibit 27084-X0034, paragraph 9.

59 Decision 22570-D01-2018, Section 9.3.2.4, Regulatory lag.

60 For example, for the most recent fully contested GCOC proceeding in 2018, the Commission approved cost awards amounting to just over $1.5 million. The Commission's scale of costs does not cover the full costs of most experts and legal counsel for proceedings, and the amounts claimed and awarded therefore do not reflect the real cost of participation. A review of actual invoices submitted in the 2018 GCOC costs proceeding indicates that parties to that proceeding spent a total of about $4 million on external legal counsel and experts. This does not account for the significant costs incurred by the parties internally, nor the costs of other parties (such as the UCA) who do not submit cost claims to the Commission, nor the costs of the Commission itself and its processes (costs which are ultimately borne by customers).

61. The record in this proceeding is clear that a variety of formulaic approaches are used in other jurisdictions. Experience in these jurisdictions, notably Ontario, suggests that a properly calibrated formulaic approach can operate effectively over a sustained period of time, producing ROE results that meet the fair return standard, without the associated costs and complexities of a fully litigated process. If a formulaic approach produces reasonable outcomes and its adoption avoids one or two exhaustive fully litigated proceedings, thereby contributing to the reduction in regulatory burden and cost, this would be a significant advancement compared to the current approach of initiating litigated cases every two to three years.

5.2 ROE formulaic approach

62. As noted in the previous section, in its directions on procedure letter,[61] the Commission put to parties the ERP-based formulaic approaches adopted by the EUB and the OEB as possible starting points for reintroducing an ROE formulaic approach.

63. In Decision 2004-052, the EUB adopted a single-factor formulaic approach for setting the generic ROE based on 75 per cent of the change in long-term GoC bond yield:

$$ROE_t = 9.60\% + 0.75 \times (YLD_t - 5.68\%)$$

64. The EUB established a generic ROE for the year 2004 at 9.60 per cent, which served as the initial or "base" ROE value in the above formula. An adjustment factor of 0.75 was determined through an assessment of the proposals submitted by the involved parties at the time. The final element of the formula encapsulated variation in forecast long-term Canada bond yield, calculated as the difference between the current year Consensus Forecasts[62] (denoted as YLD_t in the formula above) and the "base" yield of 5.68 per cent that was set based on forecasts deemed reasonable in the 2004 decision.

65. In its Decision EB-2009-0084,[63] the OEB approved the following formula:

$$ROE_t = 9.75\% + 0.5 \times (\mathrm{LCBF}_t - 4.25\%) + 0.5 \times (\mathrm{UtilBondSpread}_t - 1.415\%)$$

66. The OEB's formula established a "base" ROE of 9.75 per cent for the year 2010. The OEB approved an adjustment factor of 0.5 with respect to changes in long-term GoC bond yield, reducing it from the previously established value of 0.75. This change was made to decrease the formula's sensitivity to changes in government bond yields, which could be influenced by monetary and fiscal conditions unrelated to shifts in the utility cost of equity. In addition, the OEB acknowledged the existence of a statistically significant correlation between corporate bond yields and the cost of equity, and incorporated an element related to utility bond yields with an adjustment factor of 0.5.

67. As discussed in the previous section, while no utility witnesses expressly supported the use of a formula to determine the ROE, they provided evidence on specifications for a formulaic

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[61] Exhibit 27084-X0034, paragraph 9.
[62] Consensus Forecasts are published by Consensus Economics.
[63] Ontario Energy Board Decision EB-2009-0084: Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009.

approach should the Commission decide to proceed with one. Such evidence was also provided by the customer groups to a certain degree.[64]

68. Concentric indicated that, "If the AUC decides on an ERP approach, then the formula used in Ontario that includes both government bond yields and utility credit spreads is a reasonable compromise."[65] D. Madsen[66] expressed a similar view. As well, Dr. Villadsen recommended that changes in the long GoC bond yield and changes in the utility bond yield spread be included in the formula, much as they are in the OEB's methodology, as both factors influence the cost of equity.[67]

69. D. D'Ascendis found an ERP-based approach to be a suitable starting point for developing a formula to adjust an appropriately derived "base" ROE. Of the two examples set forth by the Commission, he found the OEB's two-factor adjustment formula to be superior to the one-factor adjustment formula used by the EUB, as it more closely reflects the relationship between interest rates and the ERP.[68] However, in his evidence, D. D'Ascendis recommended that the Commission broaden the basis of the ROE adjustment mechanism and use market data in the DCF model and capital asset pricing model (CAPM) for a group of risk comparable companies in lieu of a simple ERP model that is based on the change in bond yields.[69]

70. In his evidence, Dr. Cleary, submitted that the ERP-based approach is the most suitable formulaic method for determining allowable ROEs. He asserted that this approach is widely adopted and, in his perspective, it stands as the sole viable option. Furthermore, Dr. Cleary underscored that the OEB formula can be viewed, in essence, as a modified version of two ERP models, namely the CAPM and bond yield plus risk premium, which are commonly relied upon in assessing the cost of equity, or the approved ROEs, during cost-of-capital hearings.[70]

71. Based on the submissions of parties, the Commission adopts an ERP-based two-factor formulaic approach similar to the one utilized by the OEB. Specifically, the Commission approves the following two-factor formula to determine the ROE for 2024 and future test periods on an annual basis:

$$ROE_t = ROE_{base} + w_1(YLD_t - YLD_{base}) + w_2(\mathrm{SPRD}_t - SPRD_{base})$$

where:

ROE_t is the approved ROE for the test year t

ROE_{base} is the "base" ROE, that is the approved notional ROE

w_1, w_2 are adjustment factors for changes in long-term GoC bond yield and utility bond yield spread, respectively (referred to on the record as VAR4 and VAR7)

64 The CCA did not provide evidence regarding each variable of the two-factor formula.
65 Exhibit 27084-X0315, PDF page 21.
66 Exhibit 27084-X0292, PDF page 6.
67 Exhibit 27084-X0469.01, PDF page 9.
68 Exhibit 27084-X0047, PDF page 5.
69 Exhibit 27084-X0057, PDF pages 9-10.
70 Exhibit 27084-X0320.02, PDF pages 91-92.

YLD_t and YLD_{base} are long-term GoC bond yields for the test year and base period, respectively (VAR2 and VAR1)

$SPRD_t$ and $SPRD_{base}$ are utility bond yield spreads for the test year and base period, respectively (VAR6 and VAR5)

72. Based on the approvals in Section 6 of this decision, the generalized formulaic approach above can be specified as follows:

$$ROE_t = 9.0\% + 0.5 \times (\mathrm{YLD}_t - 3.10\%) + 0.5 \times (\mathrm{SPRD}_t - \mathrm{SPRD}_{base})$$ [71]

73. In Decision 2011-474,[72] the Commission noted that this type of a formula has advantages over the previously utilized single-factor formula, as it is likely to better reflect any fluctuations in capital market conditions.[73] Based on the record of this proceeding, the Commission maintains this view.

74. Parties in this proceeding highlighted that the introduction of the utility bond yield spread component was a major improvement to the OEB formula that contributed to its longevity and acceptance of the resulting ROEs. Dr. Villadsen stated academic literature supports the basic concept that changes in credit spreads serve as a meaningful directional indicator of relative changes in the prevailing market equity risk premium.[74] Concentric indicated that the OEB formula has generally provided a more reasonable return in most of the years since the utility bond yield spread component was introduced because it captures industry-specific changes in risk that are otherwise not captured by changes in the government or risk free bond yield.[75] N. Martin pointed out the only review that the OEB conducted since 2009 was completed in 2016 and did not result in any change.[76] The Commission agrees with all of these observations.

5.3 Annual process to determine the ROE through the formulaic approach

75. From 2005 to 2008 when the EUB used a formula, the EUB initiated a proceeding every year to calculate the approved ROE for the subsequent test year beginning January 1. The EUB relied on the forecast 10-year Canada bond yield for a test year published in the Consensus Forecasts issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.[77] The results of the update were made available to the public by way of an order released at or near the end of November each year.

76. A similar process is used by the OEB to update its two-factor formula adopted in EB 2009-0084. More specifically, the cost-of-capital parameters are based on the data for September of the preceding year (i.e., three months in advance of the January 1 effective date for

71 The Commission has determined that it will use the bond yield spread for the month of February 2023, using the method set out in Section 6.5.3 of this decision.
72 Decision 2011-474: 2011 Generic Cost of Capital, Proceeding 833, Application 1606549, December 8, 2011.
73 Decision 2011-474, paragraphs 164-165.
74 Exhibit 27084-X0469.01, PDF page 80.
75 Exhibit 27084-X0315, PDF page 110.
76 Exhibit 27084-X0316, PDF page 31.
77 Decision 2004-052, PDF page 36.

rates), using the long-term GoC bond forecast and A-rated utility bond yield spread. The results of the update are made available to the public during the months of October to November.

77. In this proceeding, parties generally favoured the approach currently taken by the OEB[78] or the annual update process previously adopted by the EUB.[79] Overall, parties emphasized the need for transparency in the calculations with the results being made available to the public in advance of the ROE taking effect.

78. Given the preference of parties, and to reduce regulatory burden, the Commission will adopt a practice similar to the one it employed between 2005 and 2008. The Commission will initiate a proceeding in early November of each year, in which it will provide calculations of the upcoming year's ROE based on the October data for the forecast long-term GoC bond yield and prevailing utility bond yield spread in comparison to their base values. More specifically, as set out in Section 6.5:

(i) The forecast long-term GoC bond yield will be calculated as the weighted average of (i) the 30-year GoC bond yield forecasts published by RBC, TD and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (ii) the naïve forecast representing the average long-term GoC bond yield[80] over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.

(ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield[81] and the long-term GoC bond yield[82] over the period October 1 to October 31 of the year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

79. Parties will have the opportunity to comment on the Commission's ROE calculations and provide input on any identified discrepancies. The Commission will then issue a decision at the end of November with a final approved ROE for the upcoming year resulting from the formulaic approach approved in this decision.

80. The ROE calculated by the formulaic approach for each test year will come into effect on January 1 of that year.

5.4 Periodic reviews of formulaic approach

81. Employing a formulaic approach to determine annual changes in the ROE requires periodic evaluation to ensure that the ROE produced by the formula continues to be in alignment with the standards for achieving a fair return.

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78 Exhibit 27084-X0292, PDF pages 51-52. Exhibit 27084-X0315, PDF page 116. Exhibit 27084-X0320.02, PDF page 12, and Section 5, PDF pages 91-98.
79 Exhibit 27084-X0469.01, PDF page 105. Exhibit 27084-X0390, PDF page 117.
80 Bank of Canada CANSIM Series V39056.
81 Bloomberg Series C29530Y.
82 Bank of Canada CANSIM Series V39056.

82. The Commission solicited input on the process to assess whether the formulaic approach continues to generate a reasonable ROE. The Commission also sought parties' views, should questions arise as to the continued reasonableness of the results produced by the formulaic approach, on necessary remedial steps to be taken to ensure that an ROE satisfying the fair return standard is restored on a go-forward basis.

83. In their submissions, parties identified two main approaches to reviewing the reasonableness of the ROEs produced by the formulaic approach. The first approach involves a predetermined periodic review of the ROEs determined formulaically, every three to five years, regardless of economic conditions. The second approach contemplates mid-term reopeners initiated either by the Commission or upon application by any interested party (i.e., utility or intervener). In the case of mid-term review applications filed by interested parties, the burden of establishing that a full scale review of the reasonableness of the formula's results is warranted would reside with the applicant. As a variant of the second approach, some parties proposed proactively adopting measures such as deadbands, ceilings and floors around the ROE in order to accomplish the following ends: (i) automatically trigger reopeners when formulaic outcomes depart from the previous year's results by a specified margin; and (ii) limit potentially frivolous review applications for relatively minor changes in ROE results from one year to the next.[83] Other parties recommended that the Commission refrain from prescribing fixed thresholds for reviewing formula results and, instead, retain the discretion to review the ROEs resulting from the formulaic approach as and when required.[84]

84. In the Commission's view, the two approaches are not mutually exclusive and elements of both can be employed to ensure that the formulaic approach continues to produce just and reasonable results.

85. The Commission has determined that a periodic review every five years strikes an optimal balance. This duration ensures the ongoing alignment of the formula-derived ROE with the established fair return standard, while maintaining the objectives of regulatory efficiency and certainty. The Commission emphasizes that this review process does not necessarily imply a fully litigated GCOC process resulting in a resetting of the formula's parameters, including base ROE. Rather, the Commission will initially seek input from parties on the preliminary assessment of the formula's continued capacity to generate a fair ROE. The Commission's decision on whether to undertake a comprehensive review of either the ROE in general, or the ROE formulaic approach in particular, will be informed by the feedback received on the preliminary matters. The Commission will retain full discretion in determining the process to be followed.

86. In line with this approach, the Commission expects to conduct its first assessment in 2028. Any modifications resulting from this evaluation will subsequently influence the ROE for the 2029 rate year and beyond.

87. In addition to providing for mandatory five-year reviews (without predetermining in advance the length, scope or complexity of the review process), the Commission also sees merit in allowing for mid-term reopeners either at its own initiative or upon application by interested parties if there are compelling grounds to believe that the ROE resulting from the formulaic

[83] Exhibit 27084-X0924, ENMAX argument, PDF page 31, paragraphs 141-142. Exhibit 27084-X0926, UCA argument, PDF page 34, paragraph 123.
[84] Exhibit 27084-X0928, AltaLink/EPCOR argument, PDF page 28, paragraph 73.

approach may no longer be just and reasonable. The Commission envisions mid-term reopeners initiated by parties would be subject to a two-stage review process. In order to move from Stage 1 to Stage 2 of the review process, applicants would bear the burden of establishing on a balance of probabilities that there exist one or more sufficiently compelling reasons for the Commission to question whether its formulaic approach to setting utility ROEs remains, and/or produces results that continue to be, just and reasonable. In the Commission's view, reliance on such a test is likely to quickly dispense with frivolous applications, while still allowing for a broad range of concerns that would justify a deeper examination of the continued reasonableness of the formulaic approach.

88. The Commission is not persuaded, however, that the potential benefits of establishing thresholds that would automatically trigger offramps for, or reasonableness reviews of, the formulaic approach outweigh the disadvantages of adopting such measures. As noted by AltaLink/EPCOR and Dr. Cleary, respectively: the "Commission should not attempt to predetermine and fix specific thresholds for reopeners or offramps"[85] and "given the difficulty capturing all scenarios where a review may be warranted, the need for a reopener may ultimately be best left to a matter of judgment."[86] In addition, the Commission notes that it has been almost 15 years since it last relied on a formulaic approach to set utility ROEs. The formulaic approach approved in this decision is also different from the last formula relied on by the Commission. As a result, the Commission considers it to be in the public interest – at least until it acquires greater familiarity with how the formula operates under a variety of different circumstances – that the Commission maintain the maximum degree of discretion in determining how and when the formulaic approach should be reviewed when a question arises as to its ability to meet the fair return standard both over time and in light of ever-changing market conditions.

89. Closely related, the Commission is concerned that any mechanical reliance upon predetermined ROE deadbands, ceilings and floors may inadvertently result in both false-positives (i.e., conducting unnecessary reviews) and false-negatives (i.e., failing to undertake necessary reviews).

5.5 Periodic reviews of deemed equity ratios

90. In order to meet the fair return standard, the Commission has to not only establish a fair ROE, but also determine which proportion of capital invested by the utilities should be financed through shareholder equity and which should be financed through debt. The proportion of capital to be financed by equity is referred to as the "deemed equity ratio." This represents that portion of total invested capital upon which a utility is allowed to earn its Commission-determined target rate of return. The Commission's findings on the approved deemed equity ratios for Alberta utilities are set out in Section 7 of this decision. In this section, the Commission addresses how often these approved ratios should undergo a reasonableness review.

91. The Commission solicited input from parties on whether it was necessary to update deemed equity ratios while a formulaic approach to determine ROE is in operation and, if so, how frequently and pursuant to what process.

[85] Exhibit 27084-X0928, AltaLink/EPCOR argument, PDF page 28, paragraph 73.
[86] Exhibit 27084-X0926, PDF page 34, paragraph 124.

92. Consistent with the timing recommended for mandatory reviews of the continued reasonableness of formulaically updated ROEs, experts for several parties (including J. Coyne,[87] D. D'Ascendis,[88] Dr. Villadsen[89] and Dr. Cleary[90]) suggested that the reasonableness of deemed equity ratios also be reviewed at the same time (i.e., every three to five years). R. Bell, meanwhile, suggested that equity thickness be reviewed each year concurrently with the formulaic update to ROEs, while D. Madsen proposed several specific conditions for updating equity thickness ratios going forward.

93. The Commission acknowledges the importance of ensuring predictability of the approved level of the deemed equity ratios moving forward, particularly while utilizing a formulaic approach to determine ROE. Since the deemed equity ratio influences the financial structure of a utility and, therefore, the ROE calculation, the Commission agrees with those parties that advocated for a concurrent review of both elements.

94. The Commission does not consider an annual assessment of deemed equity ratios as proposed by R. Bell to be warranted or cost-justified. Similarly, the Commission does not find merit in imposing upon electric (and presumably, gas) utilities the many conditions D. Madsen[91] recommended be satisfied before new equity ratios can be approved.

95. Instead, the Commission will institute a mandatory review of deemed equity ratios every five years consistent – and contemporaneous – with the approach outlined in Section 5.4 that the Commission will employ for the periodic evaluation of the formulaic approach. As with the latter, the length, scope and complexity of the equity thickness review process will not be predetermined but, rather, will depend on circumstances prevailing at that time.

