Decision **22570-D01-2018**

Alberta Utilities Commission

# 2018 Generic Cost of Capital

## August 2, 2018

**Alberta Utilities Commission**
Decision 22570-D01-2018
2018 Generic Cost of Capital
Proceeding 22570

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## Contents

## List of tables



## List of figures

**Decision 22570-D01-2018**
**2018 Generic Cost of Capital** **Proceeding 22570**

# 1 Introduction

1. This decision sets out the approved return on equity (ROE) for the years 2018, 2019 and 2020 on a final basis. The approved ROE applies uniformly to the utilities listed below:

- AltaGas Utilities Inc. (AltaGas)[1]
- AltaLink Management Ltd. (AltaLink)[2]
- ATCO Electric Ltd. (ATCO Electric)[3]
- ATCO Gas & Pipelines Ltd.[4] [5]
- ENMAX Power Corporation (ENMAX)[6]
- EPCOR Distribution & Transmission Inc. (EPCOR)[7]
- FortisAlberta Inc. (FortisAlberta)[8]
- City of Lethbridge (Lethbridge)[9]
- City of Red Deer (Red Deer)[10]
- TransAlta Corporation (TransAlta)[11]

(collectively, the affected utilities)

2. This decision also sets out the approved deemed equity ratios (also referred to as capital structure) for the affected utilities for 2018, 2019 and 2020 on a final basis.

3. Additionally, this decision considers the two commonly used income tax methodologies, flow-through and future income tax (FIT), and whether the Alberta Utilities Commission will direct the adoption of one standard methodology.

4. The approved final ROE and final deemed equity ratios for 2018, 2019 and 2020 for all of the affected utilities are set out in Table 1 below.

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1 Natural gas distribution.
2 Electricity transmission.
3 Electricity transmission and distribution. Unless otherwise indicated, a reference to ATCO Electric includes both the transmission and distribution operations of this utility.
4 ATCO Gas refers to the utility’s natural gas distribution operations. ATCO Pipelines refers to the utility’s natural gas transmission operations.
5 Collectively, ATCO Electric, ATCO Gas and ATCO Pipelines are referred to as the ATCO Utilities.
6 Electricity transmission and distribution. Unless otherwise indicated, a reference to ENMAX refers to both the transmission and distribution operations of this utility.
7 Electricity transmission and distribution. Unless otherwise indicated, a reference to EPCOR refers to both the transmission and distribution operations of this utility.
8 Electricity distribution.
9 Electricity transmission.
10 Electricity transmission.
11 Electricity transmission assets.

**Table 1. Approved final ROE for 2018, 2019 and 2020, and approved final deemed equity ratios for 2018, 2019 and 2020**

| | 2018 approved | 2019 approved | 2020 approved |
|---|---|---|---|
| | (%) | | |
| **ROE** | 8.5 | 8.5 | 8.5 |
| | | | |
| **Deemed equity ratios** | | | |
| **Electricity and natural gas transmission** | | | |
| AltaLink | 37 | 37 | 37 |
| ATCO Electric | 37 | 37 | 37 |
| ATCO Pipelines | 37 | 37 | 37 |
| ENMAX | 37 | 37 | 37 |
| EPCOR | 37 | 37 | 37 |
| Lethbridge | 37 | 37 | 37 |
| Red Deer | 37 | 37 | 37 |
| TransAlta | 37 | 37 | 37 |
| **Electricity and natural gas distribution** | | | |
| AltaGas | 39 | 39 | 39 |
| ATCO Electric | 37 | 37 | 37 |
| ATCO Gas | 37 | 37 | 37 |
| ENMAX | 37 | 37 | 37 |
| EPCOR | 37 | 37 | 37 |
| FortisAlberta | 37 | 37 | 37 |

5. The approved ROE and deemed equity ratios from this decision do not apply to EPCOR Energy Alberta GP Inc., ENMAX Energy Corporation and Direct Energy Regulated Services because these utilities are regulated pursuant to the *Electric Utilities Act*, *Regulated Rate Option Regulation*[12] and the *Gas Utilities Act Default Gas Supply Regulation*,[13] respectively.

6. The ROE and deemed equity ratios 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 Procedural summary

7. On October 7, 2016, the Commission issued Decision 20622-D01-2016[14] (2016 Generic Cost of Capital (GCOC) decision), which set an approved ROE and deemed equity ratios for 2016 and 2017. With respect to 2018, the Commission stated:

12 Alberta Regulation 262/2005.
13 Alberta Regulation 184/2003.
14 Decision 20622-D01-2016: 2016 Generic Cost of Capital, Proceeding 20622, October 7, 2016.

> 339. The allowed ROE for 2017 of 8.50 per cent awarded in this decision will remain in place on an interim basis for 2018 and for subsequent years until changed by the Commission.[15]
>
> …
>
> 623. The approved deemed equity ratios awarded in this decision will remain in place on an interim basis for 2018 and for subsequent years until changed by the Commission.[16]

8. On April 20, 2017, in Proceeding 20687: Commission-Initiated Generic Proceeding to Address the Income Tax Methodologies Used in Revenue Requirement Calculations for Regulated Utilities in Alberta (Proceeding 20687), the Commission issued correspondence indicating that it was not prepared to prescribe a single income tax methodology without first examining the implications of changing tax methodologies on other components that may affect the setting of rates by the Commission, such as cost of capital.[17] The Commission stated that the best forum to consider these matters was the 2018 GCOC proceeding. Accordingly, the Commission stated that the record of Proceeding 20687 would form part of the record of the 2018 GCOC proceeding.

9. Also on April 20, 2017, the Commission issued a letter initiating the 2018 GCOC proceeding, Proceeding 22570.[18] That letter proposed the scope of issues to be considered in Proceeding 22570 as well as process timelines and provided interested parties with an opportunity to comment.

10. On July 5, 2017, the Commission ruled that it would establish approved ROEs and deemed equity ratios for 2018, 2019 and 2020 in Proceeding 22570. The Commission also addressed the scope of the proceeding and the minimum filing requirements for the utilities. The Commission identified that the scope of Proceeding 22570 would include:

- Whether changes in the approved ROE and deemed equity ratios established in the 2016 GCOC decision are warranted.
- How the Commission should consider the traditional approaches and models used in previous GCOC proceedings for determining an approved ROE and equity ratios.
- The short-term and long-term effects of employing the two commonly used income tax methodologies, flow-through and FIT, on areas such as cost of capital and overall revenue requirement, and how the Commission should consider factors such as differences in the sum of the present discounted value of the revenue requirement and impacts on funds from operations (FFO)/debt in deciding which method should be applied to utilities.[19]
- The issues surrounding income tax methods or treatments, income tax deferral accounts, and performance-based regulation (PBR) implications, as set out by the Commission in its issues list in Proceeding 20687.[20]
- Relevant issues regarding long-term debt.[21]

15 Decision 20622-D01-2016, paragraph 339.
16 Decision 20622-D01-2016, paragraph 623.
17 Exhibit 22570-X0077, paragraph 11.
18 Exhibit 22570-X0078.
19 Exhibit 22570-X0114, paragraph 28.
20 Exhibit 22570-X0114, paragraph 29.