96. Additionally, the Commission recognizes the value of permitting mid-term reopeners, either at its own discretion or upon application of interested parties, if compelling circumstances suggest that the deemed equity ratio is no longer reasonable. When initiated by parties other than the Commission, such mid-term reopeners will be subject to a two-stage review process similar to that for reviews of the formulaic approach.

6 Notional ROE and other formula variables

6.1 Overview

97. The Commission must determine a fair return for the utilities under its jurisdiction as part of fixing just and reasonable rates. In Section 5 of this decision, the Commission determines that it will adopt a formulaic approach to setting the ROE starting in 2024. As also set out in that section, the formula requires a notional ROE as a starting point. This notional ROE is determined with the same rigour and process used to determine ROE in prior fully litigated proceedings, and considers a variety of approaches, models and directional indices. However, this ROE will not be reflected in customer rates; rather, its sole purpose is to serve as an input to the approved

87 Exhibit 27084-X0315, PDF page 7.
88 Exhibit 27084-X0390, PDF page 118.
89 Exhibit 27084-X0469, PDF pages 32-33.
90 Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 13, lines 17-19.
91 Exhibit 27084-X0292, PDF page 65.

formula. The ROEs produced by the formula will be approved on a final basis effective January 1 of each test year.

98. This section is organized as follows. In Section 6.2, the Commission discusses the extent to which the market data for the comparator group of utilities can be used to inform the determination of cost-of-capital parameters for the Alberta utilities. Section 6.3 determines a risk-free rate as an input to the ERP models, such as the CAPM, and the formulaic approach adopted by the Commission in this decision. In Section 6.4, the Commission determines the notional ROE by analyzing results of various financial models that were presented by proceeding participants. Finally, in Section 6.5, the Commission determines the values for the first and second factors of the formulaic approach to account for changes in GoC bond yields and changes in utility bond yield spread.

6.2 Comparability of representative utilities

99. In past GCOC proceedings, the Commission has frequently expressed concern with the wide range of conflicting evidence and polarized opinions on how it should approach setting a fair return on capital for the utilities it regulates. Oftentimes there was prolonged debate on the degree to which various utility comparator groups that parties relied on to construct models to estimate the ROE were representative of the Alberta utilities. An example of this is the 2018 GCOC proceeding, where parties proposed at least 13 different proxy groups consisting of various subsets of North American utilities.[92]

100. In order to address these concerns the Commission implemented a process to establish a comparator group of representative utilities that are similar to the Alberta utilities, for the purpose of informing the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE (the comparator group process).[93] The outcome of the comparator group process was that the parties reached a consensus on screening criteria and a comparator group of representative utilities resulting from the application of the screening criteria.[94]

101. The weight to be assigned to the specific utilities within the comparator group was not determined in the comparator group process. Instead, the Commission acknowledged that the parties did not agree that all companies in the comparator group are truly comparable to the Alberta utilities, and confirmed that the comparability of and weight to be assigned to the specific companies in the comparator group remained an issue to be determined in the proceeding.[95] The Commission specifically noted that parties could present evidence that certain companies in the comparator group should not be given any weight at all.[96]

102. The Commission is not persuaded by the argument that certain of the representative utilities in the comparator group lack comparability due to the involvement of their parent corporations in generation, retail or other unregulated business sectors. Concerns of this nature

92 Exhibit 27084-X0038, paragraph 8.
93 Exhibit 27084-X0034, paragraph 8.
94 Exhibit 27084-X0268.01, PDF page 4.
95 Exhibit 27084-X0239.01, PDF page 1, paragraph 2; Exhibit 27084-X0255, PDF page 4, paragraph 12; Exhibit 27084-X0268.01, PDF page 4.
96 Exhibit 27084-X0255, PDF page 4, paragraph 12.

were addressed by the screening criterion, which excluded utilities from the comparator group if less than 80 per cent of their assets are tied to rate-regulated activities.

103. While the Commission finds that the U.S. companies have higher business risks than the Alberta utilities, for the purpose of establishing the comparator group, the Commission accepts the utilities' evidence that it is appropriate to include U.S. utility holding companies. The reasons for this are: (i) the relatively limited number of publicly traded Canadian utility companies; (ii) the prevalence of U.S. business operations among many publicly traded Canadian utilities; and (iii) investors' tendency to consider utility investment opportunities in both the U.S. and Canada.[97] Further, the Commission remains of the view that it is reasonable to consider the U.S. market return data given the globalization of the world economy and integration of North American capital markets.[98] Notwithstanding these findings, none of the Alberta utilities raises capital directly in the equity market, or operates outside of Alberta unlike a number of companies in the comparator group, which are holding companies and can operate anywhere.

104. After considering the evidence presented in this proceeding, the Commission acknowledges the utilities in the comparator group are not identical to the Alberta utilities, but concludes they are sufficiently comparable for use in various financial models. However, and as set out in in this section and Section 6.4.5, the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities. Accordingly, the Commission retains the view expressed in the 2018 GCOC decision that a significant amount of judgment must be applied by the Commission when interpreting data from the representative utilities to establish the ROE required by investors in the Alberta utilities.[99]

6.3 Measure of the risk-free rate

105. The risk-free rate is an important component of ERP models, such as the CAPM, and the formulaic approach approved by the Commission in Section 5. ERP-based models are based on the fundamental assumption investors require higher returns for bearing higher risk; or, in other words, investors require a premium for bearing risk that exceeds the risk-free rate. The Commission has accepted in the past that there is an inverse relationship between the risk-free rate and the risk premium required by equity investors: as interest rates increase (decrease), risk premium decreases (increases).

106. Consequently, given these fundamental relationships inherent in ERP-based models, the risk-free rate of 3.10 per cent approved in this section is used for three purposes in this decision: (i) as a base forecast long-term GoC bond yield (YLD_{base}) against which future expected changes in risk-free rates are measured to adjust the ROE in accordance with the approved formula; (ii) as a factor to determine the base ERP underlying the approved formula; and (iii) a measure of the risk-free rate in the CAPM model used to estimate the notional ROE.

107. Consistent with past GCOC proceedings, parties uniformly submitted that yields on long-term government bonds are considered to be default free and therefore are an appropriate measure of the risk-free rate. There was general agreement the 30-year Canada bond yield be

97 Exhibit 27084-X0937, Utilities reply argument, PDF page 12, paragraph 32.
98 Decision 22570-D01-2018, paragraph 275; Decision 20622-D01-2016: 2016 Generic Cost of Capital, Proceeding 20622, October 7, 2016, paragraph 302; Decision 2009-216, paragraph 200.
99 Decision 22570-D01-2018, paragraph 275.

used, as the 30-year term to maturity is consistent with the long-term character of the underlying utility assets.

108. Parties were also consistent in the view that the bond yield used to approximate the risk-free rate be forward-looking, in keeping with the forward-looking nature of a cost-of-capital determination. However, there were differences in how the forecast 30-year Canada bond yield should be determined and the data sources used. Submissions of parties as to the forecast long-term GoC bond yield, term to maturity, and source of data are summarized below in Table 1.

Table 1. Risk-free rate recommendations

Witness (sponsoring party)	Recommendation	Data source	Yield
Dr. Villadsen (ATCO/Apex/Fortis)	Use projection of the 10-year Canada bond yield plus the long-term average maturity premium between 10-year and 30-year Canadian bonds.[100]	Consensus Economics[101]	3.85% as of November 7, 2022[102]
Concentric (ENMAX)	Use 10-year bond yield forecast and add the average spread between 10- and 30-year government bond yields.[103]	Consensus Economics	3.59%[104]
D. D'Ascendis (AltaLink/EPCOR)	Use an average of three-month-out and 12-month-out forecasts of the 30-year Canada bond yield.[105] [106]	RBC Financial Markets Monthly and TD Economics Forecast	2.89% as of December 31, 2022
D. Madsen (IPCAA)	Use current 30-year GoC bond yield as this point in time observation is consistent with a number of published forecasts of the 30-year Canada bond yield for 2023-2024.[107]	RBC Financial Markets Monthly, Kroll	2.95% as of January 13, 2023
Dr. Cleary (UCA)	Use the actual prevailing 30-year government bond yield at the time the initial (or base) ROE is set.[108]	-	2.85% as of January 19, 2023[109]
J. Thygesen (CCA)	No submission made on the rate or approach to quantify this variable.	-	Maximum risk-free rate for 2024 be set at 3%[110]

109. The Commission accepts the submissions of parties that the 30-year term to maturity best reflects the long-term character or useful life of the underlying utility assets. The Commission

100 Exhibit 27084-X0469, PDF page 71.
101 Consensus Economics publishes long-term [10-year] interest rate projections twice a year, in April and in October. Transcript, Volume 2, page 114, lines 2-6.
102 Exhibit 27084-X0469, PDF page 41. 3.85% represents the average of yield on a 10-year Canadian government bond in February 2023 (3.5%) and November 2023 (3.4%) as reported by Consensus Forecasts on November 7, 2022, publication, adjusted upwards by Dr. Villadsen by 40 basis points to represent maturity premium for the 30-year over the 10-year Canadian government bond.
103 Exhibit 27084-X0315, PDF page 101.
104 Exhibit 27084-X0315, PDF page 61, Concentric evidence. While Concentric did not recommend a specific numerical value for the base forecast long-term GoC bond yield, it used an average of the Canadian (3.59%) and U.S. (3.87%) risk-free rates of 3.73% in its estimation of the notional ROE and implied ERP in its filed evidence.
105 Exhibit 27084-X0390, PDF page 24.
106 Exhibit 27084-X0610, AML_EPCOR-AUC-2023FEB21-001, PDF pages 1-3.
107 Exhibit 27084-X0292, PDF page 14.
108 Exhibit 27084-X0320.02, PDF pages 6-7.
109 Exhibit 27084-X0605, UCA-AUC-2023FEB21-012, PDF page 31.
110 Exhibit 27084-X0713, paragraph 44.

notes that parties provided various empirical and capital markets resources that supported the rationale for matching the useful life of the asset and the term to maturity of the risk-free rate.[111]

110. In keeping with the prospective or forward-looking nature of the determination of the cost of capital and prior Commission practice, it is appropriate to use a forecast of the 30-year Canada bond yield submitted on the record of this proceeding. The Commission finds that a direct forecast of the 30-year Canada bond yield from Canadian major banks is simpler and more transparent than the approach recommended by Dr. Villadsen and Concentric, which uses the Consensus Economics forecast 10-year GoC bond yield and adjusts it by adding the average spread between 10- and 30-year government bonds. The need for this adjustment arises from the fact that Consensus Economics, on which Dr. Villadsen and Concentric rely, does not publish a forecast for the 30-year Canada bond yield. Similar adjustments have been used by the OEB and EUB for their formulas because of reliance on Consensus Forecasts.

111. The 30-year Canada bond yield forecasts are published by large, reputable Canadian financial institutions such as “the Big Six” banks. In the Commission’s view, these forecasts are of comparable quality to the forecasts published by Consensus Economics. In fact, the Consensus Economics forecast is an average of estimates from various sources, including Canadian major banks. However, using direct forecasts of the 30-year Canada bond yield eliminates the need to make additional estimates and adjustments to the 10-year forecast for which there is no single, standardized approach. In addition, these forecasts are publicly available without cost. For simplicity, the Commission considers that averaging the forecasts from three banks, RBC, TD and Scotiabank, is sufficient. Should a forecast from one or more of these banks be unavailable, there are three additional major banks from which a forecast may be obtained as a substitute.

112. In addition to relying on bond yield forecasts published by the three banks, the Commission accepts in principle the approach of D. Madsen and Dr. Cleary to use a naïve forecast,[112] using the actual 30-year GoC bond yield to inform an estimate of the future 30-year GoC bond yield. The Commission has relied on this approach in past GCOC decisions to temper published forecasts because it accepted they tend to overestimate changes in interest rates. In this proceeding, representatives of customer groups made a similar point.[113] However, the Commission considers it is better to use the average actual long-term GoC bond yields for an entire month rather than the yield that prevailed on any a single day in that month, as was done by Dr. Cleary and D. Madsen, to smooth out the daily volatility.

113. The Commission will use the bank forecasts published in February 2023 provided by D. D’Ascendis, as they were the most recent bank forecasts of long-term GoC bond yields provided on the record. For consistency, the Commission will use the average actual long-term GoC bond yield in February 2023 for the naïve forecast.

114. For the reasons above, the Commission finds it reasonable to set the forecast risk-free rate to be 3.10 per cent, equal to the average of the 30-year Canada bond yield estimates for the forecast period Q1 2023 to Q4 2023 of RBC at 2.90 per cent, TD at 3.08 per cent, and

111 Exhibit 27084-X0390, D’Ascendis evidence, PDF pages 22-24.

112 An estimating technique wherein the actual values from the previous period are employed as the forecast for the current period, without adjusting them or identifying causal factors.

113 Exhibit 27084-X0292, Evidence of Dustin Madsen, PDF page 14; Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 39.

Scotiabank at 3.26 per cent as of February 2023[114] as well as a naïve forecast of 3.16 per cent representing the average actual long-term GoC bond yield for the period February 1 to February 28, 2023.[115]

6.4 Notional ROE

115. In this section, the Commission determines the notional ROE of 9.0 per cent using current market data and considering results of well-known and widely accepted empirical models to estimate the required return such as the CAPM, constant growth discounted cash flow (DCF), and multi-stage DCF.

116. Under the formulaic approach, the notional ROE serves as the base metric against which future adjustments arising from changes in forecast long-term Canada bond yields and utility bond yield spreads are made and captures the estimated forecast ERP that is commensurate with the base forecast long-term GoC bond yield.[116] In turn, the notional ROE can be defined as the sum of the base forecast long GoC bond yield (YLD_{base} in the formula) and the base forecast ERP.

117. Parties recommended a notional ROE and estimated the ERP based on their respective risk-free-rate submissions. Table 2 sets out the notional ROE and ERP recommendations by party.

Table 2. Notional ROE and ERP recommendations by party

Witness (sponsoring party)	Notional ROE (%)	ERP[117] (%)	Empirical approaches used	Comments
Dr. Villadsen (ATCO/Apex/Fortis)[118]	10.0	5.68	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommended range for notional ROE is 9.2% to 10.4%
Concentric (ENMAX)	9.50	5.67	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommendation reflects M-DCF and CAPM using historical MERP.[119]
D. D'Ascendis (AltaLink/EPCOR)	10.30	6.44	CAPM/ECAPM, DCF, M-DCF, Predictive Risk Premium Model, Adjusted Total Market Approach	Recommended range for notional ROE is 9.80% to 10.80%.[120]
D. Madsen (IPCAA)[121]	7.70	4.75	CAPM, DCF and M-DCF	Recommendation is simple average of CAPM and DCF models (7.51% and 7.90%)
Dr. Cleary (UCA)	6.75	3.90	CAPM, DCF, M-DCF and Utility Bond Risk Premium Analysis	-

114 Exhibit 27084-X0610, PDF page 2 with reference to Exhibit 27084-X0611 providing supporting data.
115 This is a Commission calculation using the Bank of Canada website provided in Exhibit 27084-X0613, UCA-UTILITIES-2023FEB21-008, PDF page 11. https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010013901
116 Exhibit 27084-X0268.01, PDF page 3.
117 Includes 0.50% flotation allowance.
118 Exhibit 27084-X0921, PDF page 2. Recommendation also assumes 40% deemed equity for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, with additional equity thickness for ATCO Electric Transmission (42%), Apex (44%) and Fortis (43%). If deemed equity is set at 37%, then the ROE should be set 25 to 40 basis points above the recommendation for 40% equity or 10.25% to 10.40%. Recommended notional ROE and VAR3 include 20 basis point risk adder.
119 Exhibit 27084-X0315, PDF page 4. If deemed equity is set at 40%, then the ROE should be set at 10%.
120 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 9.
121 Exhibit 27084-X0292, PDF page 6.

118. As was the case in past GCOC proceedings, parties in this proceeding presented the Commission with a wide range of recommendations for notional ROE and ERP. In addition, there is significant variability in the results obtained by applying each of the empirical models, all of which have been previously considered by the Commission.

119. In sections 6.4.1 to 6.4.4 the Commission briefly describes the empirical models, including the key variables that must be specified and associated measurement issues. In Section 6.4.5, the Commission considers the results of the models and exercises its judgment, having regard to all of the evidence in this proceeding, to determine the notional ROE and ERP. The Commission's conclusion on the notional ROE for the formula takes into account that the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities.

6.4.1 The CAPM

120. The CAPM is based on the relationship between the returns investors expect to receive on their investments in an asset and the systematic (or non-diversifiable) risk faced by that asset. The model is premised on a relationship where the required future return on the asset is proportional to that asset's risk relative to the market. This risk is measured by the asset's "beta."

121. The CAPM can be represented by the following formula:

$$Rs = Rf + \beta[Rm-Rf]$$

where:

Rs is the required return on the common stock;
Rf is the risk-free rate;
Rm is the return on the market portfolio;
Rm – Rf is the market equity risk premium (MERP); and
β, or beta, is the risk measure for the common stock.

122. Each of the variables in the CAPM equation must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The CAPM recommendations of parties are summarized in the following table.

Table 3. CAPM recommendations by party

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
D. D'Ascendis (AltaLink/EPCOR)[122]	2.88	7.64	0.61	0.50	8.38 (Canadian utility group)
	4.03	7.80	0.79	0.50	10.88 (U.S. electric utility group)
	4.03	7.80	0.76	0.50	10.70 (U.S. gas utility group)
Dr. Villadsen (ATCO/Apex/Fortis)[123]	3.85	5.91-6.56	37% Raw: 0.6-1.72 37% Blume: 0.51-1.54	-	9.81-11.76 (full comparator group)

122 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 86, 177-179. ROE results represent an average of CAPM and ECAPM models.