- Matters with respect to municipally owned utilities, specifically how their ownership structure and the relationship between utility ratepayers and municipal taxpayers may affect ROE and deemed equity ratios for these utilities.[22]

11. Each of the affected utilities, except Lethbridge, Red Deer and TransAlta, actively participated in this proceeding. AltaGas and the ATCO Utilities co-sponsored the evidence of Dr. Bente Villadsen, Dr. Paul Carpenter and Mr. Robert Buttke. AltaLink, EPCOR and FortisAlberta co-sponsored the evidence of Mr. Robert Hevert. ENMAX sponsored the evidence of Mr. James Coyne. Additionally, each of AltaGas, AltaLink, ENMAX, EPCOR, FortisAlberta and the ATCO Utilities (collectively, the utilities) filed company-specific evidence, including the minimum filing requirements directed by the Commission.[23]

12. The City of Calgary (Calgary), the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA) (collectively, the interveners) actively participated in the proceeding. Calgary sponsored the evidence of Mr. Hugh Johnson; the CCA submitted the evidence of Mr. Jan Thygesen and Mr. Dustin Madsen; and the UCA sponsored the evidence of Dr. Sean Cleary and Mr. Russ Bell.

13. In addition to the filing of evidence, the Commission's process included information requests (IRs) and responses on the utilities' evidence, and evidence sponsored by the utilities; IRs and responses on evidence sponsored by the interveners; rebuttal evidence filed by the utilities; a two-week oral hearing; and a further process to permit IRs and responses to follow up on outstanding answers to undertakings. The Commission also established a process for simultaneous written argument and reply argument.

14. The Commission considers that the record of this proceeding closed with the filing of reply arguments on May 8, 2018.

15. In reaching the determinations set out in this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party, and the evidence and submissions from Proceeding 20687. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

## 3 Overview of the Commission's approach to setting an approved ROE and approved deemed equity ratios

16. In satisfying the fair return standard, the Commission is required to determine a fair ROE for the affected utilities. In Decision 2009-216[24] (2009 GCOC decision), Decision 2011-474[25]

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21 Exhibit 22570-X0114, paragraph 34.
22 Exhibit 22570-X0114, paragraph 36.
23 A complete list of registered participants is produced in Appendix 1 to this decision.
24 Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571-1, November 12, 2009, paragraphs 77-78.
25 Decision 2011-474: 2011 Generic Cost of Capital Proceeding, Proceeding 833, Application 1606549-1, December 8, 2011, paragraph 2.

(2011 GCOC decision), Decision 2191-D01-2015[26] (2013 GCOC decision) and the 2016 GCOC decision,[27] the Commission established an ROE that uniformly applied to all of the affected utilities and accounted for particular business risks faced by the affected utilities by incorporating any required adjustments into their respective approved deemed equity ratios, either collectively or on an individual basis. The Commission adopted the same approach in this decision.

17. For the purposes of this decision, the Commission's point of departure is the approved ROE and deemed equity ratios established in the 2016 GCOC decision. From this starting point, the Commission has evaluated the evidence and argument in this proceeding to determine whether changes in the approved ROE and deemed equity ratios from the 2016 GCOC decision are warranted.

18. In determining a fair ROE, the Commission begins, in Section 4, with a discussion of the fair return standard. This is followed by a discussion of income tax in Section 5.

19. In Section 6, the Commission evaluates changes in the global economic and Canadian capital market conditions since the conclusion of the 2016 GCOC proceeding. This review is a factor informing the Commission's determination of both a fair approved ROE and deemed equity ratios, as discussed in sections 8 and 9.

20. In Section 7, the Commission considers issues related to the municipally owned utilities, including the availability of the Alberta Capital Financing Authority (ACFA) financing and equity funding riders.

21. In Section 8, the Commission establishes the approved ROE for 2018, 2019 and 2020 on a final basis, after consideration of all the relevant factors, including changes in global economic and Canadian capital market conditions, financial models and the effect of potential regulatory risk factors identified by parties.

22. In Section 9, the Commission establishes the approved deemed equity ratios for 2018, 2019 and 2020, for all of the affected utilities other than AltaGas, after consideration of all the relevant factors, including credit metric analysis, business risk analysis, generic business risks, utility sector business risk analysis and any company specific adjustments. In Section 10, the Commission establishes the approved deemed equity ratio for AltaGas.

23. In Section 11, the Commission addresses other issues raised during the proceeding that are not specifically addressed in other sections.

24. In Section 12 of the decision, the Commission sets out how the approved ROE and deemed equity ratios are to be implemented by the affected utilities.

[26] Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015, paragraph 416.

[27] Decision 20622-D01-2016, paragraph 340.

# 4 Fair return standard

25. All parties agreed that the fair return standard requires consideration of three factors, specifically ‘”comparable investments,” “capital attraction” and “financial integrity.” The CCA suggested that, in addition to these three factors, the fair return should consider ratepayer impacts, while many of the utilities argued that the fair return should only be considered from the perspective of the utility equity investor. Another point of disagreement between the utilities and interveners related to the weight to be placed on comparable investments.

26. The CCA submitted that the Commission should have regard to the impact of any approved ROE and equity thickness on both customers and utilities, and that the fair return should be no more than is absolutely required to maintain safe, reliable and economic service for the foreseeable future.[28] In its reply argument, the CCA argued that the fair return standard does not override the requirement that rates be just and reasonable.[29]

27. EPCOR argued that the fair return factors, assessed from the perspective of an investor, address both investor and customer interests as customers benefit from being served by a functional utility that is able to maintain its financial integrity and attract capital.[30] In its reply argument, EPCOR discussed how an ROE of 25 per cent would doubtlessly satisfy the financial integrity and capital attraction factors, but would be too high to satisfy the comparable investment component, which operates to ensure that the utility and customers pay no more for equity than what the market requires.[31] EPCOR agreed that the just and reasonable standard is a fundamental legal requirement that applies to utility rates generally and to the fair return in particular.[32]

28. The ATCO Utilities and AltaGas suggested that the CCA’s recommendation was an attempt to fabricate a new test for the fair return standard, and referred to several statements from *TransCanada Pipelines Ltd v National Energy Board*, including:

> … While I agree with the appellant that the impact on customers or consumers cannot be a factor in the determination of the cost of equity capital, any resulting increase in tolls may be a relevant factor for the Board to consider in determining the way in which a utility should recover its costs. It may be that an increase is so significant that it would lead to “rate shock” if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process.[33]

29. ENMAX argued that the revenue requirement impact on customers is not a relevant consideration in determining a fair return.[34] Similarly, the ATCO Utilities and AltaGas, in their joint argument, stated that the impact on customer rates is irrelevant when determining the

28 Exhibit 22570-X0888, paragraph 91.
29 Exhibit 22570-X0920, paragraph 223.
30 Exhibit 22570-X0893, paragraph 65.
31 Exhibit 22570-X0915, paragraph 41.
32 Exhibit 22570-X0915, paragraph 34.
33 Exhibit 22570-X0918, paragraph 27.
34 Exhibit 22570-X0896, paragraph 19.

required rate of ROE and that other regulatory mechanisms are available to mitigate impacts on customers.[35]

30. With respect to comparability, in his oral testimony, Mr. Coyne reflected that "I believe that the Commission in 2016 took a leg out from under the stool, or at least shortened it when it put greater reliance on just the credit rating."[36] In his rebuttal evidence, Mr. Coyne provided a figure showing the approved equity returns of Canadian gas and electric distribution utilities that have rates set through a litigated proceeding.[37] In oral testimony, Mr. Coyne admitted that this figure does not adjust for risk.[38] Mr. Coyne described this figure as an objective measure of what comparability looks like and that it is one valid way to consider all three fair return factors.[39] ENMAX argued that if the conclusion is that Alberta utilities are average risk compared to other Canadian utilities, then they should be in the middle of the figure to meet the comparable investments factor.[40]

31. In her evidence, Dr. Villadsen provided a summary of approved ROE and capital structures for regulated Canadian and United States (U.S.) utilities, which she submitted were relevant because investors compare returns across jurisdictions.[41]