123 Exhibit 27084-X0469.01 PDF pages 46-49; Exhibit 27084-X0460_C, BV-12(a) ROE Model - 40%; Exhibit 27084-X0461, BV-12(b) ROE Model - 37%; Exhibit 27084-X0689.01-C, ATCO/Apex/Fortis IR responses to the AUC, PDF pages 1-4. If deemed equity is set at 40%, Dr. Villadsen calculated betas ranging from 0.56 to 1.61.

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
			37% Hamada: 1.01-1.21		
Concentric (ENMAX)[124]	3.73	7.59	0.83-0.86	0.50	10.73 (full comparator group)
Dr. Cleary (UCA)[125]	2.85	5.00	0.45	0.50	5.7 (Canadian comparator group)
D. Madsen (IPCAA)[126]	2.95	6.08	0.669	0.50	7.51 (Canadian and U.S. electric utility group)

123. The Commission did not consider the empirical CAPM (ECAPM) approach to estimate the notional ROE or ERP, consistent with the Commission's previous approach.[127] The Commission accepts Dr. Cleary's concerns with the ECAPM[128] methodology, and that the assumptions and variables used in the approach were not subject to adequate testing in this proceeding.

6.4.1.2 CAPM inputs

Risk-free rate

124. In considering the parties' CAPM ROE results, the Commission took into account the extent to which parties' estimate of the risk-free rate differed from the 3.10 per cent rate that the Commission found reasonable in Section 6.3.

Beta

125. Beta captures the sensitivity of a stock's returns to the market's returns. It is a measure of systematic risk – general risk that cannot be diversified away. In effect, beta measures the contribution made by an individual stock to the risk of the diversified market portfolio.

126. Considerable academic and empirical evidence has been filed on the record of this proceeding to support the position taken by parties on how beta should be calculated. In general, witnesses for the utilities used betas that:

- were sourced from established fee-for-service data providers widely used by the investment community, in particular Value Line and Bloomberg;

- were based on weekly data on the premise that more frequent observations better capture the contribution made by each individual stock in the comparator group of equities to the

124 Exhibit 27084-X0315, Concentric evidence, PDF pages 62, 64-65, 105. The betas used in Concentric's CAPM analyses for the entire comparator group are drawn from two sources: Value Line and Bloomberg. The MERP value of 7.59 represents an average of Canadian and U.S., historical and forward-looking values.

125 Exhibit 27084-X0320.02, Cleary evidence, PDF page 61. Beta of 0.45% is raw/unadjusted. ROE of 5.7% includes an A-rated Canadian utility bond yield spread adjustment of 0.095%.

126 Exhibit 27084-X0292, Madsen evidence, PDF pages 28-29.

127 Decision 20622-D01-2016, paragraph 199.

128 Exhibit 27084-X0759, Cleary evidence, PDF page 43-45.

risk of the diversified market portfolio over the measurement period. Selected measurement periods ranged from two[129] to five-years;[130]

- incorporated the Blume adjustment on the basis that it addresses the tendency of raw betas to change gradually over time, transforms historical unadjusted or raw betas into an expectational value consistent with the forward-looking nature of the cost of capital, and partially corrects for the known deficiencies of the CAPM;[131] and

- in the case of the evidence filed by Dr. Villadsen, used the Hamada adjustment to reflect a 40 per cent deemed equity component to standardize the capital structure of the comparable group of utilities and calculate beta[132] on an equivalent basis, given the relationship between financial leverage and equity returns.

127. For the consumer groups, Dr. Cleary and D. Madsen used a different approach to calculate beta:

- Dr. Cleary used weekly and monthly raw (unadjusted) betas for both the U.S. and Canadian comparators data from Bloomberg to arrive at an estimated beta of 0.45. Dr. Cleary did not support the use of either the Blume or Hamada adjustments to calculate beta.[133]

- D. Madsen used raw and adjusted betas in his analysis. He included Blume adjusted monthly betas on the basis that they are consistent with the forward-looking nature of a cost-of-capital determination. D. Madsen used five-year monthly data provided by YCharts and Yahoo Finance to determine an average adjusted beta of 0.669 for the combined Canadian and U.S. Electric Utility segments of the comparable group of utilities.[134] D. Madsen considered and then rejected the use of Blume adjusted, weekly Value Line betas.

128. In this proceeding, parties had much the same debates about beta as in past GCOC proceedings. Consistent with its views in past GCOC decisions, the Commission considers that there exists some room for legitimate differences of opinion among industry practitioners and academic experts on what constitutes a reasonable range for regulated utility betas.

129. For example, the Commission remains uncertain of the extent, if any, to which the Blume adjustment is warranted in determining betas for regulated utilities that face less risk than an average firm in the market. Indeed, there are ample reasons to question on what basis the

129 Transcript, Volume 5, page 973, lines 8-11 and 15, D'Ascendis evidence. D. D'Ascendis uses Bloomberg's default setting of two years to calculate beta.
130 Exhibit 27084-X0315, Concentric evidence, PDF page 62. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Concentric has computed Bloomberg betas using five years of weekly stock returns and using the S&P or the S&P/TSX Composite as the market index, in the case of U.S. or Canadian comparable equities, respectively.
131 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 76-84; Exhibit 27084-X0315, Concentric evidence, PDF pages 62-64; Exhibit 27084-X0047, Villadsen evidence, PDF pages 7-8; and Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44.
132 Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44. Dr. Villadsen used weekly data from Bloomberg over a three-year measurement period. A similar analysis was performed assuming deemed equity of 37%.
133 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 49-60 and Exhibit 27084-X0333, Cleary evidence.
134 Exhibit 27084-X0292, Madsen evidence, PDF pages 16-22.

systematic risks faced by regulated utilities might ever be expected to approach, much less exceed, those for the market as a whole, which is a central premise of the Blume adjustment.[135] Nevertheless, the Commission acknowledges that adjusted betas are widely used by finance professionals, as they provide useful information in certain circumstances.

130. As expressed in several past decisions, the Commission remains unpersuaded that adjusted betas are superior to raw betas in the context of regulated utilities. Rather, it finds that both raw and adjusted betas can provide useful information with respect to utility risk.[136] Similarly, the Commission continues to find that reliance on both weekly and monthly estimates of beta is reasonable.[137]

131. J. Coyne estimated beta to be 0.83 to 0.86,[138] while Dr. Villadsen calculated raw, Blume and Hamada adjusted betas, producing betas ranging from 0.51 to 1.72. Within this range Dr. Villadsen recommended for the Commission's approval a range of Hamada betas from 1.01 to 1.21.[139] The Commission finds these are unreasonably high given its findings regarding the overall risk of the Alberta utilities. More generally, the Commission does not accept that betas are understated for the utilities in the absence of the Hamada adjustment.

132. The Commission concludes that utility stocks are appreciably less risky and volatile than equities in the broader market, and therefore considers a reasonable range of betas for regulated gas and electric utilities to be between 0.45 (representing Dr. Cleary's unadjusted long-term beta) and 0.75 (in the range of adjusted betas recommended by D. Madsen[140] and D. D'Ascendis[141]). The high end of Dr. Villadsen's[142] beta estimates were well above this range.

Market equity risk premium

133. Parties to the proceeding used a variety of approaches to quantify the MERP.

134. D. Madsen's MERP of 6.08 per cent is an average of three MERP estimates: the implied MERP provided by Kroll of 6.0 per cent, Dr. Damodaran's implied MERP of 6.0 per cent as of January 1, 2023, and the implied MERP calculated by D. Madsen of 6.23 per cent by applying a Gordon Growth Model to the S&P500.[143]

135. Dr. Cleary adopted a MERP of 5.0 per cent, equal to the average of a commonly used historical range of 4 to 6 per cent. Dr. Cleary relied on a series of surveys and reports from academics, investment management firms, and actuarial service providers to establish historical and forecast returns for the Canadian, U.S. and world developed markets.[144]

136. Dr. Villadsen used the historical average premium of market returns over the long-term GoC bond yields, as per Duff & Phelps, for both Canada and the U.S. The MERP is expressed as

135 For a discussion of the history of Blume's adjustment and its limitations in the context of the regulated utility industry, see paragraph 164 of Decision 20622-D01-2016.
136 Decision 22570-D01-2018, paragraphs 345-346.
137 Decision 22570-D01-2018, PDF page 80, paragraph 344.
138 Exhibit 27084-X0315, Concentric evidence, PDF page 62.
139 Exhibit 27084-X0469.01, Villadsen evidence at PDF pages 46-48.
140 Exhibit 27084-X0292, Madsen evidence, PDF page 29.
141 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 80.
142 Exhibit 27084-X0469.01, PDF pages 46-49.
143 Exhibit 27084-X0292, Madsen evidence, PDF pages 24-29.
144 Exhibit 27094-X0320.02, Cleary evidence, PDF pages 39-49.

the arithmetic average and is 5.91 per cent for Canada (1935-2021) and 7.46 per cent for the U.S. (1926-2021). By adjusting Bloomberg forecast MERP for the spread between a 10-year and 30-year government bond yield, Dr. Villadsen also calculated a forecast MERP for Canada of 6.56 per cent and a lower number for the U.S. using proprietary data.[145]

137. D. D'Ascendis calculated a prospective MERP for both Canada and the U.S. by applying a constant growth DCF model to the companies comprising each of the S&P/TSX and S&P 500. The resulting total return for each index was then reduced by the forecast Canadian or U.S. long-term government bond yield. This produced forecast MERPs for Canada and the U.S. of 9.92 per cent and 7.03 per cent, respectively. D. D'Ascendis also estimated historical MERPs by using a regression analysis in which the MERP is expressed as a function of the long-term government bond yield. The historical MERPs for Canada and the U.S. using this approach were 5.35 per cent and 8.57 per cent, respectively.[146] The Commission notes that overall, D. D'Ascendis recommended MERPs of 7.64 for Canada and 7.80 for the U.S. as summarized in Table 3 above.

138. Concentric used the MERP ex-post historical arithmetic average based on data from Kroll of 5.74 per cent for Canada (1919-2021), and 7.46 per cent for the U.S. (1926-2021). Concentric, used an approach similar to that of D. D'Ascendis, to forecast MERPs of 9.22 per cent for Canada and 7.93 per cent for the U.S.[147] Concentric's recommended MERP, as set out in Table 3, is 7.59.

139. Parties developed their MERP recommendations using three general approaches or a combination of them. The first approach was to examine historical MERPs; that is, the difference between historical long-term realized stock market returns and the risk-free rate (as measured by long-term GoC bond yields) in Canada and the U.S. The Commission agrees that this approach is informative as it captures a large number of economic and monetary cycles and minimizes the risk that calculated MERPs reflect anomalous or transitory market conditions. The historical MERP values were approximately 6.0 per cent for Canada and 7.50 per cent for the U.S.

140. The second approach was to estimate prospective or forward-looking MERPs by relying on available market return estimates of investment management professionals and actuarial service providers, as was done by Dr. Cleary to arrive at a 4 to 6 per cent estimate and by Dr. Villadsen to arrive at a 5.91 to 6.56 per cent recommended MERP estimate.

141. The Commission recognizes that there may be pitfalls to relying on available forecasts of market return. For example, these estimates may not be as robust as empirical studies, or be amenable to ready analysis or testing, and may be prepared for different purposes; however, this type of evidence does offer some indication of what market professionals believe the ROE may be in the future. This can, and potentially does, affect investor expectations and subsequent behaviour. That, in itself, can shed light on the limits or frontiers of the range of reasonable estimates of the required ROE.

142. Under the third approach, parties estimated prospective MERPs by calculating expected market return. To do so, Concentric and D. D'Ascendis employed forecast earnings growth rates in excess of 9 per cent, which resulted in estimates for expected market returns ranging from

[145] Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 42-43. Exhibit 27084-X0458-C, Appendix BV-7 Bond Yields & MERP, tab "MRP calculation."
[146] Exhibit 27084-X0390, D'Ascendis evidence, PDF page 85.
[147] Exhibit 27084-X0315, Concentric evidence, PDF pages 64-65.

10.4 per cent to 12.8 per cent for Canada and from 11.0 per cent to 11.8 per cent for the U.S. This, in turn, produced MERP estimates in the order of 9 to 10 per cent. Consistent with the findings in the 2018 GCOC decision, the Commission considers these estimates excessive, as they are based on calculated expected market returns that reflect unrealistically high earnings growth assumptions.

143. Given the above observations, the Commission notes that when the MERP estimates in the order of 9 per cent calculated by Concentric and D. D'Ascendis are excluded, the remaining MERP recommendations of the parties fall into what the Commission considers is a reasonable range of 5.9 per cent to 7.5 per cent.

Flotation allowance

144. In past GCOC proceedings, the Commission has accepted a flotation allowance of 0.50 per cent in estimates of ROE obtained from the application of the various models, including CAPM. The flotation allowance is normally included in the approved return to account for administrative costs and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.[148] No party opposed the use of 0.50 per cent for the flotation allowance. The Commission finds this flotation allowance continues to be reasonable for use in the financial models.

6.4.2 Constant growth DCF model

145. The constant growth DCF model assumes that the market price of a stock is equal to the present value of the cash flows that the owners of the shares expect to receive. In general, expected future cash flows are represented by the dividends paid per share. This pricing relationship is generally expressed as:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty}$$

where:

P_0 represents the current stock price;

D_1 … D_∞ represent expected future dividends; and

k (or K) is the discount rate or required ROE.[149]

146. Each of the variables in the DCF approach must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The constant growth DCF recommendations by parties are summarized in Table 4.

[148] Decision 22570-D01-2018, PDF page 104.
[149] The expression can be simplified and rearranged into annual and quarterly compounding DCF equations: Exhibit 27084-X0292, Madsen evidence, PDF page 29.

Table 4. Constant growth DCF recommendation by party

Witness (sponsoring party)	ROE	Flotation allowance[150]	ROE including flotation allowance
	(%)		
D. D'Ascendis (AltaLink/EPCOR)[151]	10.21 (Canadian utilities) 9.34 (U.S. electric utilities) 10.01 (U.S. natural gas utilities)	0.50	10.71 (Canadian utilities) 9.84 (U.S. electric utilities) 10.51 (U.S. natural gas utilities)
Dr. Villadsen (ATCO/Apex/Fortis)[152]	12.79 (Canadian utilities) 9.38 (U.S. electric utilities) 9.66% (U.S. gas utilities)	0.50	13.29 (Canadian utilities) 9.88 (U.S. electric utilities) 10.16 (U.S. gas utilities)
Concentric (ENMAX)[153]	9.88 (Canadian proxy group) 9.43 (U.S. electric proxy group) 9.84 (U.S. gas proxy group) 9.59 (N.A. combined proxy group)	0.50	10.38 (Canadian proxy group) 9.93 (U.S. electric proxy group) 10.34 (U.S. gas proxy group) 10.09 (N.A. combined proxy group)
Dr. Cleary (UCA)[154]	6.35	0.50	6.85
D. Madsen (IPCAA)[155]	7.31-9.14	0.50	7.81-9.64

6.4.2.1 Constant growth DCF inputs

Current stock price

147. To estimate the current stock price input to the DCF model, most parties calculated the average closing price over a period ranging from 15 to 90 trading days ending between late December 2022 and late January 2023 to avoid biases that may arise over very short periods of time from anomalous or transitory events.[156]

148. The Commission accepts the use of an averaging period to calculate the current stock price to mitigate the risk that a single date, point-in-time estimate may be biased by market conditions on the pricing date. The averaging period should not exceed 90 days, as a longer averaging period would likely violate the empirical assumption that the constant growth DCF approach uses current stock prices. In addition, the Commission will accept the adjustment of the current quarterly dividend by the chosen dividend growth rate, as submitted by D. D'Ascendis, Dr. Villadsen and Concentric. No party provided a contrary view that the adjustment was inappropriate.[157]

150 The constant growth DCF directly calculates ROE prior to the addition of the flotation allowance.
151 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 47. Average of the mean and median.
152 Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 54-55. Exhibit 27084-X0460-C, BV-12a, Villadsen evidence. ROE values are presented at 40% equity thickness.
153 Exhibit 27084-X0315, Concentric evidence, PDF pages 53-57. Exhibit 27084-X0490, Concentric evidence, sheet JMC-3 Constant DCF. ROE results represent mean values. Of note, Concentric's recommended ROE of 9.50% is based on the average of the multi-stage DCF model (not the constant growth DCF model).
154 Exhibit 27084-X0320.02, Cleary evidence, PDF page 71. Dr. Cleary used only the Canadian utilities in his recommendations.
155 Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Attachment 1, Madsen evidence, Tab "DCF." D. Madsen does not use the U.S. Gas utility comparable equities in his constant growth analysis and excludes Algonquin Power & Utilities Corp. from his DCF calculations.
156 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 42; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1, Exhibit 27084-X0292, Madsen evidence, PDF page 32.
157 The Commission notes that the constant growth DCF formula set out at the beginning of the section is taken from D. Madsen's evidence and clearly shows the adjustment of the dividend by the growth rate (footnote 55).

Dividend

149. The experts adopted slightly different approaches to how they calculated dividends. Most took the annualized dividend at year-end 2022 for each utility and then increased it quarterly or semi-annually by a fixed percentage of the forecast growth rate.[158] Dr. Cleary's approach was to provide a number of dividend yield calculations, including trailing 12-month dividend yields from December 2022 and average five-year and seven-year dividend yield averages.[159]

Dividend growth rate

150. Several of the experts relied on analysts' forecasts of company-specific dividend and earnings per share (EPS) growth rates.[160] D. Madsen also considered data from other sources and both he and Dr. Cleary[161] considered historical data. There was debate on whether dividend growth rates in the constant growth DCF analysis can the exceed the growth rate of the overall economy, as measured by the GDP growth rate. For example, D. Madsen said that, generally, dividend growth estimates should be below forecast growth in nominal GDP, while D. D'Ascendis did not agree with such limitation.

151. In past GCOC decisions the Commission rejected the use of dividend growth rates that exceeded estimates of the nominal long-term GDP growth rate. In this proceeding, Concentric filed evidence that earnings and dividend growth have exceeded GDP between 2007 and 2021 in support of the proposition that analyst estimates of growth rates above GDP are reasonable.[162] D. D'Ascendis indicated that the compound annual utility industry EPS growth rate of 6.53 per cent exceeded the U.S. GDP growth rate over the 1947 to 2021 period.[163] While this supports the view that utility EPS growth can exceed nominal GDP growth, the Commission notes that D. Madsen provided evidence of the recent historical EPS growth rates of the Alberta utilities and concluded that average growth was generally lower than his forecast nominal GDP.[164] Further, he noted that the Alberta utilities have a "natural barrier to growth" due to their inability to expand into other jurisdictions.[165] On this point, the Commission notes that growth in dividends can come from higher earnings, and not only from the expansion of company operations.

152. Nevertheless, as in past decisions, the Commission remains concerned with the aggressive dividend growth rates and forecasts relied on by some experts for the utilities, both for utilities as a sector of the economy, and the economy as a whole. It notes Dr. Cleary's observation regarding high growth estimates put forward by experts for the utilities and for the economy as a whole:

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[158] Exhibit 27084-X0390, D'Ascendis evidence, PDF page 41; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0292, Madsen evidence, PDF page 32; Exhibit 27084-X0304, Madsen evidence, Sheet DCF.

[159] Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1.

[160] Exhibit 27084-X0391, D'Ascendis evidence, Sheets 2.2-2.4 CGDCF. EPS estimates were from Value Line, Zack's, and Yahoo! Finance; Exhibit 27084-X0469.01, Villadsen evidence, PDF page 51; Exhibit 27084-X0315, Concentric evidence, PDF page 54.

[161] Exhibit 27084-X0320.02, Cleary evidence, PDF pages 64-65.

[162] Exhibit 27084-X0315, Appendix 1, Evidence of Concentric Energy Advisors, PDF pages 56-57.

[163] Exhibit 27084-X0390, D'Ascendis evidence, PDF page 159, Schedule 3, and Exhibit 27084-X0665.

[164] Exhibit 27084-X0292, Madsen evidence, PDF page 38.

[165] Exhibit 27084-X0292, Madsen evidence, PDF page 38.

> The contradiction in these assumptions is obvious – i.e. if the economic environments are expected to experience high-risk and slow growth conditions, how is it reasonable to assume that corporate earnings and dividends (for the entire stock market of all publicly listed companies) can be expected to grow indefinitely at these abnormally high rates?[166]

153. In the 2018 GCOC decision, with reference to Dr. Cleary's evidence, the Commission recognized that the utilities are essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable.[167] Indeed, D. Madsen quoted in his evidence from a publication by Dr. Damodaran, who opined that it is questionable whether any firm is able to sustain high growth in the long term as it will eventually stop growing either due to limitations on size or to the effects of competition.[168]

154. On the other hand, the sustainable growth rate Dr. Cleary used to estimate expected dividend growth rates relied on historical seven-year average dividend yields and payout ratios and used accounting data, rather than readily available, market-driven forecasts. The Commission notes that this approach produces growth estimates that are less than actual historical rates of dividend growth[169] and less than inflation, resulting in negative real growth. As a result, the Commission is concerned that Dr. Cleary's sustainable growth rate produces results that understate dividend growth.

155. The Commission will generally continue to consider forecast long-term nominal GDP growth as a proxy for forecast dividend growth. Growth of the utilities will fluctuate over the years but, overall, considering the business profile of the utilities, the Commission does not expect the utilities will consistently achieve growth in dividends greater than the nominal GDP growth rate.

156. In this regard, the Commission finds it reasonable to use in the constant growth DCF model the minimum and mean analyst growth rates submitted in this proceeding; however, maximum EPS growth rates appear to be unreasonably high. Despite its general criticism of using high dividend growth rates, the Commission notes that analyst EPS growth estimates are widely used by the investment community, and concerns relating to analyst EPS optimism bias for large capitalization stocks like those in the comparator group may be overstated, at least relative to estimates for small to mid-cap stocks of which there are not many in the comparator group, in any event.[170] The use of analyst EPS estimates supplied by established data service providers, such as Value Line, Zack's, Yahoo! Finance, SNL Financial, and Thomson First Call minimizes the opportunity for arbitrary adjustments and custom calculations for which there is no broad support among parties to the proceeding.

6.4.3 Multi-stage DCF model

157. The multi-stage DCF model reflects the premise that investors value an investment according to the present value of its expected cash flows over time.[171] It is an extension of the constant growth DCF model, but the multi-stage DCF approach does not assume a single,

166 Exhibit 27084-X0759, Dr. Cleary rebuttal evidence (redacted), PDF page 3.
167 Decision 22570-D01-2018, paragraph 438.
168 Exhibit 27084-X0292, D. Madsen evidence, PDF pages 34-35.
169 Exhibit 27084-X0304, Madsen evidence, Tab DCF, column "Growth forecast past 5 years (per annum)."
170 Transcript, Volume 3, pages 704-722.
171 Exhibit 27084-X0390, Concentric evidence, PDF page 53.

constant estimate of dividend growth in perpetuity.[172] In general, the multi-stage DCF assumes that dividends grow at a constant rate over a short-term period, usually five years in length, transition to an assumed long-term constant growth rate over an interim period, also usually five years in length, and then grow in perpetuity at a growth rate usually equal to forecast nominal GDP.

158. The multi-stage DCF recommendations of parties are summarized in the following table.

Table 5. Multi-stage DCF recommendations of parties

Witness (sponsoring party)	ROE	Flotation allowance	ROE including flotation allowance
		(%)	
D. D'Ascendis (AltaLink/EPCOR)[173]	10.34 (Canadian utilities) 9.21 (U.S. electric utilities) 9.39 (U.S. natural gas)	0.50	10.84 (Canadian utilities) 9.71 (U.S. electric utilities) 9.89 (U.S. natural gas)
Dr. Villadsen ATCO/Apex/Fortis)[174]	11.81 (Canadian utilities) 7.88 (U.S. electric utilities) 7.62 (U.S. gas utilities)	0.50	12.31 (Canadian utilities) 8.38 (U.S. electric utilities) 8.12 (U.S. gas utilities)
Concentric (ENMAX)[175]	9.42 (Canadian proxy group) 8.28 (U.S. electric proxy group) 8.65 (U.S. Gas proxy group) 8.49 (N.A. combined proxy group)	0.50	9.92 (Canadian proxy group) 8.78 (U.S. electric proxy group) 9.15 (U.S. gas proxy group) 8.99 (N.A. combined proxy group)
Dr. Cleary (UCA)[176]	7.01	0.50	7.51
D. Madsen (IPCAA)[177]	7.38-8.46	0.50	7.88-8.96

6.4.3.1 Multi-stage DCF inputs

159. The variables that must be estimated in a multi-stage DCF equation are the same as those set out in Section 6.4.2, except the assumed short-term and long-term dividend growth rates and the length of the short-term and transition periods are expressed in years.

Dividend growth rate

160. Most of the experts calculated the multi-stage DCF in a similar manner, and many of the variables are calculated in the same way as for the constant growth DCF calculations, other than the dividend growth rate. As was the case for the constant growth DCF model, parties took different approaches to forecasting the growth rate.[178] In forecasting nominal GDP growth rates, parties used either the Canadian forecast, or a combination of the Canadian and U.S. forecast.

172 Exhibit 27084-X0390, Concentric evidence, PDF page 53.
173 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 50. Recommended M-DCF reflects average of mean and median results.
174 Exhibit 27084-X0469.02, Villadsen evidence, PDF pages 54-55. ROE values are presented at 40% equity thickness.
175 Exhibit 27084-X0315, Concentric evidence, PDF page 59. Exhibit 27084-X0490, tab "JMC-4 Multi-Stage DCF."
176 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 70-71.
177 Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Madsen evidence, Sheet DCF.
178 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 47-48. Exhibit 27084-X0391, D'Ascendis evidence, sheets 2.5-2.8, Exhibit 27084-X0469, Villadsen evidence, PDF pages 49-57. Exhibit 27084-X0471, Villadsen evidence, PDF pages 10-13, Exhibit 27084-X0315, Concentric evidence, PDF pages 57-58. Exhibit 27084-X0490, Sheet JMC-4 Multi-Stage DCF.

161. D. Madsen also calculated the multi-stage DCF using the approach used by the U.S. Federal Energy Regulatory Commission (FERC), applying it to several scenarios.[179] Using the FERC approach led to similar growth rates. Dr. Cleary took a slightly different approach and used a variation of the constant growth DCF called the H-Model. The approach assumes that growth in dividends moves in a linear manner from a short-term growth rate toward a long-term growth rate over a specified period of time, defined as the “half life.”

162. D. Madsen’s multi-stage DCF calculations included using current and one-year forecast EPS growth rates as a proxy for a five-year forecast EPS growth rate or a one-year EPS growth estimate in year one and the five-year EPS estimate in years two to five.[180] D. Madsen also used the FERC two-step DCF approach. He made adjustments to the FERC approach, including the weights used for short- and long-term growth, and used a simple average of the short-term and long-term growth estimates to adjust the dividend. These adjustments were criticized by Dr. Villadsen and D. D’Ascendis.[181]

163. The multi-stage DCF approach used by Dr. Villadsen[182] models the first five years of dividends at a growth rate specific to the company she is estimating, then tapered the growth down towards that of the economy over the next five years. For year 10 onwards, Dr. Villadsen used the GDP growth rate as the perpetual growth rate for dividends.

164. Regarding the results of Dr. Cleary’s H-Model DCF approach, the Commission is persuaded by the concerns expressed by experts for the utilities who raised a number of empirical and qualitative issues with Dr. Cleary’s approach. These included the use of sustainable growth rates that are less than forecast inflation,[183] resulting in negative real utility growth, sustainable growth rates that are less than historical actuals,[184] and the need to consider growth arising from both internally generated funds and from issuances of equity.[185]

6.4.4 Other risk premium models

165. In addition to relying on CAPM and DCF models, some parties used the following risk premium models to help inform their fair ROE estimates: (i) Concentric and Dr. Villadsen used the government bond yield risk premium model; (ii) Dr. Cleary and D. D’Ascendis relied on the utility bond risk yield premium model; and (iii) D. D’Ascendis used the predictive risk premium model. The Commission determines that it will not rely on any of these models for the purposes of the present decision.

179 Exhibit 27084-X0292, Madsen evidence, PDF pages 42-44. Exhibit 27084-X0304, Madsen evidence.
180 Exhibit 27084-X0304, Madsen evidence, Sheets DCF and Multi DCF Alt. FERC Scenario 1: nominal estimated GDP of 3.77% is used for both the short-term and long-term growth rate; FERC Scenario 2: short-term growth rate is the average of the current year forecast and next year’s growth rate and nominal estimated GDP of 3.77% is used as the long-term growth rate; FERC Scenario 3: short-term growth rate is equal to analyst five-year EPS growth rates and nominal estimated GDP of 3.77% is used as the long-term growth rate; and FERC Scenario 4: the average the short-term growth rate in scenarios 1 to 3 is used as the short-term growth rate and the long-term growth rate is nominal estimated GDP of 3.77%.
181 Exhibit 27084-X0761, Villadsen evidence, PDF pages 26-27, Exhibit 27084-X0750, D’Ascendis evidence, PDF pages 32-36.
182 Exhibit 27084-X0471, Villadsen evidence, PDF pages 9-10.
183 Exhibit 27084-X0750, D’Ascendis evidence, PDF page 29.
184 Exhibit 27084-X0743, Concentric evidence, PDF page 41.
185 Exhibit 27084-X0761.02, Villadsen evidence, PDF page 61.

166. The government bond risk premium approach estimates the ROE as the sum of the ERP and the yield on the 30-year U.S. Treasury bond. The ERP was calculated as the difference between authorized returns from U.S. electric and gas utilities and the then-prevailing quarterly 30-year U.S. Treasury yield. Consistent with prior GCOC decisions,[186] the Commission continues to be of the view that the approved ROEs from other jurisdictions are not, strictly speaking, wholly market-based data and therefore, will not place any weight on the results of the government bond risk premium model.

167. Under the utility bond risk premium approach, a required ROE is calculated by adding an equity premium to a utility bond yield. In past GCOC decisions, the Commission accepted the bond yield and utility bond yield approaches to be valid tools in estimating the cost of equity, as they are simple to use and conform to the basic principle that investors require a higher return for assets with greater risk. Although the Commission still considers the empirical basis of the utility bond yield methodology to be valid, for the purposes of this decision the Commission will not rely on the utility bond yield risk premium approaches used by Dr. Cleary and D. D'Ascendis.

168. Dr. Cleary's recommended risk premium of 2.50 per cent is subjective, not supported by any analysis and does not take into the account the changing market environment. D. D'Ascendis's risk premiums are estimated in a more rigorous manner; however, they have issues of their own. For one of his models, D. D'Ascendis used the authorized ROEs from litigated cases in other jurisdictions to estimate the utility bond ERP.[187] As stated earlier, the Commission prefers not to use authorized ROEs as a proxy for market data. For the other two models, D. D'Ascendis relied on market data; however, they require the Commission's determinations on a number of new variables such as the expected utility bond yields and expected returns for an index of U.S. utilities.[188] Variables and calculations in D. D'Ascendis's bond yield risk premium models were not explored in depth in this proceeding, and in the Commission's view, the merits of the utility bond risk premium approach do not outweigh the additional burden and empirical difficulties associated with measuring the ERP to utility bond yield, given the presence of the more widely accepted CAPM and DCF models.

169. Finally, the predictive risk premium model is based on the ARCH/GARCH[189] models that use historical volatility to predict future volatility, which can then be translated to a predicted ERP. The predictive risk premium model estimates the ERP directly, by predicting volatility or risk.[190] In the Commission's view, this analysis is similar in concept to the technical analysis of market data that relies only on historical time series data for a single indicator, for example, returns on a stock, to predict future returns for this stock. The Commission is not persuaded that this approach is superior to the CAPM and DCF models that use a variety of inputs to estimate the ERP and/or required return, especially as the predictive risk premium model approach is not used widely, if at all, by other regulators.

186 Decision 22570-D01-2018, PDF pages 88-91.
187 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 64.
188 In Exhibit 27084-X0390, PDF page 63, D'Ascendis explained, "As done for the S&P TSX Composite and the S&P 500, using dividend and EPS growth rate data from Bloomberg, I calculated projected total returns of the S&P/TSX Capped Utilities."
189 The Autoregressive Conditional Heteroskedasticity (ARCH) and Generalized Autoregressive Conditional Heteroskedasticity (GARCH) models are based on the premise that the volatility of prices and returns clusters over time and is therefore highly predictable.
190 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 54-60.

6.4.5 Notional ROE and base forecast ERP

170. In this proceeding, the Commission was presented with a wide range of notional ROE and base ERP recommendations that were based on a variety of approaches, models and directional indices. The Commission rejected many of these approaches and instead focused on the results of the well-known and widely used models (CAPM, constant growth DCF, and multi-stage DCF) in GCOC proceedings. The Commission determines the notional ROE to be 9.00 per cent and the base forecast ERP to be 5.90 per cent.

171. Table 6 illustrates the ranges of notional ROE (including 0.50 flotation allowance) based on the results of the financial models submitted by the parties and reflects the resulting ERPs after subtracting the Commission's 3.10 per cent risk-free rate.

Table 6. Notional ROE and base forecast ERP from financial models

Financial model	ROE (%) range		Base forecast ERPs (%) range including flotation allowance (ROE less 3.10% risk-free rate)	
	Low	High	Low	High
CAPM	5.7	11.76	2.6	8.66
Constant growth DCF	6.85	13.29	3.75	10.19
Multi-stage DCF	7.51	12.31	4.41	9.21

172. It is obvious from the table above that the Commission was presented with a wide range of results from the experts using the CAPM, constant growth DCF, and multi-stage DCF models. The model results are subject to a high degree of variability given the range of data sources, forecasts and assumptions that parties choose to use, and the judgment and experience of the expert doing the modelling. These models provide some guidance to the Commission, but, as evidenced by the wide range of results, they do not produce a single correct number for the fair return that the Commission should choose.

173. In assessing the results of the models, the Commission is mindful of its concerns expressed in sections 6.4.1 to 6.4.3, including:

- CAPM results using a forecast risk-free rate that differs significantly from the 3.10 per cent rate the Commission found reasonable in Section 6.3.
- CAPM results using betas that were close to or exceeded one.
- CAPM results using MERPs based on excessively high earnings growth rates in estimating market return.
- Constant growth DCF results using dividend growth rates that are too high (e.g., exceed long-term nominal GDP growth) or too low (e.g., near or less than inflation).

174. The Commission has set the base forecast ERP and resulting notional ROE towards the lower end of the ROE ranges calculated in the financial models given its finding that the risk profile of the Alberta utilities is at the low end of the comparator group of companies.

175. D. D'Ascendis calculated a low CAPM ROE of 8.38 per cent, a constant growth DCF ROE of 9.84 to 10.71 per cent and a multi-stage DCF ROE of 9.71 to 10.84 per cent. Some of D. D'Ascendis's DCF ROE estimates are based on excessively high earnings growth rates, which

the Commission rejects. The notional ROE of 9.00 per cent is closer to the lower end of D. D'Ascendis's three calculations, namely the low 8.38 per cent CAPM ROE.