32. In argument, EPCOR focused on the comparability or comparable investment component:

> 57. As developed by subsequent Canadian authorities, this aspect of the "fair return" standard has found its most complete expression in the "comparability" or "comparable investment" component of the test. This component has variously been expressed as requiring "(t)hat the investor should be able to obtain a return from his investment such as might alternatively be obtained from other investments of comparable risk and uncertainty," or that a fair return "be comparable to the return available from the application of the invested capital to other enterprises of like risk".[42]

33. EPCOR argued that a return that does not satisfy the comparability standard would not allow a utility to raise new capital or engage in refinancing.[43]

34. Mr. Hevert stated that the required return is a function of the risk and return characteristics of the investment, and not the source of the funds.[44] EPCOR noted that Dr. Cleary confirmed this principle.[45] Mr. Hevert submitted that any notion of a company having a different value depending on how its investors fund their equity investment violates the widely

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35 Exhibit 22570-X0900, paragraph 26.
36 Transcript, Volume 5, page 1002.
37 Exhibit 22570-X0775, PDF page 40.
38 Transcript, Volume 5, page 1005.
39 Transcript, Volume 5, page 1005.
40 Exhibit 22570-X0896, paragraph 47.
41 Exhibit 22570-X0193.01, PDF pages 77-78.
42 Exhibit 22570-X0893, paragraph 57.
43 Exhibit 22570-X0893, paragraph 60.
44 Exhibit 22570-X0153.01, PDF pages 16, 125-126.
45 Transcript, Volume 10, page 2161.

acknowledged economic "law of one price." He added this principal states that in an efficient market, identical assets have the same value.[46]

**Commission findings**

35. In each of the *Public Utilities Act*, the *Gas Utilities Act* and the *Electric Utilities Act*, the fair return is referenced as a component of just and reasonable rates. The *Public Utilities Act* and *Gas Utilities Act* require the Commission, in fixing just and reasonable rates, to determine a rate base upon which it shall fix a fair return.[47] The *Electric Utilities Act* requires the Commission to ensure that a tariff is just and reasonable and provides the owner of an electric utility with a reasonable opportunity to recover a fair return on the equity of shareholders of the electric utility.[48]

36. The interplay between just and reasonable rates and a fair return was described in *Northwestern Utilities Ltd. v Edmonton (City)* as follows:

> The duty of the Board was 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.[49]

37. As reflected in the preceding quotation, determining just and reasonable rates balances the interests of both the utility and its customers. 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.

38. The approach to determining a fair return on the equity component of invested capital in a regulated utility has ordinarily been referred to as the fair return standard.[50] The Commission has addressed the fair return standard in previous GCOC decisions, with Decision 2009-216[51] providing a thorough discussion of the underlying statutory framework and relevant case law. As discussed in Decision 2009-216, the Commission and its predecessors have accepted and considered the following three factors when setting a fair return: "comparable investments," "capital attraction" and "financial integrity." The Commission considers these factors to be well established and continues to be satisfied that the fair return standard is met when the return satisfies these three factors, while also understanding that this is a component of just and reasonable rates.

39. The Commission also does not consider that simply matching the ROE and deemed equity ratios awarded by other regulators satisfies the fair return standard, nor does it establish just and reasonable rates. The Commission remains of the view that seeking to match approved returns in other jurisdictions provides an outcome that is inherently circular. The objective of the

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46 Exhibit 22570-X0153.01, PDF page 126.
47 *Public Utilities Act*, RSA 2000, c P-4, s 90(1); *Gas Utilities Act*, RSA 2000, c G-5, s 37(1).
48 *Electric Utilities Act*, SA 2003, c E-5.1, s 121(2)(a), 122(1)(a)(iv).
49 *Northwestern Utilities Ltd v Edmonton (City)*, 1929 CarswellAlta 114, paragraph 18, [1929] 2 DLR 4, [1929] SCR 186.
50 Decision 2009-216, paragraph 87.
51 Decision 2009-216, Section 2.

GCOC is to consider the market expectation for the utilities raising capital and providing utility service in Alberta, not simply mimicking the returns awarded by other regulators.

40. In addition, there is insufficient evidence to conclude that utilities in other Canadian and U.S. jurisdictions are comparable and face the same risks as the affected utilities. The determination of a "comparable" return requires the Commission to apply its judgment in assessing the specific cost of capital for the utilities based on the evidence presented and in the absence of any utility under the Commission's jurisdiction issuing equity directly to investors.

41. The Commission acknowledges Mr. Hevert's view that "The opportunity cost concept applies regardless of the source of the funding." and that the nature of the investor does not necessarily impact the expected risk-adjusted return of an investment.[52] However, the Commission operates within its legislated mandate, and does not take this principle to mean that the owner or investor in the regulated utility must be disregarded in all contexts. Where the source of funds is likely to result in harm to customers of a regulated utility, the Commission may consider this.

42. For example, in circumstances where the Commission is tasked with approving the sale of a utility to another investor, the Commission has traditionally applied a no-harm test that considers, amongst other things, the impact of such a sale on customer rates and the impact on the financial profile of the utility for the purposes of attracting capital.[53]

43. The Commission may deny a sale or other transaction under sections 101 and 102 of the *Public Utilities Act* if the Commission determines that the transaction is likely to result in harm to customers in terms of the rates paid for service or the reliability of that service.

44. In applying for approval of a multi-step transaction whereby MidAmerican (Alberta) Canada Holdings Corporation (MC Alberta), a wholly owned subsidiary of Berkshire Hathaway Energy Company (BHE), replaced SNC as the owner of the entities that own and operate AltaLink, L.P.'s (ALP) transmission assets and business, MC Alberta cited the following passage made by the Alberta Energy and Utilities Board (the Board), the Commission's predecessor:

> The Board notes that, with respect to these types of applications, any potential benefits are generally intangible and harder to quantify. The Board notes that one persuasive factor in any sale is that a company that wants to be in the business is replacing one that wishes to exit the business.[54]

45. In its decision approving the above-noted transaction, the Commission noted:

> 116. In addition, MC Alberta noted that in its credit rating analysis, S&P took specific note of the fact that utility ownership is a core business of BHE, and also suggested that the fact that AILP [AltaLink Investments, L.P.] would be of more strategic importance to

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52 Exhibit 22570-X0153.01, PDF page 16.

53 Decision 2014-326: AltaLink Investment Management Ltd. and SNC Lavalin Transmission Ltd. et al., Proposed Sale of AltaLink, L.P. Transmission Assets and Business to MidAmerican (Alberta) Canada Holdings Corporation, Proceeding 3250, Applications 1610595-1, 1610596-1, 1610597-1, November 28, 2014, paragraphs 107-108.

54 Decision 2014-326, paragraph 115.

> BHE, as compared to the nonstrategic status of ALP to SNC-Lavalin could affect credit ratings after the close of the proposed transaction.
>
> 117. MC Alberta further noted that the Commission's predecessor had ascribed a benefit to customers from the acquisition of a utility by an owner with "access to extensive experience … through its affiliated companies" and argued that the fact that BHE affiliated companies have extensive experience in the electric utility industry is a relevant consideration for the Commission.[55]

46. The Commission recognized in Decision 2014-326 that the source of funds / financial strength of the owner is a consideration in determining whether a transaction satisfies the "no harm" test, and that any impact on credit ratings may have a corresponding impact on rates.[56] The Commission found that the willingness, experience and financial strength of the proposed owner of AltaLink was a positive factor.

## 5 Income taxes

47. As noted in Section 2, the scope of this proceeding includes various issues originally identified in the Commission-initiated generic proceeding on income taxes (Proceeding 20687). In a letter dated April 20, 2017,[57] the Commission decided that the income tax issues should be addressed as part of the 2018 GCOC proceeding. The Commission therefore closed Proceeding 20687 and informed parties that the record of Proceeding 20687[58] would form part of the record of this GCOC proceeding.

48. The scope of Proceeding 20687 included a consideration of income tax methods, income tax deferral accounts and PBR implications. The scope was expanded in this GCOC proceeding to include a consideration of the effects of employing flow-through and FIT on areas such as cost of capital and overall revenue requirement.[59]

49. The Commission addresses the following issues regarding income tax in the sections that follow:

- Income tax methods, including whether all the utilities should adopt one standard method.
- Claiming maximum allowable income tax deductions when forecasting income tax expense.
- The CCA's recommendation regarding reporting future income tax liabilities.
- Use of deferral accounts for income tax.
- PBR implications associated with income tax.

55 Decision 2014-326, paragraphs 116-117.
56 Decision 2014-326, paragraphs 122-123.
57 Exhibit 22570-X0077.
58 Exhibits 22570-X0002 to 22570-X0077 comprise the record of Proceeding 20687.
59 Exhibit 22570-X0078, paragraph 3.

50. AltaGas, AltaLink, the ATCO Utilities and FortisAlberta (the taxable utilities) are subject to income tax, although FortisAlberta is currently in a non-tax-paying position as a result of maximizing allowable deductions for income tax.[60] As municipally owned utilities, EPCOR, ENMAX, Lethbridge and Red Deer are exempt from paying income taxes.[61]

### 5.1 Standardization of income tax methodology

51. For all taxable utilities, the currently approved method for determining the forecast income taxes to be included in revenue requirement is the flow-through method, with one exception. While the provincial income taxes for ATCO Electric Transmission are determined using the flow-through method, the federal income taxes are determined using the FIT method. As described by the ATCO Utilities, the Commission approved the use of the FIT method for federal income taxes for ATCO Electric Transmission to support its credit metrics at sufficient levels to target credit ratings in the A-range.[62]

52. In this proceeding, parties focussed on two common income tax methods: the flow-through method and the FIT method.

53. The flow-through method is analogous to the cash basis of accounting. When using the flow-through method, the forecast income tax is calculated by multiplying the forecast income tax rates (federal and provincial) by the respective federal and provincial taxable income. In determining taxable income, non-cash expenses such as depreciation are not deductible. Instead of depreciation, the taxing authorities permit a deduction called capital cost allowance. The depreciation rates approved by the Commission are generally lower than the capital cost allowance rates approved by the federal and provincial taxing authorities. Consequently, during periods when the monetary value of the capital asset additions of a utility is quite large, the capital cost allowance deduction is much greater than the non-deductible depreciation expense.

54. In addition, income tax deductions are available for items such as overhead costs associated with capital assets. While these overhead costs are capitalized and recovered from customers over the life of the capital asset for utility ratemaking purposes, the costs are fully deductible for income tax purposes in the year they are incurred.

55. As a result of differences in depreciation and capital cost allowance and the ability to immediately deduct certain costs for income tax purposes, taxable income and income taxes are lower in periods when the utility has capital asset additions of significant monetary value.

56. The flow-through method permits the utility to take advantage of all available income tax deductions. As discussed above, this helps reduce income taxes during periods of significant rate base additions. However, the flow-through method does not include any recognition for future periods when the capital cost allowance pools may be diminished. Any diminished capital cost allowance pools in future periods would result in increased income taxes in those future periods, all else being equal.

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60 Exhibit 22570-X0039, paragraph 12

61 As noted in Exhibit 22570-X0002, paragraph 3: "… a municipal corporation that earns more than 90 per cent of its income within the geographical boundaries of the municipality is exempt from paying income taxes pursuant to the *Income Tax Act* …"

62 Exhibit 22570-X0900, paragraph 228.

57. The FIT method is analogous to the accrual basis of accounting and consists of two components. The first component is the cash income taxes. The cash component, being the amount that would have to be paid to the taxing authorities, is determined using the flow-through method described above. The second component is the future income taxes. The future income taxes are determined by accounting for all the differences between the non-cash expenses and the income tax deductions. Because these differences are accounted for, the FIT method recognizes the liability for increased income taxes in future periods, all else being equal. Any FIT balances are also adjusted for changes in future income tax rates.[63]

58. All of the taxable utilities have had substantial capital asset additions over the last number of years. Consequently, the income taxes calculated for the taxable utilities using the flow-through method are lower than if the FIT method had been used. FortisAlberta submitted that its continued use of the flow-through method is the most advantageous approach for both customers and FortisAlberta.[64] AltaGas,[65] AltaLink[66] and the ATCO Utilities[67] all submitted that the flow-through method should be used absent any special circumstances. Among the special circumstances identified by the ATCO Utilities were credit metric support during periods of large capital growth, a change in credit metric targets, and consistency with accounting standards.[68] AltaLink mentioned the circumstance of imminent aggregate cross-over, which would occur when the available income tax deductions are less than the non-cash deductions.[69] AltaGas indicated that the flow-through method is commonly used by other regulated utilities in Canada.[70]

59. Among the interveners, Calgary and the UCA supported the use of the flow-through method. Calgary indicated this is consistent with decisions of the National Energy Board and the Ontario Energy Board, is beneficial to the customers of the utilities and reduces risk to the utilities.[71] The UCA supported the position of Mr. Bell that the flow-through method be used, absent any special circumstances such as imminent cross-over or the downgrade of credit metrics.[72]

60. The only party opposed to the continued use of the flow-through method was the CCA. Based on the evidence of Mr. Madsen, the CCA submitted that the FIT method be approved as the preferred method for accounting for income taxes.[73] However, it cautioned that the assessment of whether it is appropriate for a utility to immediately transition to FIT must be done on a utility-by-utility basis.[74]

63 Exhibit 22570-X0044, PDF page 12.
64 Exhibit 22570-X0228, paragraph 8.
65 Exhibit 22570-X0127, paragraphs 16 and 21.
66 Exhibit 22570-X0141, paragraph 53.
67 Exhibit 22570-X0171, paragraph 4.
68 Exhibit 22570-X0171, paragraph 6..
69 Exhibit 22570-X0141, paragraph 53.
70 Exhibit 22570-X0127, paragraph 9.
71 Exhibit 22570-X0903, paragraph 56.
72 Exhibit 22570-X0897.01, paragraph 359. Exhibit 22570-X0050, paragraph 13.
73 Exhibit 22570-X0888, paragraph 469.
74 Exhibit 22570-X0888, paragraph 393.

### 5.1.1 Relevant factors in assessing the suitability of an income tax method

61. Mr. Madsen based his recommendation for the adoption of the FIT method on four principles: intergenerational equity, matching, cost causation and consistency.

62. AltaGas submitted that the factors considered by the Commission in previous proceedings continue to be relevant. Both AltaGas and AltaLink referred to previous considerations, such as potential rate shock, rate stabilization, intergenerational equity, regulatory burden, consistency with accounting standards, impact on credit metrics and the treatment of any future income tax costs as no-cost capital.[75] AltaLink added the stand-alone principle as an overarching principle, which results in determining regulatory income tax on a deemed corporation basis.[76]

63. The Commission also received evidence about differences in the sum of the present discounted value of the revenue requirement and the impacts on FFO/debt, in deciding which income tax method should be applied to the utilities.