176. The low end of Dr. Villadsen's calculated ROEs was the 8.12 per cent for the multi-stage DCF. Dr. Villadsen's CAPM ROE of 9.81 to 11.76 per cent uses a high beta and high risk-free rate. Concentric's CAPM ROE of 10.73 uses a lower beta and risk-free rate than Dr. Villadsen; however, Concentric's risk-free rate is 3.73 per cent. The low end of Concentric's calculated ROEs is 8.78 per cent for the multi-stage DCF. Dr. Villadsen and Concentric's constant growth DCF ROEs range from 9.88 to 13.29 per cent, and 9.93 to 10.38 per cent, respectively. Some of Concentric's constant growth DCF estimates are based on excessively high earnings growth rates, which the Commission rejects.

177. The high end of Dr. Cleary's three ROE calculations was 7.51 per cent for the multi-stage DCF but even that high-end estimate is too low. It is approximately 100 basis points lower than the current approved ROE, and the Commission finds no compelling reason to decrease the currently approved ROE. D. Madsen calculated a CAPM ROE of 7.51 per cent, a constant growth DCF ROE range of 7.81 per cent to 9.64 per cent, and a multi-stage DCF ROE range of 7.88 per cent to 8.96 per cent. Given the Commission's finding that there is no compelling reason to decrease the currently approved ROE, the Commission considers the higher end of D. Madsen's constant growth DCF and multi-stage DCF ROEs to be more helpful. D. Madsen uses long-term nominal GDP growth rates in his DCF models. The notional ROE of 9.00 per cent is lower than D. Madsen's 9.64 per cent constant growth DCF ROE, and slightly higher than D. Madsen's 8.96 per cent multi-stage DCF ROE.

178. In addition to the various factors outlined above, the Commission's reasoning in setting the base forecast ROE and notional ROE on the lower end of the ROE ranges developed by parties in this proceeding includes the considerations set out below.

179. A great deal of evidence (and supporting argument) was filed in this proceeding by the utilities in an effort to persuade the Commission that the macroeconomic changes (and related systematic risks) confronting them compared to what they faced in 2018, together with other business, market, regulatory, competitive and related operating risks they deal with on a daily basis, warrant a significant increase in both their approved ROEs and deemed equity ratios commencing in 2024. After considering the full record of this proceeding, the Commission finds that, on balance, there are reasonable grounds for the notional ROE for Alberta utilities to be raised above the 8.5 per cent ROE approved for 2023, but not to set it as high as the utilities have been requesting.

180. Utilities are regulated monopolies. They supply essential, highly price-inelastic, services to captive customers, with few, if any, competitively available substitutes. Aside from fluctuations attributable to short-term extremes of weather, natural disasters, pandemics and the like, demand for their services is highly predictable from one season to the next, and one year to another.

181. In exchange for being cloaked with a legislative "duty to serve" or "supplier-of-last-resort" obligation as it is sometimes called, public utilities have long been the beneficiaries of a statutory guarantee, enforced by regulation and a century or more of appellate level jurisprudence, of a legal right to a reasonable opportunity to earn a fair return on their prudently invested capital. As leading credit rating agencies have noted on more than one occasion, utilities

under the Commission's jurisdiction face a favourable regulatory environment that excludes some or all of volumetric, counterparty and commodity price risks,[191] and allows for the flowthrough to customers of most, if not all, cost increases that are outside the utility's direct control.

182. Alberta utilities are also the beneficiaries of a concerted effort in recent years to eliminate regulatory lag and to reduce unnecessary regulatory burden, plus numerous incentives to cut costs and earn supra-normal returns (i.e., earnings in excess of their approved rate of return) between rate cases under cost-of-service (COS) regulation for transmission utilities or performance-based regulation (PBR) terms for distribution utilities.[192] Together, these conditions have the effect of significantly reducing the overall level of risk faced by Alberta utilities relative to the market as a whole. As noted in Section 4 above, while many competitive industries endured considerable economic and financial duress attributable to pandemic-related disruptions in the past few years, Alberta utilities appear not only to have avoided any lasting economic harm but have also exhibited, overall, very robust financial results throughout. Moreover, the fact that no evidence was presented by utilities attesting to undue hardship in raising new debt or equity capital on competitive terms at any time since the 2018 GCOC proceeding reinforces the overall conclusion that they operate in a lower risk and relatively more supportive regulatory environment than that of the comparator group.

6.5 Other variables of the formulaic approach

183. The approved notional ROE of 9.0 per cent will serve as a base ROE to which the approved formulaic approach will be applied each year:

$$ROE_t = 9.0\% + 0.5 \times (\mathrm{YLD}_t - 3.10\%) + 0.5 \times (\mathrm{SPRD}_t - \mathrm{SPRD}_{base})$$

184. This section explains how the Commission arrived at each remaining variable to be used in the approved formulaic approach. Specifically, Section 6.5.1 deals with the adjustment factors for changes in GoC bond yield and utility bond yield spread. Section 6.5.2 deals with the base and test year values for long GoC bond yields. Section 6.5.3 deals with the base and test year values for utility bond yield spreads.

6.5.1 Adjustment factors for changes in GoC bond yield and utility bond yield spread

185. In future test years, risk-free rates (approximated by long-term GoC bond yield) and utility bond yield spreads will continue to vary as financial and economic conditions evolve. The approved formulaic approach accounts for fluctuations in both of these factors relative to their base values approved in this decision.

186. The adjustment factor for the 30-year GoC bond yield (denoted as w_1 in the formula) expresses the relationship between changes in the forecast long GoC bond yield and the ROE for the test year. The adjustment factor for utility bond yield spread (denoted as w_2 in the formula) expresses the relationship between changes in the utility bond yield spread and the ROE for the test year. The theoretical basis behind these adjustment factors is that the ROE (and underlying

[191] Exhibit 27084-X0897, IPCAA-ATC-4, Extract from Proceeding 28174, Exhibit 28174-X0011, SP Rating Results for AltaLink, L.P., PDF pages 4 and 6.

[192] The Commission recognizes that utilities subject to COS regulation do not have the same incentives and returns as utilities subject to PBR. Notwithstanding that, the Commission observes that some Alberta utilities under COS regulation do achieve returns over approved ROE.

ERP) do not change one-for-one with the change in risk-free rate and bond yield spread; rather, they change to some lesser degree in response to fluctuations in those variables.

187. Ideally, the values for these adjustment factors should be determined through an empirical exercise based on the strength of the relationship between interest rates and ERPs observed by analysing historical data. To that effect, the Commission asked parties to comment on the extent of the relationship between changes in the forecast long GoC bond yield and the forecast ERP, and whether this relationship is sustainable and statistically significant with a high coefficient of determination.

188. In the Commission's view, the results of the statistical analyses presented in this proceeding were not conclusive. Although there were some statistical analyses showing that the 0.5 adjustment factors for both w_1 and w_2 were in the range of reasonableness,[193] with the exception of Concentric, parties did not rely heavily on their statistical analyses and, instead, appeared to defer to the OEB adjustment factors of 0.5 for both w_1 and w_2, the latter of which is also used by the California Public Utilities Commission (CPUC). This was the approach taken by Dr. Villadsen,[194] D. D'Ascendis[195] and D. Madsen.[196]

189. Concentric's regressions showed a statistically significant, sustained relationship between changes in risk-free rates and authorized ROEs as well as between changes in utility bond yield spreads and authorized ROEs.[197] Based on these regressions, Concentric recommended the 0.5 adjustment for both factors in the formula.[198] However, the Commission will not rely on this analysis given its determination, expressed throughout this decision, not to use authorized ROEs as a proxy for market data.

190. An alternative to the adjustment factors used by the OEB was presented by Dr. Cleary who recommended adjustment factors of 0.75 for both w_1 and w_2. The Commission is not persuaded that a 0.75 adjustment factor is warranted. Although of limited usefulness, the statistical analyses on the record of this proceeding (not including Concentric's) do provide general support for the 0.5 adjustment factors; at least more so than for the 0.75 adjustment factor. In addition, both the OEB and the EUB found that the 0.75 adjustment factor with respect to changes in GoC bond yield resulted in unduly heightened sensitivity to GoC bond yield, contributing to the demise of their formulas that were in place pre-2009.[199] The Commission agrees with the approach taken by the majority of parties that it is preferable to use the adjustment factors used by the OEB and CPUC whose formulas have been in place for a number of years.

[193] Exhibit 27084-X0900, Madsen undertaking No. 1. D'Ascendis: Exhibit 27084-X0399, Morin approach; Exhibit 27084-X0408, Harris approach; Exhibit 27084-X0411, Harris and Marston approach; Exhibit 27084-X0413, Brigham, Shome and Vinson approach; Exhibit 27084-X0440, Maddox, Pippert and Sullivan approach. Dr. Cleary: Exhibit 27084-X0605, UCA-AUC-2023FEB21-005, PDF pages 14-15.

[194] Exhibit 27084-X0469, Villadsen evidence, PDF page 79.

[195] Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 105, 112.

[196] Exhibit 27084-X0292, Madsen evidence, PDF page 50.

[197] Exhibit 27084-X0490, tabs "JMC-7.1 Risk Premium – Electric" and "JMC-7.2 Risk Premium – Gas."

[198] Exhibit 27084-X0315, Concentric evidence, PDF page 109. Exhibit 27084-X0743, Concentric reply evidence, PDF page 51.

[199] Exhibit 27084_X0678, EDTI-AML-CCA-2023FEB21-003 Attachment (OEB Report), PDF page 3.

191. The Commission approves a 0.5 adjustment factor for both changes in the 30-year GoC bond yield (w_1) and changes in the utility bond yield spread (w_2) in the formula.

6.5.2 Base and test year values for long-term GoC bond yield

192. As set out in Section 6.3, the risk-free rate of 3.10 per cent will serve as the base long-term GoC bond yield (YLD_{base}) in the formulaic approach. The updated risk-free rate forecast for each test year will be measured against this base value.

193. Regarding the 30-year GoC bond yield forecast for the prospective test year (YLD_t), parties recommended that methodologies be employed consistent with the methods they used to arrive at their respective base risk-free rate estimates (these methodologies are summarized in Table 1 from Section 6.3). Parties' choice of which forecast publication date to use was based on their assumptions as to when the Commission will calculate the ROE for the upcoming test year; on that basis parties presumed the Commission will rely on either September or October data.

194. The Commission agrees with parties that it is beneficial to maintain consistency in forecasting methods between base and test year values and therefore will use the same method for forecasting the risk-free rate. In Section 6.3, the Commission determined that it will base the calculations for a test year on the data from October of the preceding year. Consistent with these determinations, the Commission finds that forecast long-term GoC bond yield will be calculated as the weighted average of (i) the 30-year GoC bond yield forecasts published by RBC, TD and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (ii) the naïve forecast representing the average long-term GoC bond yield[200] over the period October 1 to October 31 each year preceding the test year (0.25 weight).

6.5.3 Base and test year values for utility bond yield spread

195. In general terms, the utility bond yield spread is calculated as a difference between the utility bond yield and GoC bond yield of the same maturity.

196. Consistent with her recommendations to use the 30-year GoC bond yield for the forecast risk-free rate, Dr. Villadsen recommended calculating the spread against the yield on 30-year utility bonds. Dr. Villadsen also advised that the utility bond yield spread should be estimated using a bond index that measures the market-based yields on a broad portfolio of Canadian utility bonds. She recommended the 30-year A-rated Canadian Utility Bond Index from Bloomberg (Series C29530Y) for this purpose. The spread can then be calculated as the current yield on 30-year A-rated Canadian utility bonds minus the current yield on the 30-year GoC bond, as of the same valuation date that the other "base" inputs are established in the formula. Dr. Villadsen stated the Commission may consider using the average yield over a historical period (e.g., the prior 15 days) to account for any potential one-day pricing effects.[201] In her evidence, Dr. Villadsen noted that the base spread at the end of November 2022 was 1.63 per cent.[202]

197. Other parties generally followed the same methodology as Dr. Villadsen for calculating the base utility bond yield spread, but differed in certain aspects. In Concentric's view, the utility

200 Bank of Canada CANSIM Series V39056.
201 Exhibit 27084-X0469.01, PDF page 82.
202 Exhibit 27084-X0469.01, PDF page 33 at Figure 6, PDF page 80.

bond yield spread should consider both A-rated and Baa-rated utility bonds because not all of the Alberta utilities have an A rating. Further, Concentric suggested that if the A and Baa-rated bond yield spreads differ, the Commission could average them or differentiate the resulting ROE separately for the A and sub-A rated utilities. Concentric stated that the base utility bond spread should be calculated based on market data at the end of December 2022.[203] D. D'Ascendis recommended setting the base spread using the average utility bond yield spread for the month of December 2022 in the amount of 1.64 per cent.[204] Dr. Cleary recommended using the actual, prevailing A-rated 30-year utility bond yield spread at the time the base ROE is set. For example, Dr. Cleary observed that the 30-year GoC bond yield of 2.85 per cent as of January 19, 2023, implied an A-rated utility yield spread of 1.58 per cent versus the spread of 1.31 per cent as of January 2020, and the average spread of 1.39 per cent over the January 3, 2003, to January 19, 2023 period.[205]

198. Regarding the utility bond yield spread for the upcoming test year, parties preferred to use the same methodologies they recommended for calculating the base value of the spread. The only difference was to use data from either September or October, i.e., at the same time the Commission computes the other parameters of the formulaic approach.

199. The Commission agrees with the mechanics of the utility bond yield spread calculations as described by Dr. Villadsen and used by most parties. The Commission also agrees with the selection of the 30-year A-rated Canadian Utility Bond Index from Bloomberg given the Commission's continued recognition of the importance of maintaining a target credit rating for the Alberta utilities in the A-range, as discussed in Section 7.3. As well, the Commission agrees with Dr. Villadsen that the base utility bond yield spread should be set based on data from the same time period that is used to establish the other "base" inputs in the formula. Therefore, the Commission will use the average utility bond yield spread for the month of February 2023 for the base value in the formula to be consistent with the time period selected for the data used to set the risk-free rate in Section 6.3.

200. The record of this proceeding includes some monthly data for the base utility bond yield spread but the average daily spread for February 2023 is not available on the record and its calculation requires proprietary data (Bloomberg Series C29530Y). Therefore, the Commission directs the ATCO Utilities, who sponsored the evidence of Dr. Villadsen, to calculate the average utility bond yield spread for the period from February 1 to February 28, 2023 using the calculation steps described in her evidence. The ATCO Utilities are further directed to provide these calculations and the resulting utility bond yield spread value as a post-disposition filing to this proceeding by October 18, 2023. Once confirmed by the Commission, this value will be used as the base utility bond yield spread ($SPRD_{base}$) in the approved formula.

201. Regarding the utility bond yield spread for the test year ($SPRD_t$), as was recommended by the majority of parties, the Commission will calculate the average difference between (i) the 30-year A-rated Canadian utility bond yield[206] and (ii) the long-term GoC bond yield[207] over the period October 1 to October 31 of the year preceding the test year.

[203] Exhibit 27084-X0315, PDF page 111.
[204] Exhibit 27084-X0390, PDF page 9.
[205] Exhibit 27094-X0320.02, PDF page 20.
[206] Bloomberg Series C29530Y.
[207] Bank of Canada CANSIM Series V39056.

7 Capital structure

7.1 Overview, approved deemed equity ratios for 2024, and review timeframe

202. To satisfy the fair return standard, the Commission is required to determine a fair return on the deemed equity component of invested capital. In this section, the Commission will determine the deemed equity ratios (also referred to as capital structure) – that is, the approved deemed portion (percentage) of rate base, net of no-cost capital, supported by common equity, for each of the utilities.

203. In this decision, the Commission maintains its previous approach of setting a uniform approved ROE, and then adjusting for any differences in risk among each of the utilities by adjusting the deemed equity ratios. The Commission will make adjustments, if required, to recognize changes in relative risk for each utility from the deemed equity ratios approved for 2023 in Decision 27084-D01-2022.

204. The Commission finds that no change is required to the deemed equity ratios set out in the 2018 GCOC decision. The Commission has determined that a deemed equity ratio of 37 per cent for both distribution and transmission utilities (with the exception of Apex, whose deemed equity ratio will remain at 39 per cent), including those which pay income tax and those which currently are income tax exempt or do not currently pay income tax, satisfies the fair return standard when combined with a 9.0 per cent approved notional ROE, and will enable the utilities to target a credit rating in the A-range.

205. The Commission considers that the deemed equity ratios should be reviewed every five years, or whenever the ROE formula is reviewed, whichever happens first, and finds that this promotes regulatory efficiency. In the case of any material changes in business risk that occur before the scheduled review of the deemed equity ratios approved in this decision, parties can request that the Commission undertake an earlier review as further described in Section 5.5.

206. The section is organized as follows. In Section 7.2, the Commission briefly outlines the deemed equity ratios recommended by the parties. In Section 7.3, the Commission addresses the targeting of credit ratings in the A-range. In Section 7.4, the Commission discusses credit metrics required by a typical pure-play regulated utility in Canada in order to achieve an A-range credit rating. The Commission also evaluates the credit metrics of the utilities having regard to significant financial parameters observed in Rule 005 filings and other evidence on the record of this proceeding, including the embedded average debt rate, depreciation as a percentage of invested capital, the income tax rate and the mid-year construction work in progress (CWIP) as a percentage of invested capital.

207. The Commission's consideration of the other factors relevant to the determination of an approved deemed equity ratio for each utility is in Section 7.5 with a review of the evidence in relation to changes in business risk that impact all the utilities. The Commission addresses the submissions of Fortis and Apex regarding their deemed equity ratios in Section 7.6.