#### Intergenerational equity

64. Mr. Madsen focused on the timing differences for income tax associated with overhead costs and salvage costs, both of which are associated with capital assets. Mr. Madsen explained that an income tax deduction is available for the full amount of the overhead costs in the year they are incurred, whereas for ratemaking purposes, the costs are recovered over the life of the capital asset. For ratemaking purposes, salvage costs are also collected over the life of the capital asset, but for income tax purposes, the costs are not deductible until the year they are incurred, which is the last year of the capital asset's life. Under the flow-through method, these timing differences persist, and Mr. Madsen commented that these timing differences can be significant. He further submitted that under the FIT method, these timing differences are accounted for, and because of this, the income tax benefit of the overhead costs and the salvage costs are allocated to all customers over the life of the capital asset.[77]

65. AltaGas suggested that the findings of the Commission's predecessor, the Public Utilities Board, in Report E79079,[78] conflict with Mr. Madsen's argument about intergenerational equity. It referred to the findings of the Public Utilities Board that the FIT method provides for a potential liability rather than a real liability, with much uncertainty surrounding the probability of payment of the future income tax component.[79] AltaGas submitted that the adoption of the FIT method would result in a higher proportion of a new capital asset's costs being shifted to the earlier years of its life.[80] It stated that any assessment of intergenerational equity needs to be done on the overall revenue requirement, not just the income tax component.[81]

66. The ATCO Utilities submitted that if utilities move from the flow-through method to the FIT method, the resulting collection of any unfunded FIT liability will contribute to

[75] Exhibit 22570-X0041, paragraph 10.
[76] Exhibit 22570-X0043, paragraphs 10-13.
[77] Exhibit 22570-X0557, paragraphs 37-42.
[78] Report E79079: The Income Tax Component of the Utility Revenue Requirement for Alberta Utilities, August 1, 1979.
[79] Exhibit 22570-X0783, paragraph 14.
[80] Exhibit 22570-X0783, paragraph 18.
[81] Exhibit 22570-X0783, paragraph 18.

intergenerational inequity, because the unfunded FIT liability has accumulated over many decades.[82] The ATCO Utilities contended that any purported advantages of the FIT method in mitigating intergenerational equity concerns are not sufficient to justify a requirement that the utilities all convert to the FIT method.[83]

67. Dr. Villadsen commented that Mr. Madsen's focus on intergenerational equity is very narrow, because he examines what happens during two specific years of a capital asset's life, the first year and the last year. She submitted this focus is less relevant because of the utilities' continuous ongoing investment in capital assets.[84]

68. AltaLink suggested that under the FIT method, current ratepayers would be paying higher rates that include an income tax component that may not be payable at some uncertain future time.[85]

### Matching of costs and revenues

69. Mr. Madsen provided the following explanation for why the flow-through method does not adhere to the matching of costs and revenues principle:

> A. MR. MADSEN: And to be clear, though, I don't agree necessarily that there is a better matching from a regulatory perspective. As my evidence has stated, the Commission allows and approves the collection of numerous costs, depreciation, salvage, overheads, a number of costs over the life of the assets from a regulatory perspective, and yet the income taxes, from a regulatory perspective, are not collected on the same basis; i.e., the income taxes costs are not matching the revenues that drive them.[86]

### Cost causation and consistency

70. Mr. Madsen indicated that from an accounting perspective, the accrual method is commonly accepted. He added that for regulatory purposes, the cost causation principle as well as intergenerational equity drive the collection of certain items such as depreciation and salvage over the life of a capital asset, as opposed to collecting the entire cost in one year. Mr. Madsen submitted that the income tax impacts associated with items such as depreciation, salvage and overhead costs should likewise be reflected in revenue requirement over the life of a capital asset. He submitted that this would also promote the consistency principle.[87]

71. The CCA commented that the flow-through method requires customers to simply pay for a cost when there is a cash outflow. It submitted that a cash outflow may not demonstrate a causal link to the customers who drove that cost, especially when the cash outflow is determined by the *Income Tax Act*, which is not intended to reflect sound ratemaking principles.[88]

72. AltaLink contended that there are differences between depreciation and future income taxes. It submitted that while depreciation is based on the actual costs the utility pays for its

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[82] Exhibit 22570-X0746, paragraph 12.
[83] Exhibit 22570-X0746, paragraph 13.
[84] Exhibit 22570-X0767.01, A125.
[85] Exhibit 22570-X0043, paragraph 36.
[86] Transcript, Volume 7, page 1380.
[87] Exhibit 22570-X0557, paragraphs 43-45.
[88] Exhibit 22570-X0888, paragraph 434.

capital assets, future income taxes are a non-cash expense with uncertainty regarding their timing and amount.[89]

73. Dr. Villadsen stated that regardless of which income tax method is used, customers pay more in the early years of a capital asset's life for the recovery of capital, and she suggested this is so even though the service provided by the capital asset is not necessarily more valuable to customers in those early years.[90]

74. The CCA described certain factors that may cause larger-use customers to decide they no longer want to receive service from their utility. The CCA expressed its concern that if these larger-use customers no longer receive service from their utility, the residential customers will be left with the burden of increased costs, including future income taxes. Emphasizing the cost causation principle, the CCA submitted that under the flow-through method, these larger-use customers will not have paid for their share of future income taxes, even though they triggered the costs. The CCA submitted that the continued use of the flow-through method does not result in a fair allocation of costs among ratepayers.[91] AltaLink countered that the use of the FIT method, with its resulting increases in customer rates, will exacerbate the risk of larger-use customers no longer wanting to receive utility service from their utility.[92] Mr. Bell expressed a similar view in response to questioning from Commission Member Lyttle at the hearing.[93]

**Impact on rates**

75. AltaLink indicated that a switch from the flow-through method to the FIT method would result in significant increases in customer rates.[94] AltaLink submitted that the impact on customer rates should be a consideration when determining the income tax method, especially in times of a downturn in the economy, when rate relief is most needed.[95]

76. AltaGas submitted that if it had to switch to the FIT method, and its total unfunded FIT liability had to be collected from customers, it would likely result in some degree of rate shock, and create an administrative burden to track and account for the change in the income tax method.[96]

77. Mr. Madsen stated that the Commission has significant latitude to determine how the FIT liability can be funded by customers. He indicated the liability does not need to be fully funded in a short period of time, and the period of time over which the liability should be funded would be specific to each utility and where that utility is within the overall life of its capital assets. Another option noted by Mr. Madsen, though not a preferred option, would be to ignore the accumulated FIT liability on transition, and monitor it on a go-forward basis to assess whether collection in a future period would be possible.[97]

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89 Exhibit 22570-X0738, paragraph 89.
90 Exhibit 22570-0767.01, A122 and A124.
91 Exhibit 22570-X0888, paragraphs 407, 409, 413.
92 Exhibit 22570-X0058, paragraphs 33-34.
93 Transcript, Volume 10, page 2171.
94 Exhibit 22570-X0043, paragraph 34.
95 Exhibit 22570-X0043, paragraph 18.
96 Exhibit 22570-X0041, paragraph 12.
97 Exhibit 22570-X0557, paragraphs 70-75.