7.2 Requested deemed equity ratios

208. The currently approved deemed equity ratios and the ratios recommended by parties for 2024 are set out in the following table.

Table 7. Currently approved deemed equity ratios and the deemed equity ratios recommended for 2024

	Last approved[208]	Recommended by Apex/ATCO Utilities/Fortis[209] Dr. Villadsen	Recommended by AltaLink/ EPCOR[210] D. D'Ascendis	Recommended by ENMAX[211] J. Coyne	Recommended by IPCAA[212] D. Madsen	Recommended by the UCA[213] Dr. Cleary
Electricity and natural gas transmission						
AltaLink	37		40		35	37
ATCO Electric Transmission	37	42			35	37
ATCO Pipelines	37	40				37
ENMAX Transmission	37			40	35	37
EPCOR Transmission	37		40		35	37
KainaiLink L.P.	37					
Lethbridge	37					
PiikaniLink L.P.	37					
Red Deer	37					
TransAlta	37					
Electricity and natural gas distribution						
Apex	39	44				39
ATCO Electric Distribution	37	40			35	37
ATCO Gas	37	40				37
ENMAX Distribution	37			40	35	37
EPCOR Distribution	37		40		35	37
Fortis	37	43			35	37

209. Dr. Villadsen conducted a credit ratio analysis to determine at what approved ROE and equity ratio combination the ATCO Utilities, Fortis and Apex would meet standard credit metric benchmarks from credit rating agencies such as the earnings before interest and taxes (EBIT) coverage, funds from operations (FFO) coverage, and FFO to debt metric. She also looked at DBRS and Moody's stated debt to rate base benchmarks in recommending a deemed equity percentage of about 40 per cent for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, and Fortis. She noted that F. Graves further recommended an "about 300 [bps] of equity percentage" increase in the equity ratio of Fortis, and Dr. Villadsen adopted that recommendation. Dr. Villadsen noted that at a 10 per cent ROE, ATCO Electric Transmission only met the FFO coverage and FFO to debt metric at about 42.5 per cent equity, so she recommended a deemed equity ratio of about 42 per cent equity for ATCO Electric Transmission.

208 Decision 27084-D01-2022, paragraph 59.

209 Exhibit 27084-X0469.01, PDF pages 104-105. Dr. Villadsen concurred with M. Tolleth that the deemed equity ratio for Apex be at least 400 basis points higher than the other utilities. Exhibit 27084-X0921, PDF page 2. Exhibit 27084-X0925, PDF page 17. Exhibit 27084-X0930, PDF page 20.

210 Exhibit 27084-X0390, PDF page 133. Exhibit 27084-X0928, PDF page 32.

211 Exhibit 27084-X0315, PDF page 19. Exhibit 27084-X0924, PDF page 32.

212 Exhibit 27084-X0292, PDF page 6. Exhibit 27084-X0918, PDF page 31.

213 Exhibit 27084-X0320.02, PDF page 6. Exhibit 27084-X0926, PDF page 34.

For Apex, Dr. Villadsen recommended an equity percentage at least 400 basis points higher than the benchmark based on the business risk analysis by M. Tolleth.[214]

210. Dr. Villadsen benchmarked her recommended deemed equity ratios against deemed equity ratios approved by other Canadian regulators, noting that the OEB approved a deemed equity ratio of 40 per cent for electric distributors and 36 to 40 per cent for gas distributors, while the British Columbia Utilities Commission has approved equity ratios of 38.5 per cent or more, and the Régie de l'énergie du Québec has approved equity ratios of between 38.5 and 46 per cent.[215] In the U.S., the average equity ratios in 2021-2022 for electric and gas distribution utilities were 50.2 and 51.1 per cent, respectively.[216]

211. M. Tolleth concluded that in order to satisfy the fair return standard, Apex's deemed equity ratio should be set at a premium to that of the generic benchmark gas distribution utility, in recognition of the higher market cost of capital associated with its small size and correspondingly elevated risk. He further concluded that based on fundamental finance principles and market evidence, any partially countervailing reduction to Apex's deemed equity ratio for purposes of "balancing" the higher market cost of debt experienced by small utilities such as Apex would not be consistent with the fair return standard. M. Tolleth submitted that it would be appropriate for the Commission to set Apex's deemed equity ratio at least 400 basis points (bps) above that of the "generic" Alberta gas distribution utility.[217]

212. F. Graves submitted that it is clear that the REA issue faced by Fortis presents a material financial risk, and can be offset by either allowing an ROE increase of 68 bps for Fortis, or an increase of about 300 bps in the deemed equity ratio of Fortis.[218]

213. D. D'Ascendis recommended that the deemed equity ratio applicable to AltaLink and EPCOR should be 40 per cent, which he submitted reflects the substantial increase in market risk since the 2018 GCOC proceeding, and increased business risk faced by AltaLink and EPCOR over that same period.[219] D. D'Ascendis submitted that his 40 per cent recommendation is reasonable when viewed in light of the OEB's approved deemed equity ratio in its annual formula ROE.[220]

214. J. Coyne stated that his assessment showed that while Alberta regulated utilities generally have comparable business risk to companies in the North American proxy group, they have much higher financial risk. He added that the current deemed equity ratio for Alberta utilities is low by Canadian standards and very low when compared to U.S. utilities, and recommended that the Alberta deemed equity ratio be raised to at least 40 per cent. J. Coyne submitted that his recommended 40 per cent deemed equity ratio is the same as that currently allowed for Ontario's electric distribution companies, and equivalent to the Canadian average allowed equity ratio for investor-owned utilities. He commented that a 40 per cent deemed equity ratio is conservative for ENMAX, as it is a non-taxable entity that does not receive the benefit of including income taxes

214 Exhibit 27084-X0469.01, PDF pages 7-8.
215 Exhibit 27084-X0469.01, PDF page 101.
216 Exhibit 27084-X0469.01, PDF page 89.
217 Exhibit 27084-X0377, PDF pages 5-6.
218 Exhibit 27084-X0479, PDF page 47.
219 Exhibit 27084-X0390, PDF page 133.
220 Exhibit 27084-X0390, PDF page 10.

in its revenue requirement, thereby reducing its cash flow metrics as compared to taxable entities.[221]

215. D. Madsen recommended a two per cent reduction to the equity thickness for the electric transmission and electric distribution utilities, from 37 per cent to 35 per cent. He submitted that the business and regulatory risk of the electric utilities has improved since the 2018 GCOC proceeding and that the financial risks and performance of the utilities remains strong. D. Madsen added that the growth rates of the utilities have slowed significantly in recent years which, all else being equal, reduces risk.[222]

216. Dr. Cleary commented that Alberta utilities have low risk as shown by their consistent "low business risk" ratings, low earnings volatility, and most importantly, the ability to generate earned ROEs above the approved ROEs for the last 17 years. Dr. Cleary recommended no change in the approved deemed equity ratios but, rather, emphasized the impetus for a reduction in the approved ROE, based on his belief that it continues to be "well above the actual cost of equity for Alberta utilities." Dr. Cleary submitted that his recommendations are reasonable, and are supported by the credit metric analysis provided by R. Bell.[223]

217. R. Bell noted that if the achieved ROE increases, the level of the deemed equity ratio required to achieve the credit metric targets decreases. He recommended that if the approved ROE increases, the deemed equity ratio be decreased.[224]

7.3 Targeted credit ratings

218. The targeting of credit ratings in the A-range is one of the factors the Commission will continue to use as part of its determination of the deemed equity ratios for 2024 and beyond.

219. Credit ratings assess the credit worthiness of a firm as determined by a credit rating agency. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments and to repay debt principal, allowing the company to borrow at a lower interest rate.

220. Historically, the Commission has recognized the importance of maintaining a target credit rating for the utilities in Alberta in the A-range,[225] and continues to do so. This target credit rating is especially important when interest rates rise. The use of the A-range credit rating target is a factor that respects the financial integrity, capital attraction and comparability aspects of the fair return standard.

221. The Commission finds that, generally, most utilities in Alberta have had little difficulty raising debt and equity financing on satisfactory terms since the 2018 GCOC proceeding, all while maintaining the credit ratings from S&P that were in place during the 2018 GCOC proceeding. The one exception is ENMAX's credit rating, which was decreased largely because of a debt-financed acquisition that was not associated with ENMAX's Alberta operations.[226]

[221] Exhibit 27084-X0315, PDF pages 4-5.
[222] Exhibit 27084-X0292, PDF page 62.
[223] Exhibit 27084-X0320.02, PDF pages 5-6.
[224] Exhibit 27084-X0318, PDF page 20.
[225] Decision 22570-D01-2018, PDF page 145, paragraph 689.
[226] Exhibit 27084-X0926, PDF page 26, citing Transcript, Volume 2, page 294, line 4 to page 296, line 1.

7.4 Credit metrics

222. Dr. Villadsen,[227] D. D'Ascendis,[228] D. Madsen[229] and Dr. Cleary[230] each took the position that their respective recommended deemed equity ratios either considered credit metrics, or were supported by a credit metric analysis. In past GCOC decisions, the Commission has placed weight on credit metrics.

223. Credit metrics (or financial ratios) are an important, although not the only, component that credit rating agencies consider when assessing the risk of any particular company and assigning a credit rating. As noted in the 2018 GCOC decision, the Commission has historically assessed three principal credit metrics:[231]

- **EBIT coverage:** This is referred to as an interest coverage ratio. In the Commission's credit metric model, it is calculated by grossing up the net income by the statutory income tax rate, adding the return on debt amount, and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate.

- **FFO coverage:** This is also an interest coverage ratio. In the Commission's credit metric model, it is calculated by adding the return on debt amount, the net income and the depreciation collected and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate. It is important to note that in the Commission's credit model, the interest expense associated with the CWIP balance is not included in the numerator because it is based on the assumption that there is no CWIP included in rate base.

- **FFO/debt:** S&P compares this payback ratio against benchmarks to derive the preliminary cash flow/leverage assessment for a company. S&P notes that this ratio is also useful in determining the relative ranking of the financial risk of companies.[232] In the Commission's credit metric model, it is calculated by adding the net income and the depreciation collected and dividing the resulting figure by the sum of the deemed mid-year debt for rate base and CWIP.

224. In the 2018 GCOC decision, the Commission observed that the credit rating metrics required for an Alberta utility to achieve a credit rating in the A-range had not changed since the 2016 GCOC decision. Those guidelines were EBIT coverage of 2.0, FFO coverage of 2.0 to 3.0, and an FFO/debt ratio range of 9.0 to 13.0.[233] The Commission indicated that those guidelines assumed a credit rating assessment of "strong" for the Alberta regulatory environment. The Commission added that "the guidelines do not take into account potential adjustments to the

227 Exhibit 27084-X0469.01, PDF pages 5-6.
228 Exhibit 27084-X0390, PDF page 121.
229 Exhibit 27084-X0292, PDF page 62.
230 Exhibit 27084-X0320.02, PDF page 6.
231 Decision 22570-D01-2018, PDF page 146, paragraph 698.
232 Proceeding 20622, Exhibit 20622-X0089, PDF page 73.
233 Decision 22570-D01-2018, PDF page 164, paragraph 775. The guidelines were set out in Table 15 of the decision, on PDF page 165.

deemed equity ratios that may be necessary in the Commission's judgment to take account of the current trend of "negative" noted by credit rating agencies and in particular by S&P."[234]

225. Dr. Villadsen concurred with S&P that it is important to have credit metrics that are not marginally satisfactory.[235] She submitted that to ensure sufficient cushion against negative occurrences, it is important to establish expected credit metrics that are not up against the lower bound, but instead near the middle.[236]

226. N. Martin indicated that under S&P's methodology, regulatory advantage is a key contributor to a utility's credit rating, and submitted that a lower assessment of the regulatory regime leads to higher business risk, and with higher business risk, stronger credit metrics are required to maintain the same rating.[237] N. Martin stated that late in 2020, S&P lowered its assessment of the Alberta "regulatory advantage" from "strong" to "strong/adequate," citing low returns, regulatory lag and the risk of having to absorb undepreciated capital costs of stranded assets. She submitted that simply reducing regulatory lag by improving regulatory efficiency will not be sufficient to improve the regulatory advantage assessment back to "strong."[238]

227. N. Martin submitted that the Commission's sole reliance on ratio targets taken from S&P's low volatility table without also taking into account the medial volatility table is not prudent. She indicated that given Alberta's regulatory advantage is currently only strong/adequate, a utility rating will be based on the low volatility table only if S&P views the utility's business strategy as positive, thus moving the company-specific final regulatory advantage score to strong from strong/adequate.[239]

228. The Commission acknowledges that credit metric targets do not assure an A-range credit rating, but it is satisfied that credit metrics should be considered in the assessment of deemed equity ratios. The Commission recognizes that, among other things, the process of setting credit metrics required to maintain an A-range credit rating for the utilities in Alberta is a function of market dynamics and credit agency analysis of macro-economic trends, Canadian utility industry specific variables and future investor expectations, applied to an assessment of the relative risk of the utility sector, and perceptions of the regulatory environment.

229. Credit metrics reflect past market expectations as well as anticipated market expectations, given an assessment of current economic conditions, the information and assumptions employed in conducting the analysis, and judgment of relative risk. The element of judgment is reflected to some degree in the differing credit metrics employed and the breadth of ranges used by various credit rating agencies and market analysts. Further, the application of utility sector credit metrics to a particular Alberta utility involves a further element of judgment on factors such as the Alberta regulatory climate.

230. From a practical perspective, however, credit metrics affect investor risk perceptions and consequently may affect market behaviour. The Commission considers the credit metrics reflected in credit rating and market analyst reports to be generally reflective of future

234 Decision 22570-D01-2018, PDF page 164, paragraph 775.
235 Exhibit 27084-X0761.02, PDF page 76.
236 Exhibit 27084-X0761.02, PDF page 80.
237 Exhibit 27084-X0316, PDF page 7.
238 Exhibit 27084-X0316, PDF page 6.
239 Exhibit 27084-X0316, PDF page 25.

expectations of utility debt and of equity investors with respect to credit metric fundamentals. This observation is supported generally by a review of actual market behaviour.

231. In the 2016 GCOC decision and the 2018 GCOC decision, the Commission placed greater weight on S&P's credit metric benchmarks for FFO coverage and FFO/debt, using the low volatility table. During the 2018 GCOC proceeding, the Alberta regulatory advantage was rated by S&P as "strong" with a trend of "negative." Evidence was submitted during the current proceeding that late in 2020, S&P lowered its assessment of the Alberta regulatory advantage from "strong" to "strong/adequate." AltaLink and EPCOR submitted that this made the use of the FFO/debt range from S&P's low volatility table inapplicable in this proceeding. J. Coyne submitted that a drop in the regulatory advantage can require stronger credit metrics to maintain a given credit rating. However, the Commission finds that this lower assessment of the Alberta regulatory advantage has not prevented S&P from assessing financial credit metrics for a number of the utilities in Alberta (AltaLink L.P., AltaLink Investments L.P., CU Inc. and Fortis) using the low volatility table.[240]

232. As explained by N. Martin, even with a regulatory advantage assessment of "strong/adequate," S&P's low volatility table will continue to be available, but only if S&P views the utility's business strategy as positive.[241] Given that S&P has viewed the business strategy of a number of the utilities in Alberta as positive, as evidenced by S&P's use of the low volatility table for these utilities, the Commission agrees with the UCA[242] that using the medial volatility table in establishing credit metric thresholds for an A-range rating is unnecessary, and would reward the utilities whose business strategy is not viewed as positive by S&P. The Commission finds that the continued use of the low volatility table is warranted in assessing the credit metrics.

233. The Commission agrees with Dr. Villadsen's submission that it is important to establish credit metrics that are not up against the lower bound, but are nearer to the mid-point of the range. The resulting EBIT coverage ratios at 37 per cent deemed equity are 2.2 for non-taxable utilities and 2.6 for taxable utilities. The DBRS range for EBIT coverage is 1.8 to 2.8, which places the non-taxable utilities just under the mid-point of the range, and places the taxable utilities towards the top of the range. The resulting FFO coverage ratios at 37 per cent deemed equity are 4.4 for the distribution utilities and 3.7 for the transmission utilities. Both of these exceed the 2.0 to 3.0 range of S&P's low volatility table and even exceed the lower bound of the 3.0 to 5.0 range of S&P's medial volatility table. S&P's low volatility table has a range of 9.0 per cent to 13.0 per cent for the FFO/debt ratio. The resulting FFO/debt ratios at 37 per cent deemed equity are 14.2 per cent for the distribution utilities and 11.5 per cent for the transmission utilities, both of which are well above the lower bound of 9.0 per cent, with the distribution utilities being within the range of the medial volatility table.

7.4.1 Equity ratios associated with credit metrics

234. In the 2018 GCOC decision (tables 11-14), the Commission provided a sensitivity analysis to illustrate the effect of a range of equity ratios on the three principal credit metrics for

240 Exhibit 27084-X0926, PDF page 26, citing Exhibit 27084-X0273, PDF pages 134 and 143 (for AltaLink L.P. and AltaLink Investments L.P.), citing Exhibit 27084-X0279, PDF page 66 (for CU Inc.), and citing Exhibit 27084-X0286, PDF page 6 (for Fortis).
241 Exhibit 27084-X0316, PDF page 25.
242 Exhibit 27084-X0926, PDF page 26, paragraph 92.

the distribution utilities and the transmission utilities, using income tax rates of 27 per cent and zero. The analysis was based on certain input parameters associated with the affected utilities. The Commission has prepared a similar analysis as part of this decision.