78. AltaLink commented that the collection of future income taxes, and their treatment as no-cost capital, introduces refinancing risk in future years when the accumulated FIT liability is drawn down and the utility has to replace it with debt and equity, at rates that may be greater than the period over which the future income taxes were collected.[98]

**Consideration of the sum of the present discounted value of the revenue requirement in determining an income tax method**

79. Dr. Villadsen undertook an analysis that considered a simple illustrative model, using a set of representative input parameters, in order to evaluate the effects of applying the flow-through method and the FIT method to a hypothetical regulated utility.[99] Based on her analysis, Dr. Villadsen concluded that when measured purely in terms of the sum of the present value of the revenue requirement over the full economic life cycle of a utility investment, there is no clear advantage for customers or the utilities from either the flow-through method or the FIT method.[100]

80. AltaLink submitted that present value or discounted cash flow analysis is not the best factor to consider when deciding on an income tax method. AltaLink suggested that larger industrial or commercial customers, who typically have higher discount rates than a utility, prefer to keep their funds to invest in their business, rather than involuntarily paying future income taxes.[101]

**Impact on credit metrics**

81. The CCA submitted that when deciding upon an income tax method, the Commission should not ignore the ability of the FIT method to improve a utility's credit metrics.[102]

82. Dr. Villadsen agreed that the FIT method will provide a utility with greater cash flow early in the life of a capital asset, which can provide support for credit metrics such as FFO/debt. However, she cautioned that later in the life of the capital asset, the situation is reversed. Dr. Villadsen submitted that implementing the FIT method should be viewed as a long-term commitment, and therefore it is important to consider both the short-term and long-term consequences for credit quality, when determining an income tax method.[103]

**Commission findings**

83. The scope of the Commission's generic proceeding on income taxes included an exploration of whether one income tax methodology should be applied uniformly to all utilities, or whether different methodologies should be used under different circumstances.

84. The Commission agrees that transition to the FIT method will reveal significant FIT liabilities.[104] The estimated balance at December 31, 2017, of the unfunded FIT liabilities is

[98] Exhibit 22570-X0043, paragraph 46.
[99] Exhibit 22570-X0170, A4.
[100] Exhibit 22570-X0170, A3.
[101] Exhibit 22570-X0141, paragraph 55.
[102] Exhibit 22570-X0888, paragraph 473.
[103] Exhibit 22570-X0170, A19.
[104] See, for example, Exhibit 22570-X0557, A70.

approximately $1.4 billion.[105] This balance would have to be grossed up for current income taxes in determining rates. Using the current statutory income tax rate of 27 per cent, the result would be approximately $1.9 billion.

85. In considering this issue, the Commission must be cognizant of revenue requirement effects and the resulting impact on rates. Collection of approximately $1.9 billion to fund the estimated total FIT liabilities at December 31, 2017, and the additional estimated total increase in annual revenue requirements of approximately $200 million associated with adopting FIT, has to be considered when deciding whether all utilities should adopt the FIT method. The Commission must also consider the other relevant factors identified, including intergenerational equity, matching, cost causation and consistency, and impact on credit metrics.

86. Mr. Madsen's assessment of intergenerational equity focused on the timing differences associated with overhead costs and salvage costs. The Commission agrees with Dr. Villadsen's comments that Mr. Madsen's focus in this area was very narrow, because he focused on the income tax deductibility of overhead costs in the first year of an asset, and the deductibility of salvage costs in the last year.

87. The Commission considers that the two examples provided by Mr. Madsen are representative of intergenerational issues, when considered in isolation. Under the flow-through method, if a person is not a customer in the year a capital asset is added, but becomes a customer in the year after the capital asset has been added, the customer will not have received the benefit of the deduction of the overhead cost in the first year. Similarly, if a person is a customer in the year the capital asset is added, and remains a customer until the year before the capital asset is retired and salvage costs are incurred and deducted for income tax, that customer does not receive the benefit of that income tax deduction.

88. However, the Commission agrees with Dr. Villadsen that these examples ignore the continuous ongoing investment in capital assets that the utilities make. Consequently, in Mr. Madsen's example, the person who becomes a customer in the year after a capital asset is added, will benefit from the deduction of the overhead costs of the capital asset that is added in the year that person becomes a customer. Mr. Madsen's second example, relating to salvage costs, ignores the consideration that the customer would have benefitted from the deduction of salvage costs that were paid out while that person was a customer.

89. The Commission finds that the issue of intergenerational equity with respect to income tax is more complex than was represented by Mr. Madsen's examples. One example observed by Dr. Villadsen, with respect to the income tax reform in the U.S. in December 2017, highlighted the potential for intergenerational equity implications. Dr. Villadsen indicated that most U.S. utilities recover income taxes on a method that is similar to FIT. She noted that because of the reduction in the U.S. federal income tax rate, the FIT liabilities for these U.S. companies will be reduced, and most of these utilities now have over-collected their FIT.[106] The Commission considers this situation, which is specific to the FIT method, also raises intergenerational equity concerns.

105 Exhibit 22570-0746, Table 1.
106 Exhibit 22570-X0767.01, A147-A148.

90. The Commission finds that the submissions of Mr. Madsen with regard to the intergenerational issues raised by the flow-through method fail to offer convincing support for the abandonment of this method and the adoption of the FIT method for all utilities, especially in light of the fact that the FIT method has potential to create its own intergenerational issues.

91. Mr. Madsen submitted that the flow-though method does not adhere to the matching of costs and revenues. He indicated that the Commission allows and approves the collection of numerous costs such as depreciation, salvage and overheads over the life of the assets from a regulatory perspective, yet it does not do so for income taxes. He stated that the income tax costs are not matching the revenues that drive them. The Commission finds that Mr. Madsen's analysis does not account for the fact that there are differences between the utilities with respect to items such as depreciation and salvage. For example, EPCOR recovers salvage costs over the life of the assets that are in place subsequent to the retirement of the asset, whereas the other utilities generally recover salvage costs during the life of the original asset.

92. The Commission considers that the actual income taxes paid to the taxation authorities are valid income tax costs for regulatory ratemaking purposes, and these costs are matched to the revenues that drive them. While the liability for future income taxes exists, the measurement of that liability, as reflected on a utility's balance sheet, is done at a certain point in time, based on a number of assumptions. It is assumed that no other capital assets will be added and that future depreciation rates, capital cost allowance rates and statutory income tax rates, among others, will remain constant. These assumptions and correspondingly, the FIT liability, change from year to year. This adds much uncertainty as to whether the FIT expense is an accurate representation of the actual income taxes the utility will pay to the taxation authorities in subsequent years. The situation where U.S. utilities operating under FIT recently experienced a reduction in the statutory tax rate highlights this point. The Commission considers this uncertainty supports arguments against the FIT method being adopted as the standard income tax method for revenue requirement purposes.

93. Mr. Madsen commented that in order to promote the consistency principle, depreciation, salvage and overhead costs are collected over the life of a capital asset, and so should the income tax impacts associated with these items. For regulatory purposes, overhead costs form part of the cost of a capital asset, and are therefore recovered through depreciation. Salvage costs are linked to the cost of retiring a capital asset. The Commission considers that, even in isolation, the actual income tax associated with a capital asset over its life cannot be determined without a number of assumptions, as the Commission has commented on above. When this is combined with the fact that the utilities are adding capital assets on an annual basis, this income tax determination is made even more difficult.

94. A depreciation rate is applied to a class of capital assets in order to ensure that the cost of the capital assets is recovered. The cost of the capital assets is known. Income taxes, as their description suggests, are associated with income, and the income over the life of any particular capital asset is unknown. The reasons for collecting depreciation over the life of a capital asset for regulatory purposes are well known and are grounded in the collection of the original cost of the capital asset. The collection of income taxes is not limited to the original cost of any particular capital asset, but instead involves additional factors such as income tax rates and the availability of income tax deductions. In consideration of all of the above, the Commission finds that there is no need for consistent treatment between the collection of depreciation, salvage costs and overheads, and the uncertain income tax impacts associated with them.

95. For all these reasons, the Commission finds that Mr. Madsen's recommendation for the use of the FIT method is not supported. Given this finding, and the Commission's understanding that the adoption of the FIT method would result in significant cost implications for customers, the Commission will not require every utility to uniformly adopt the FIT method.
The Commission finds that the use of the flow-through method is acceptable, and should continue to be used as the default method.