235. The parameter values used by the Commission in the 2018 GCOC decision, as well as the parameter values the Commission is using in this proceeding, are set out in Table 8 below. The Commission's reasons for selecting the updated parameter values follow.

Table 8. Parameters for calculating credit metrics

Parameter	Parameter values applied in this decision – taxable distribution utilities	Parameter values applied in this decision – taxable transmission utilities	Parameter values applied in 2018 GCOC decision – taxable distribution utilities	Parameter values applied in 2018 GCOC decision – taxable transmission utilities
	(%)			
Embedded average debt rate	4.20	4.20	4.70	4.70
ROE	9.00	9.00	8.50	8.50
Income tax rate	23.00	23.00	27.00	27.00
Depreciation	5.88	4.11	5.85	4.20
CWIP	2.89	3.10	3.21	5.00

236. In arriving at the updated parameters, the Commission reviewed the actual parameters from 2022 and 2021, as set out in the 2023 and 2022 Rule 005 filings that were submitted as part of this proceeding.

237. The ROE input parameter is common to all utilities, as is the income tax rate input parameter for those utilities that are not income tax exempt. The Commission has summarized the embedded average debt rates, depreciation rates and CWIP percentages for each utility in Table 9.

Table 9. Embedded average debt rates, depreciation rates and CWIP percentages by utility

Utility	Invested capital ($000)	Debt cost (%)	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
ATCO Electric – distribution				
2023 Rule 005	2,670,900	4.43	5.14	4.47
2022 Rule 005	2,598,600	4.52	5.05	3.66
Fortis – distribution				
2023 Rule 005	3,929,400	4.44	6.36	1.78
2022 Rule 005	3,777,200	4.42	6.24	1.72
ENMAX – distribution				
2023 Rule 005	1,812,900	3.57	4.95	1.72
2022 Rule 005	1,672,700	3.48	4.93	2.21
EPCOR – distribution				
2023 Rule 005	1,652,300	4.11	4.20	1.45
2022 Rule 005	1,542,500	4.13	4.21	1.73
ATCO Gas – distribution				
2023 Rule 005	2,872,900	4.42	7.57	4.68
2022 Rule 005	2,855,900	4.48	7.24	3.50
Apex – distribution				
2023 Rule 005	452,800	4.27	5.21	1.80
2022 Rule 005	423,800	4.23	5.17	2.81
AltaLink – transmission				
2023 Rule 005	7,421,600	3.89	3.99	1.55
2022 Rule 005	7,469,200	3.86	3.91	1.49
ATCO Electric – transmission				
2023 Rule 005	4,841,400	4.53	4.31	4.84
2022 Rule 005	4,980,300	4.56	4.19	3.23
ENMAX – transmission				
2023 Rule 005	774,100	3.54	3.78	9.70
2022 Rule 005	750,600	3.49	3.67	5.83
EPCOR – transmission				
2023 Rule 005	761,000	4.53	3.64	5.48
2022 Rule 005	732,500	4.60	3.50	5.25
ATCO Pipelines – transmission				
2023 Rule 005	2,486,600	3.97	4.36	1.59
2022 Rule 005	2,344,600	4.06	4.33	2.14
Simple average				
2023 Rule 005		**4.15**	**4.86**	**3.55**
2022 Rule 005		**4.17**	**4.77**	**3.05**

238. In Table 10 below, the Commission presents additional calculations based on the information presented in Table 9. There is no simple average or weighted average for gas transmission utilities presented separately in Table 10 because there is only one gas transmission utility, i.e., ATCO Pipelines.

Table 10. Additional analysis of information included in Table 9

Utility	Debt cost (%)	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
Simple average – overall			
2023 Rule 005	4.15	4.86	3.55
2022 Rule 005	4.17	4.77	3.05
Weighted average - overall			
2023 Rule 005		4.91	3.01
2022 Rule 005		4.80	2.54
Simple average – distribution utilities			
2023 Rule 005	4.21	5.57	2.65
2022 Rule 005	4.21	5.47	2.60
Weighted average – distribution utilities			
2023 Rule 005		5.88	2.89
2022 Rule 005		5.77	2.61
Simple average – transmission utilities			
2023 Rule 005	4.09	4.01	4.63
2022 Rule 005	4.11	3.92	3.59
Weighted average – transmission utilities			
2023 Rule 005		4.11	3.10
2022 Rule 005		4.03	2.49
Simple average – electric distribution utilities			
2023 Rule 005	4.14	5.16	2.36
2022 Rule 005	4.14	5.11	2.33
Weighted average – electric distribution utilities			
2023 Rule 005		5.43	2.43
2022 Rule 005		5.36	2.33
Simple average – gas distribution utilities			
2023 Rule 005	4.35	6.39	3.24
2022 Rule 005	4.35	6.21	3.15
Weighted average – gas distribution utilities			
2023 Rule 005		7.25	4.29
2022 Rule 005		6.98	3.41
Simple average – electric transmission utilities			
2023 Rule 005	4.12	3.93	5.39
2022 Rule 005	4.13	3.82	3.95
Weighted average – electric transmission utilities			
2023 Rule 005		4.07	3.38
2022 Rule 005		3.98	2.55

239. In its credit metric calculations, the Commission adopted the following five parameters: ROE value, embedded average debt rate, income tax rate, depreciation as a percentage of invested capital, and mid-year CWIP as a percentage of invested capital.

ROE value

240. The Commission has applied the notional ROE value of 9.0 per cent in its credit metric calculations, consistent with its findings in Section 6.4.5.

Embedded average debt rate

241. The simple average of the embedded average debt rates is 4.17 per cent based on the 2022 Rule 005 reports, and 4.15 per cent based on the 2023 Rule 005 reports. The simple average of the distribution utilities based on both Rule 005 reports was 4.21 per cent. The simple

average of the transmission utilities was 4.11 per cent based on the 2022 Rule 005 reports, and 4.09 per cent based on the 2023 Rule 005 reports.

242. The Commission finds that the use of 4.20 per cent for the embedded average debt rate is reasonable. While this figure is higher than the overall simple average debt rate for all the utilities based on the 2023 Rule 005 reports, it errs on the conservative side, because it results in lower EBIT coverage and FFO coverage ratios.

Income tax rate

243. The Commission is analyzing credit metrics using both the current combined statutory income tax rate of 23 per cent, and a rate of zero. The income tax rate of zero accounts for the income-tax-exempt utilities, as well as those utilities that expect to have no taxable income.

Depreciation as a percentage of invested capital

244. The amount of depreciation collected through rates is included in the calculation of the FFO component of the FFO/debt and FFO coverage ratios.

245. The weighted average depreciation rate as a percentage of invested capital for the distribution utilities based on the 2023 Rule 005 reports is 5.88 per cent, and is 4.11 per cent for the transmission utilities, both as shown in Table 10. The Commission uses these figures in its credit metric calculations, because they represent the most recent data on the record of the proceeding.

Mid-year CWIP as a percentage of invested capital

246. The weighted average mid-year CWIP as a percentage of invested capital for the distribution utilities based on the 2023 Rule 005 reports is 2.89 per cent, and is 3.10 per cent for the transmission utilities, both as shown in Table 10. The Commission uses these figures in its credit metric calculations, because they represent the most recent data on the record of the proceeding.

247. Based on the credit metric parameters discussed above, the Commission has updated its credit metric calculations at various equity ratios from the calculations set out in the 2018 GCOC decision. As previously mentioned, to address the impact of zero income tax on credit metrics, the Commission has also provided credit metric calculations at various equity ratios, which reflect an income tax rate of zero. The revised calculations are set out in tables 11-14.

Table 11. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision)

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision
30	2.1	2.0	3.8	3.4	11.9	11.6
31	2.2	2.0	3.9	3.5	12.2	11.9
32	2.2	2.1	4.0	3.6	12.5	12.2
33	2.3	2.2	4.0	3.6	12.8	12.5
34	2.4	2.2	4.1	3.7	13.2	12.8
35	2.4	2.3	4.2	3.8	13.5	13.2
36	2.5	2.3	4.3	3.8	13.8	13.5
37	2.6	2.4	4.4	3.9	14.2	13.8
38	2.6	2.4	4.4	4.0	14.6	14.2
39	2.7	2.5	4.5	4.1	15.0	14.6
40	2.8	2.6	4.6	4.1	15.4	14.9
41	2.9	2.6	4.7	4.2	15.8	15.3
42	2.9	2.7	4.8	4.3	16.2	15.7
43	3.0	2.8	4.9	4.4	16.6	16.2
44	3.1	2.9	5.0	4.5	17.1	16.6
45	3.2	2.9	5.1	4.6	17.5	17.0

Table 12. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of zero

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable
30	1.9	1.7	3.8	3.4	11.9	11.6
31	1.9	1.8	3.9	3.5	12.2	11.9
32	2.0	1.8	4.0	3.6	12.5	12.2
33	2.0	1.8	4.0	3.6	12.8	12.5
34	2.0	1.9	4.1	3.7	13.2	12.8
35	2.1	1.9	4.2	3.8	13.5	13.2
36	2.1	2.0	4.3	3.8	13.8	13.5
37	2.2	2.0	4.4	3.9	14.2	13.8
38	2.2	2.0	4.4	4.0	14.6	14.2
39	2.3	2.1	4.5	4.1	15.0	14.6
40	2.4	2.1	4.6	4.1	15.4	14.9
41	2.4	2.2	4.7	4.2	15.8	15.3
42	2.5	2.2	4.8	4.3	16.2	15.7
43	2.5	2.3	4.9	4.4	16.6	16.2
44	2.6	2.3	5.0	4.5	17.1	16.6
45	2.7	2.4	5.1	4.6	17.5	17.0

Table 13. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision)

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision
30	2.1	2.0	3.2	2.9	9.4	9.2
31	2.2	2.0	3.3	3.0	9.7	9.4
32	2.2	2.1	3.3	3.0	10.0	9.7
33	2.3	2.1	3.4	3.1	10.2	10.0
34	2.4	2.2	3.5	3.1	10.5	10.2
35	2.4	2.2	3.5	3.2	10.8	10.5
36	2.5	2.3	3.6	3.3	11.1	10.8
37	2.6	2.3	3.7	3.3	11.5	11.1
38	2.6	2.4	3.8	3.4	11.8	11.4
39	2.7	2.5	3.9	3.4	12.1	11.7
40	2.8	2.5	3.9	3.5	12.5	12.1
41	2.8	2.6	4.0	3.6	12.8	12.4
42	2.9	2.7	4.1	3.7	13.2	12.8
43	3.0	2.7	4.2	3.7	13.6	13.1
44	3.1	2.8	4.3	3.8	14.0	13.5
45	3.2	2.9	4.4	3.9	14.4	13.9

Table 14. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of zero

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable
30	1.9	1.7	3.2	2.9	9.4	9.2
31	1.9	1.7	3.3	3.0	9.7	9.4
32	1.9	1.8	3.3	3.0	10.0	9.7
33	2.0	1.8	3.4	3.1	10.2	10.0
34	2.0	1.8	3.5	3.1	10.5	10.2
35	2.1	1.9	3.5	3.2	10.8	10.5
36	2.1	1.9	3.6	3.3	11.1	10.8
37	2.2	2.0	3.7	3.3	11.5	11.1
38	2.2	2.0	3.8	3.4	11.8	11.4
39	2.3	2.1	3.9	3.4	12.1	11.7
40	2.4	2.1	3.9	3.5	12.5	12.1
41	2.4	2.1	4.0	3.6	12.8	12.4
42	2.5	2.2	4.1	3.7	13.2	12.8
43	2.5	2.3	4.2	3.7	13.6	13.1
44	2.6	2.3	4.3	3.8	14.0	13.5
45	2.7	2.4	4.4	3.9	14.4	13.9

248. The Commission has undertaken the above calculations in light of the credit metric findings in Section 7.4. Table 15 sets out the guidelines established by the Commission in this section to achieve a credit rating in the A-range, which assumes S&P viewing the utility's business strategy as positive, which moves the utility's final regulatory advantage score to strong and enables the use of S&P's low volatility table.

249. Table 15 sets out the minimum equity ratio that would be required, in conjunction with an approved ROE of 9.0 per cent, for distribution and transmission utilities in Alberta with an income tax rate of 23 per cent, as well as distribution and transmission utilities in Alberta with an income tax rate of zero per cent, to meet the corresponding credit ratio threshold or range used by the Commission to establish a credit rating in the A-range. For example, as shown in Table 15, a distribution utility in the 2024 GCOC proceeding that has an income tax rate of zero per cent, would require a deemed equity ratio of 32 per cent to achieve an EBIT coverage ratio of 2.0. That same utility would require a deemed equity ratio somewhere below 30 per cent, in order to achieve an FFO coverage ratio of 2.0, and an FFO coverage ratio of 3.0. Finally, that same utility would require a deemed equity ratio below 30 per cent, in order to achieve an FFO/debt ratio of 9.0, while it would require a deemed equity ratio of 34 per cent to achieve an FFO/debt ratio of 13.0.

Table 15. Commission guidelines for equity ratios to achieve a credit rating in the A-range

Credit metric guideline	2.0 EBIT coverage	2.0 FFO coverage	3.0 FFO coverage	9.0 FFO/debt ratio	13.0 FFO/debt ratio
			(%)		
2023 distribution utilities – 23 per cent income tax rate	Below 30	Below 30	Below 30	Below 30	34
2018 distribution utilities – 27 per cent income tax rate	30	Below 30	Below 30	Below 30	35
2023 distribution utilities – zero per cent income tax rate	32	Below 30	Below 30	Below 30	34
2018 distribution utilities – zero per cent income tax rate	36	Below 30	Below 30	Below 30	35
2023 transmission utilities – 23 per cent income tax rate	Below 30	Below 30	Below 30	Below 30	42
2018 transmission utilities – 27 per cent income tax rate	30	Below 30	31	30	43
2023 transmission utilities – zero per cent income tax rate	33	Below 30	Below 30	Below 30	42
2018 transmission utilities – zero per cent income tax rate	37	Below 30	31	30	43

250. Based on the results of its credit metric calculations, the Commission continues to find, as it did in the 2016 and 2018 GCOC decisions, "that absent differences in business risk, the continued perpetuation of the historical gap in equity ratios between the higher equity ratio awarded to distribution utilities and the lower equity ratio awarded to transmission utilities is no longer warranted."[243] Using the credit metric inputs described previously, including the notional ROE of 9.00 per cent, and with the approved deemed equity ratio of 37 per cent, the distribution

[243] Decision 22570-D01-2018, PDF page 165, paragraph 777. Decision 20622-D01-2016, PDF page 104, paragraph 433.

and transmission utilities meet the Commission's guidelines to achieve a credit rating in the A range.

7.5 Overall assessment of business risk

251. In this section of the decision, the Commission considers whether business risk factors impacting all the utilities, or a particular segment of the utilities, require the Commission to adjust the deemed equity ratios approved in the 2018 GCOC decision.

252. Utility company witnesses testified that business risk was an important factor underlying their recommended deemed equity ratios. They highlighted the increased business risk to utilities due to elevated cybersecurity concerns, the decarbonization polices of all levels of government along with the increased risk associated with macroeconomic factors of rising inflation, interest rates, and capital costs. More broadly, the Alberta utilities suggested that the overall utilities sector has seen a decline in credit ratings and that Alberta utilities are disadvantaged relative to other Canadian utilities and North American comparators that benefit from regulators approving higher ROEs and equity ratios. Two utilities, Fortis and Apex, argued that they warranted higher equity ratios than other Alberta utilities because of their company-specific business risks.

253. Contrary to the submissions of the utilities, interveners suggested that Alberta utilities operated in a low business risk environment and recommended that equity ratios be maintained at the levels set in the 2018 GCOC or decreased.

254. All parties provided their perspectives on the Alberta-specific utility asset disposition (UAD) related or stranded asset risk and the impact of a recent Court of Appeal decision,[244] which dealt with recovery of costs of stranded assets destroyed by wildfires.

255. Based on the evidence on the record, the Commission identified (i) various macroeconomic factors; (ii) regulatory risk; (iii) UAD risk; and (iv) decarbonization risk as the main grounds offered by utilities for an upward adjustment to equity thickness for all utilities. A discussion of these issues is provided below, followed by a discussion of the utility-specific risks of Fortis and Apex.

7.5.1 Macroeconomic factors

256. While the Commission acknowledges that interest rates and inflation have increased since the 2018 GCOC, resulting in higher capital costs, it is not persuaded that these factors warrant an increase in approved ROEs or deemed equity ratios above those currently in place. In Alberta, the utilities are largely isolated from broader macroeconomic factors because utility regulation provides a reasonable opportunity to recover prudently incurred costs, including those directly and indirectly affected by higher interest and inflation rates.[245] Specifically, PBR plans for Alberta distribution utilities include inflation as a direct input into the PBR formula, while cost-of-service (COS) regulation that applies to transmission utilities affords those utilities 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.[246]

[244] *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.
[245] Exhibit 27084-X0918, PDF page 14, citing Transcript, Volume 2, pages 504-509.
[246] Exhibit 27084-X0918, PDF page 14.