96. The Commission does not consider that the foregoing should prevent a utility from applying to adopt the FIT method in a future rate-related proceeding. The onus will be on the applicant proposing FIT in a future rate-related proceeding to satisfy the Commission that the specific circumstances warrant a change to the FIT method.

## 5.2 Claiming maximum allowable income tax deductions when forecasting income tax expense

97. One issue with regard to determining cash income taxes is whether the utility should claim the maximum allowable deductions for income tax purposes, even if it results in taxable income less than zero. The CCA endorsed AltaLink's policy of not triggering taxable income of less than zero for forecast purposes, and it submitted that all the utilities should follow this practice.[107]

98. AltaGas submitted that any requirement to maximize income tax deductions and carry-back income tax losses, instead of carrying them forward, will result in lost savings in the situation where income tax rates are increasing.[108] It indicated that income tax losses, when carried forward, expire after 20 years, whereas discretionary deductions such as the claiming of capital cost allowance, can be carried forward indefinitely.[109] AltaGas submitted the utilities should be given flexibility to claim the proper level of discretionary income tax deductions given the circumstances as this would give them the best opportunity to manage their income tax portfolios and realize available cost savings.[110]

### Commission findings

99. The Commission finds that because of the finite life of income tax loss carryforwards, as opposed to the indefinite life of deductions such as capital cost allowance, the conservative practice would be for utilities not to forecast income tax losses, but instead, forecast the use of discretionary deductions such as capital cost allowance in order to reduce forecast taxable income to zero. Accordingly, the Commission directs the utilities, when forecasting income taxes, to only claim allowable deductions that will reduce the taxable income to a maximum of zero.

## 5.3 Reporting of future income tax liabilities

100. Mr. Madsen recommended that the Commission require the utilities to quantify their accumulated and unreported FIT liability under International Financial Reporting Standards each year, and report this information each year as part of their Rule 005: *Annual Reporting Requirements of Financial and Operational Results*. He also recommended that each utility

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107 Exhibit 22570-X0557, paragraphs 100-103.
108 Exhibit 22570-X0041, paragraph 17.
109 Exhibit 22570-X0041, paragraph 20.
110 Exhibit 22570-X0127, paragraph 28.

should propose a method to fund the FIT liability as part of their next cost-of-service application or PBR filing.[111] Mr. Madsen and the CCA submitted that this information should be reported, even if the Commission continues to approve the use of the flow-through method.[112]

101. With respect to the CCA's recommendation for utilities to report their unfunded FIT liability, AltaGas noted that this information is currently reported as part of its annual audited financial statements.[113] Both AltaGas and the ATCO Utilities submitted that any amendments to Rule 005 are outside the scope of this GCOC proceeding. They indicated that reporting the unfunded FIT liability is not warranted as part of Rule 005, because this liability has no bearing on the utility's financial performance. AltaGas and the ATCO Utilities proposed that the CCA's recommendation be dismissed.[114]

### Commission findings

102. The Commission agrees with AltaGas and the ATCO Utilities that reporting the unfunded FIT liability would have no bearing on their financial performance. However, given the magnitude of the unfunded FIT balances that were forecast as of December 31, 2017, and the Commission's consideration that the calculation and reporting of this balance on an annual basis would not require a significant amount of effort, the Commission directs the ATCO Utilities, FortisAlberta, AltaGas and AltaLink to include their unfunded FIT liability balance each year as part of their Rule 005 reports, beginning with the Rule 005 report for 2018, that will be submitted in 2019. The information provided should consist of the unfunded FIT liability for the year being reported, as well as the previous year, and the resulting difference. This information may assist the Commission in assessing the level of potential credit metric relief that may be available if a utility were to apply to adopt the FIT method.

## 5.4 Income tax deferral accounts

### Criteria for establishing deferral accounts

103. The ATCO Utilities recommended that any deferral accounts for income taxes be established in accordance with the criteria the Commission has previously applied. The ATCO Utilities described these criteria as being (1) the materiality of the forecast amount; (2) uncertainty regarding the accuracy of the forecast amount; (3) uncertainty regarding the ability of the utility to forecast the amount; (4) whether or not the factors affecting the forecast are typically beyond the utility's control; and (5) whether or not the utility is typically at risk with respect to the forecast amount.[115]

104. Mr. Bell recommended that the use of deferral accounts be minimized. He submitted that deferral accounts transfer risk from the utility to customers. Mr. Bell stated that a deferral account should only be allowed if it satisfies the criteria established by the Commission for Y factor treatment. These criteria include (1) the amounts are attributable to events outside management's control; (2) have significant influence on the operation of the company; (3) do not have a significant influence on the inflation factor (I factor) in the PBR formula; (4) have been

[111] Exhibit 22570-X0557, paragraph 76.
[112] Exhibit 22570-X0557, paragraph 23. Exhibit 22570-X0888, paragraph 402.
[113] Exhibit 22570-X0783, paragraph 20.
[114] Exhibit 22570-X0918, paragraph 270.
[115] Exhibit 22570-X0044, paragraph 11.

prudently incurred; and (5) are of a recurring nature with the potential for a high level of variability.[116]

**Deferral account for statutory income tax rates and capital cost allowance rates**

105. AltaLink submitted that a deferral account should be used for statutory income tax rate changes as well as changes to capital cost allowance rates.[117] It added that changes in these rates could be material and are beyond the control of a utility.[118] AltaGas and Mr. Madsen agreed with establishing deferral accounts for changes in statutory income tax rates and changes in capital cost allowance rates.[119] Mr. Bell commented that changes in statutory income tax rates clearly qualify for deferral account treatment.[120]

106. In accordance with the criteria for deferral accounts they put forward, the ATCO Utilities suggested that a deferral account for changes in statutory income tax rates be established.[121]

107. Mr. Madsen and AltaGas commented on the Commission's finding in Decision 2012-237[122] that changes in statutory income tax rates impact the entire economy and should be captured by the I factor for the PBR utilities. Mr. Madsen and AltaGas stated that there is a lag in the impact of a change in the statutory income tax rate on the I factor.[123] AltaGas contended that there is no direct causal link between changes in statutory income tax rates and inflation.[124] Mr. Madsen submitted that changes such as increasing revenue requirements and income taxes, the potential for changes in governments and the significant income tax changes implemented in recent years are outside the control of the utilities, and this supports the use of deferral accounts for changes in statutory income tax rates.[125]

**Deferral account for temporary differences and income tax reassessments**

108. Mr. Madsen supported the continued inclusion of temporary differences for income tax within the currently established direct assigned capital deferral accounts for the transmission utilities that operate under cost of service.[126] Mr. Madsen suggested that elective income tax planning strategies, such as the use of rolling starts for lengthy projects, should be the subject of a deferral account, unless the Commission can incorporate the effects of such income tax planning strategies in a way that allows customers to share in the future benefits.[127]

109. Mr. Madsen submitted that in the case of utilities that have a history of poor forecasting accuracy with regard to temporary income tax differences that are not subject to an existing

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116 Exhibit 22570-X0559, A25.
117 Exhibit 22570-X0043, paragraph 5.
118 Exhibit 22570-X0043, paragraph 20.
119 Exhibit 22570-X0783, paragraph 35. Exhibit 22570-X0557, paragraph 85.
120 Exhibit 22570-X0559, A25.
121 Exhibit 22570-X0044, paragraph 12. In Exhibit 22570-X0171, paragraph 21, the ATCO Utilities provided more details about how any changes in statutory income tax rates would be addressed as part of an adjustment to revenue.
122 Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.
123 Exhibit 22570-X0557, paragraph 86. Exhibit 22570-X0041, paragraph 26.
124 Exhibit 22570-X0041, paragraph 26.
125 Exhibit 22570-X0557, paragraph 86.
126 Exhibit 22570-X0557, paragraph 90.
127 Exhibit 22570-X0557, paragraph 106.