7.5.2 Regulatory risk

257. The utilities claim that regulatory risks in Alberta have increased since 2018. Among the risks they have identified are lower deemed equity ratios and lower approved ROEs than those awarded in other North American jurisdictions, regulatory lag, stranded asset risk, and one credit rating agency's lowering of its assessment of the Alberta regulatory advantage from "most credit supportive" (strong) to "highly credit supportive" (strong/adequate).[247]

258. The Commission finds these claims of higher regulatory risk in Alberta are without merit. 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 (that themselves have been determined to be just and reasonable independently of, and entirely without regard to, any additional profits arising from such cost-cutting initiatives) during each PBR term or COS test period.[248] The Commission notes parenthetically in this regard, that, with very few exceptions, Alberta utilities have, on average, consistently earned returns above their approved ROE during the past 17 years by responding positively to existing incentives to drive costs lower and secure the benefit of savings thus generated until the next rate case or PBR term. Moreover, regulatory lag, regulatory costs, red tape and related aspects of regulatory burden have been significantly reduced in Alberta since the 2018 GCOC proceeding.[249]

259. On balance, the Commission finds that the regulatory environment for Alberta utilities is broadly supportive, and that the level of regulatory risk faced by the Alberta utilities is consistent with the level of regulatory risk they faced at the time of the 2018 GCOC proceeding, if not distinctly lower. The issue of stranded asset or UAD-related risk, meanwhile, is dealt with separately in the next section.

7.5.3 Utility asset disposition risk and the impact of the Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129

260. In a letter dated June 6, 2023,[250] the Commission requested that parties provide submissions on the impact of the Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*[251] (the Wildfires Decision) on business risk related to the recovery of costs associated with assets that are stranded due to obsolescence.

261. Most parties submitted that it was premature to assess the impact of the Wildfires Decision – which dealt with the recovery of assets destroyed by a natural disaster – on the recovery of stranded assets made obsolete by technology or other causes. This is because the Court of Appeal sent the matter back to the Commission to determine, and the Commission has not yet rendered its decision. Until the Commission reconsiders its decision on the UAD framework, utilities argued that they were exposed to uncertainty and UAD-related cost disallowance. The CCA stated that the Wildfires Decision likely reduces the business risk of

[247] Exhibit 27084-X0316, PDF pages 17-18; Exhibit 27084-X0390, PDF page 97.
[248] As noted in footnote 192, The Commission recognizes that utilities subject to COS regulation do not have the same incentives and returns as utilities subject to PBR.
[249] AUC website: https://www.auc.ab.ca/auc-exceeds-government-of-alberta-target-with-48-per-cent-reduction-in-regulatory-red-tape-requirements/#hq=red%20tape%20reduction
[250] Exhibit 27084-X0906, AUC letter – Additional details regarding argument process.
[251] *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.

utilities as it appears to directionally increase the likelihood of recovery of costs from customers due to weather and natural disaster events.[252]

262. Apart from any impact the Commission's reconsideration of the Wildfires Decision may have, there is no compelling basis to suggest that UAD-related risk has changed since the decision in the 2018 GCOC. The Commission also finds that its 2016 GCOC decision[253] is still applicable to the present proceeding. There, the Commission found that regulatory risk for investors in Alberta utilities had increased by some incremental but unquantifiable amount as a result of the Stores Block-Utility Asset Disposition line of decisions.[254]

7.5.4 Decarbonization

263. The Commission finds that while there are numerous legislative and other initiatives at all levels of government to reduce carbon emissions,[255] the record of this proceeding does not establish that progress towards decarbonization that has taken place or is reasonably likely to take place in the foreseeable future, poses an immediate or imminent risk to Alberta utilities warranting an adjustment to their equity thickness.

264. The utilities argued that, generally, carbon reduction goals are more aggressive and difficult in Alberta than decarbonization policies in other jurisdictions. Examples include the current federal government's stated intention to decarbonize the electricity grid by 2035 and the transition to electric heating now overwhelmingly provided by natural gas. The utilities asserted that if decarbonization creates stranded assets (as it is designed to), the current recovery mechanism (the UAD line of cases) as applied by the Commission to date is much less supportive than in other jurisdictions, thus increasing the utilities' business risk.

265. Interveners disagreed with this view, stating that absent actual evidence that decarbonization increases the risk to Alberta utilities, there should be no resulting adjustment to equity thickness.[256] To the contrary, they submitted that decarbonization and net-zero policies would benefit electric utilities because in order to achieve these goals, additional investment in distribution infrastructure, for example, changes to accommodate wide penetration of electric vehicle charging would be required, thus increasing the utility's rate base and load. Interveners did acknowledge that there may be impacts on natural gas utilities but that the actual impact was uncertain at this time given the present status of hydrogen injection into the natural gas distribution stream. They concluded that Alberta's overwhelming reliance on natural gas for space heating is not likely to change in the near term because of the very high cost of transitioning from natural gas to electricity.[257]

266. While the Commission appreciates that decarbonization is a potential risk to Alberta utilities, there is little or no evidence on the record of the current proceeding that shows that natural gas or electric utilities have experienced any significant increases in risk related to customers changing behaviour, a reduction in natural gas demand, complications related to electrification, or factors that might impact their operations. Absent any evidence that clearly shows the impact to the Alberta utilities' business risk from decarbonization, the Commission

252 Exhibit 27084-X0919, PDF page 26, paragraph 82.
253 Decision 20622-D01-2016.
254 Decision 20622-D01-2016, PDF pages 120-121.
255 Exhibit 27084-X0479, PDF pages 29-31.
256 Exhibit 27084-X0934, PDF page 5.
257 Exhibit 27084-X0926, PDF pages 27-28.

finds that adjusting the deemed equity ratio for Alberta utilities to account for any such impact is unwarranted, or at a minimum, premature.

7.6 Utility-specific business risks

7.6.1 Determination of Commission-approved deemed equity ratio for Fortis

267. Fortis requested a 300 bps premium above the generic deemed equity ratio for an Alberta utility on the basis that it faces increased business and regulatory risk not experienced by other Alberta utilities. Specifically, Fortis argued that these risks arise from the increased competition for customers from rural electrification associations (REAs) and the removal from its recoverable revenue requirement of over $10 million on an ongoing annual basis beginning in 2023. The removal of the $10 million from revenue requirement resulted from a Commission decision[258] which was subsequently upheld by the Court of Appeal of Alberta.[259] Fortis estimated that this will reduce Fortis's earned ROE by approximately 68 bps and erode its cash flow credit metrics, which might result in a credit rating downgrade.[260]

268. The Commission is not persuaded that an increase in the equity thickness is required. As pointed out by the UCA, the threat of competition from REAs is negligible at present. A net total of just 35 sites has transferred to REAs since 2018, which the UCA calculated as 0.006 per cent of customers in Fortis's service territory.[261] The Commission is not persuaded that there is a serious threat of customer defections from Fortis to REAs. Further, the Commission finds that increasing Fortis's equity thickness to counter competition from REAs would place Fortis at a competitive disadvantage relative to REAs as an increase in equity thickness will result in an increased revenue requirement, and ultimately higher rates for Fortis's customers.

269. In addition, increasing the equity thickness by 300 bps in order to offset the removal of $10 million from Fortis's revenue requirement is compensating Fortis indirectly for what the Commission does not have the authority to do directly, that is, to compensate Fortis for costs attributable to the REAs' use of Fortis's system from Fortis's own regulated customers.[262]

270. In upholding the Commission's decision to deny recovery of these costs from Fortis customers, the Court of Appeal in the EQUS REA decision stated:[263]

> [23] The Commission correctly determined that FortisAlberta cannot recover from its customers the difference between the costs FortisAlberta incurs when rural electrification associations use FortisAlberta's distribution system to provide electricity to its members and the costs rural electrification associations incur when FortisAlberta uses rural electrification associations' distribution systems to provide electricity to its customers. There is no sound reason why FortisAlberta's customers should subsidize the members of rural electrification associations.

258 Decision 25916-D01-2021: FortisAlberta Inc., 2022 Phase II Distribution Tariff Application, Proceeding 25916, July 8, 2021.
259 *Equs Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142.
260 Exhibit 27084-X0479, PDF page 47.
261 Exhibit 27084-X0926, PDF page 31, paragraph 110.
262 This point was also made by the UCA and IPCAA – see Exhibit 27084-X0926, PDF page 30, paragraph 108; Exhibit 27084-X0918, PDF pages 20-21, paragraph 64.
263 *Equs Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142.

271. Granting an increase in Fortis's deemed equity ratio would result in such subsidization, although in an indirect as opposed to direct way.

272. IPCAA further argued the Commission should not award higher returns to Fortis for an unregulated business risk.[264] The CCA made a similar argument, submitting that the charges are not related to utility service and should, therefore, have no impact on the cost of capital.[265]

273. The Commission finds that the proper course for recovery of costs associated with intermingled service provided to REAs by Fortis is through negotiation and arbitration of integrated operating agreements under the *Roles, Relationships and Responsibilities Regulation*. While Fortis has not enjoyed success recently under that framework, it is the statutorily sanctioned mechanism and is available to Fortis as integrated operating agreements terminate and are renegotiated.

7.6.2 Determination of Commission-approved deemed equity ratio for Apex

274. Apex submitted that its deemed equity ratio should be 400 bps higher than the deemed equity ratio of the average distribution utility because it faces higher business and operational risks than other distribution utilities in Alberta. These risks, it argued, arise because of Apex's small size, geographically dispersed service territory in rural Alberta and gas supply risk.

275. The Commission accepts that these aspects of Apex's size, operations and service territory do create additional risks compared to other distribution companies but not to the extent of an additional 400 bps above the other utilities. The Commission acknowledges that for several years until 2018, it approved an additional 400 bps of equity thickness in excess of the other Alberta utilities to address these risks. The additional equity was intended to meet the business and operational risks that Apex faced. The extra equity thickness provided the utility with greater revenues than would otherwise be the case, in order to compensate for the inability to generate, for example, the cost savings and efficiencies that come from economies of scale that large, mostly urban utilities like ATCO Gas enjoy.

276. However, in the 2018 GCOC decision, the Commission reduced the equity thickness from 41 per cent to 39 per cent because, notwithstanding the additional 400 bps to AltaGas (now Apex), AltaGas's parent[266] (which borrowed money in financial markets and passed it down to AltaGas) was unable to raise debt at an A-range credit rating resulting in customers paying for costs associated with additional equity thickness but without receiving the benefit of lower debt costs.[267] The decision to reduce the equity thickness, the Commission stated, was in keeping with "… the Commission's duty to set a fair return for AltaGas as an element of the just and reasonable rates to be paid by its customers."[268]

277. In the current proceeding, the record shows that even with an extra 400 bps, Apex's current parent, TriSummit, would not achieve an A-rated credit rating because of its relatively small size.[269] Apex argued that TriSummit, which continues to issue public debt instruments to fund Apex's operations and rate base, has a similar business risk profile to its own. For example,

264 Exhibit 27084-X0918, PDF page 20, paragraph 62.
265 Exhibit 27084-X0919, PDF page 26, paragraph 80.
266 Apex was previously known as AltaGas Utilities Inc., and its parent was AltaGas Ltd.
267 Decision 22570-D01-2018, PDF page 176, paragraph 840.
268 Decision 22570-D01-2018, PDF page 176, paragraph 837.
269 Exhibit 27084-X0377, PDF page 20.

80 per cent of TriSummit's assets are regulated utility operations with 95 per cent of its revenue earned from those operations. With this profile, TriSummit has a BBB high credit rating.

278. Apex argued that TriSummit's credit rating and borrowing cost represent an accurate proxy for the market cost of debt for Apex as a stand-alone entity, and that Apex requires an additional 400 bps above the generically deemed equity ratio to achieve the BBB high credit rating of its parent in order to maintain a fair ROE. Additional equity provides a utility with a better opportunity to achieve higher interest coverage ratios while reducing the financial risk to the utility.

279. The Commission finds that the focus in determining Apex's equity thickness should be on the risks identified in 2018 compared to the business risks that it currently faces. In the Commission's view, the risks resulting from Apex's small size, geographically dispersed service areas in mostly rural Alberta and its reliance on third party suppliers have not materially changed since then nor are expected to change in the near future. And there is little, if any, concrete evidence that Apex's financial integrity or its ability to attract investment has been unduly impaired at its current equity thickness of 39 per cent established in 2018.

280. The Commission notes, as interveners have argued, that the fact that the ownership of Apex's parent company has changed twice since the 2018 GCOC decision, most recently in 2020 when pension funds acquired all the outstanding shares of Apex's prior parent, AltaGas Canada Ltd. in a take-private transaction, demonstrates that equity financing is readily available.[270] The Commission also finds that Apex's exposure to the abandonment of third-party laterals that it relies on to supply gas to its distribution network has also remained unchanged since 2018. Apex may well have to purchase or build new laterals itself, but there is little compelling evidence that these risks have increased or will increase, or that a 39 per cent equity thickness undermines Apex's ability respond to these contingencies.

281. In the Etzikom decision[271] referred to by Apex as an example of this risk, the Commission approved construction of a new lateral but denied recovery of these costs under the then PBR framework that governed access to additional capital. Essentially, the Commission found that sufficient funds had been approved in the going-in rates at the beginning of the 2018-2022 PBR term to meet the abandonment of third-party laterals. The Commission stated at paragraph 30:

> The Commission has learned that the distribution utilities have considerable flexibility in dealing with the timing of their capital programs and are capable of accommodating many changes in circumstances without any immediate concerns about service quality and meeting their obligation to serve.

282. In summary, the Commission finds that Apex's risks have not materially changed since 2018 when a 39 per cent equity thickness was awarded to it. Apex has maintained financial integrity and has been able to attract capital on reasonable terms notwithstanding that it enjoyed a higher equity thickness prior to 2018. Further, as TriSummit has a better credit rating than Apex's previous parent, although still not A-rated, the Commission finds that a higher equity

[270] Exhibit 27084-X0926, PDF pages 31-32, paragraph 113, Transcript, Volume 1, pages 249-250.
[271] Decision 25608-D01-2020: AltaGas Utilities Inc., Type 1 Capital Tracker True-Up – Etzikom Lateral Project, Proceeding 25608, October 16, 2020.

thickness is not warranted. The result is that the Commission approves a 39 per cent equity thickness, 200 bps above the generic equity thickness approved for the other utilities.

8 Order

283. It is hereby ordered that:

(1) The final approved generic return on equity for Apex Utilities Inc. AltaLink Management Ltd. and its partners PiikaniLink L.P. and KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is to be set using the methods approved in this decision on an annual basis, beginning in 2024, until determined otherwise by the Commission.

(2) The final approved deemed equity ratio for AltaLink Management Ltd., PiikaniLink L.P., KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is set at 37 per cent. The final approved deemed equity ratio for Apex Utilities Inc. is 39 per cent. These final approved deemed equity ratios are effective January 1, 2024, until determined otherwise by the Commission.

Dated on October 9, 2023.

Alberta Utilities Commission

(original signed by)

Douglas A. Larder, KC
Vice-Chair

(original signed by)

Renée Marx
Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Alberta Direct Connect Consumers Association (ADC)
AltaLink Management Ltd. (AltaLink) Borden Ladner Gervais LLP ScottMadden, Inc.
Apex Utilities Inc. (Apex) MLT Aikins LLP The Brattle Group
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP The Brattle Group
ATCO Gas Bennett Jones LLP The Brattle Group
Capital Power Corporation (CPC) Dentons Canada LLP
Consumers' Coalition of Alberta (CCA)
ENMAX Power Corporation (ENMAX or EPC) Torys LLP Nicole Martin Concentric Energy Advisors, Inc. James Coyne
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden Ladner Gervais LLP ScottMadden, Inc.
FortisAlberta Inc. (Fortis or FAI) Fasken Martineau DuMoulin LLP The Brattle Group
Industrial Power Consumers Association of Alberta (IPCAA) Ackroyd LLP
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP Russ Bell & Associates Inc.

Alberta Utilities Commission

Commission panel
- D.A. Larder, KC, Vice-Chair
- R. Marx, Commission Member
- B. Romaniuk, Acting Commission Member

Commission staff
- L. Berg (Commission counsel)
- A. Marshall (Commission counsel)
- A. Jukov
- D. Mitchell
- M. McJannet
- K. O'Neill
- K. Taylor

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
AltaLink Management Ltd. (AltaLink) and EPCOR Distribution Inc. (EPCOR) J. Liteplo/J. Hulecki	D. D'Ascendis
Apex Utilities Inc. (Apex) R. Jeerakathil	B. Villadsen F. Graves M. Tolleth M. Stock D. Makarenko
ATCO Utilities (ATCO Electric Ltd. and ATCO Gas and Pipelines) T. Myers L. Smith	B. Villadsen F. Graves
FortisAlberta Inc.(Fortis) A. Sears	B. Villadsen F. Graves B. Hendersen
ENMAX Power Corporation (ENMAX) D. Wood/T. Campbell	J. Coyne J. Trogonoski N. Martin
Consumers' Coalition of Alberta (CCA) J.A. Wachowich	J. Thygesen
Industrial Power Consumers Association of Alberta (IPCAA) R. Secord	D. Madsen
Office of the Utilities Consumer Advocate (UCA) R. McCreary/B. Schwanak	R. Bell S. Cleary

Alberta Utilities Commission Commission panel D.A. Larder, KC, Vice-Chair R. Marx, Commission Member B. Romaniuk, Acting Commission Member Commission staff L. Berg (Commission counsel) A. Marshall (Commission counsel) A. Jukov D. Mitchell M. McJannet

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The record of this proceeding includes some monthly data for the base utility bond yield spread but the average daily spread for February 2023 is not available on the record and its calculation requires proprietary data (Bloomberg Series C29530Y). Therefore, the Commission directs the ATCO Utilities, who sponsored the evidence of Dr. Villadsen, to calculate the average utility bond yield spread for the period from February 1 to February 28, 2023 using the calculation steps described in her evidence. The ATCO Utilities are further directed to provide these calculations and the resulting utility bond yield spread value as a post-disposition filing to this proceeding by October 18, 2023. Once confirmed by the Commission, this value will be used as the base utility bond yield spread ($SPRD_{base}$) in the approved formula. .... paragraph 200