deferral account, the Commission should determine whether a reserve or deferral account is necessary. He indicated that a deferral account should be utilized until such time as the utility can demonstrate a clear ability to properly forecast its income tax expense. Mr. Madsen suggested the Commission make these assessments on a case-by-case basis.[128]

110. The ATCO Utilities pointed out that for utilities under PBR, there is no forecasting accuracy to assess with respect to income taxes. They added this is because the income tax expense is determined at the beginning of the PBR term, and it is indexed for each subsequent year. The ATCO Utilities contended that income tax expense calculated under the flow-through method comprises approximately three per cent of the total revenue requirement, and this small percentage should be considered when deciding whether deferral accounts for income taxes are required.[129]

111. AltaGas disagreed with Mr. Madsen's recommendation for the inclusion of a deferral account for temporary differences, and recommended the elimination of the Y factor for income tax timing differences for the 2018-2022 PBR term. It submitted that the continued true-up of only the income tax effect of temporary timing differences through a Y factor would amplify the under or over recovery of a utility's capital revenue requirement.[130] It submitted that under the 2018-2022 PBR term, the risks of capital investment have shifted to the utilities and any deferral account for temporary differences would be inconsistent with the incentive properties for PBR under the K-bar funding mechanism.[131]

112. AltaLink submitted that a deferral account for the deemed regulatory tax expense is not required, as long as there are applicable deferral accounts for the other non-income-tax revenue requirement components that cause differences between forecast and actual income tax, such as the deferral account for direct assigned capital project costs.[132]

113. FortisAlberta proposed that an income tax deferral account is justified and necessary.[133] FortisAlberta stated that deferral account treatment is a means for it to recover income tax amounts subject to reassessment by the Canada Revenue Agency (CRA). It noted that it has never been audited by the CRA, and until such an audit occurs, there is uncertainty with respect to the income tax deductions claimed.[134] FortisAlberta explained that a deferral account also provides for recovery of temporary income tax differences, such as contributions that it is required to pay to the Alberta Electric System Operator (AESO). FortisAlberta stated that these contributions are subject to significant variability and will materially impact income tax expense.[135]

114. The ATCO Utilities submitted that, when assessed against its recommended criteria for establishing deferral accounts, the Y factor dealing with income tax reassessments and temporary

128 Exhibit 22570-X0557, paragraph 89.
129 Exhibit 22570-X0746, paragraph 24.
130 Exhibit 22570-X0783, paragraphs 31-34.
131 Exhibit 22570-X0783, paragraph 31.
132 Exhibit 22570-X0043, paragraph 71.
133 Exhibit 22570-X0039, paragraph 34.
134 Exhibit 22570-X0039, paragraph 32.
135 Exhibit 22570-X0039, paragraph 33.

income tax differences established under the first PBR term is not required for the 2018-2022 PBR term.[136]

### Commission findings on deferral account proposals

### Criteria for establishing deferral accounts

115. The ATCO Utilities recommended that any deferral accounts for income taxes be established in accordance with the five criteria previously established by the Commission. Mr. Bell stated that deferral accounts should be established based on the five criteria set out by the Commission in its decision on the 2018-2022 PBR term.[137] The Commission will use the criteria referenced by Mr. Bell in assessing what deferral accounts, if any, should be established for income taxes for the distribution utilities.

116. The Commission finds that the five criteria listed by the ATCO Utilities should form the basis upon which any deferral accounts for income taxes for the transmission utilities should be decided. In addition, the Commission considers that the symmetry factor detailed in paragraphs 71-74 of Decision 2010-189[138] should also be considered, as "symmetry must exist between costs and benefits for both the Company and its customers."[139] However, the Commission will not make any specific findings with respect to income tax deferral accounts for the transmission utilities in this decision. The Commission considers that determinations with respect to tax deferral accounts for the transmission utilities are best made on the basis of a utility's specific circumstances and on a case-by-case basis, and considering the criteria articulated in this decision.

117. With respect to the distribution utilities, the Commission makes the following findings in relation to deferral accounts in the case of (1) statutory income tax rates and capital cost allowance rates; (2) temporary differences and income tax reassessments; and (3) other deferral accounts.

### Deferral account for statutory income tax rates and capital cost allowance rates

118. The Commission notes that the five criteria cited by Mr. Bell were those established by the Commission for the identification of eligible Y factor costs.[140] The third criterion for eligible Y factor treatment requires that costs should not have a significant influence on the inflation factor in the PBR formula. The Commission decided in Decision 2012-237 that major changes to the calculation of income tax payments, such as a change in income tax rates, should impact the entire economy and, as such, should be captured by the I factor. The Commission stated that due to the infrequent nature of such changes, it was not necessary to establish a Y factor account for changes in statutory income tax rates.[141]

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136 Exhibit 22570-X0044, paragraph 17.
137 Decision 2012-237, paragraph 631.
138 Decision 2010-189: ATCO Utilities, Pension Common Matters, Proceeding 226, Application 1605254-1, April 30, 2010.
139 Decision 2010-189, paragraph 73, quoting page 148 from Decision 2000-9: Canadian Western Natural Gas Company Limited, 1997 Return on Common Equity and Capital Structure, and 1998 General Rate Application, Applications 980413 and 980421, March 2, 2000.
140 Decision 2012-237, paragraph 631.
141 Decision 2012-237, paragraph 711.

119. In this proceeding, Mr. Madsen and AltaGas, as well as Dr. Carpenter,[142] argued that there is a lag to the impact of any changes to the statutory income tax rates being reflected in the I factor. The ATCO Utilities and AltaGas recommended that a deferral account be established for changes in statutory income tax rate changes. Mr. Bell and Mr. Madsen agreed.

120. The Commission is not persuaded by the submissions of parties that deferral account treatment for changes in statutory income tax rates is necessary to account for any lag in the I factor. The Commission maintains its finding on this issue from Decision 2012-237, that it is not necessary to establish a Y factor account for changes in statutory income tax rates. By extension, this finding extends to any changes in capital cost allowance rates.

121. The Commission addressed concerns with respect to the lagged approach to the I factor in Decision 2012-237 and concluded as follows:

> 243. The main difference between the two methods is that the approach preferred by the ATCO companies and Fortis ensures that the impact of actual inflation in any given year is reconciled soon after the year‘s end, while the alternative approach of using the actual inflation from the previous year involves a certain lag for such a true-up to occur. In this proceeding, parties’ concerns with the lagged approach seemed to be centered on the fact that the lag between the inflation index used in the PBR formula and **the actual inflation experienced in the economy would expose the companies to windfall gains or losses, although these would be transitory.** [emphasis added]
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> 244. The Commission considers that if inflation is higher in some years and lower in other years, as appears to be the general case in the economy, then using the most recent historical inflation rate will average out the effect of any regulatory lag over the PBR period. Indeed, as ATCO Gas observed in its argument, in the absence of a true-up, the I factor in 2009 would be higher than actual inflation. The opposite would have occurred in 2010, where the I factor without the true-up would be lower than actual inflation. **As such, inflation will tend to balance out over the PBR term, obviating the need to true-up the I factor through a separate regulatory proceeding.** [emphasis added]
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> …
>
> 248. **In light of these considerations, the Commission finds that the lagged approach currently used by ENMAX and proposed by AltaGas and EPCOR in this proceeding represents a better alternative as compared to the forecast and true-up method proposed by the ATCO companies and Fortis**.... **The Commission considers that this approach will provide a fair balance between accuracy and regulatory efficiency and will make the companies‘ PBR plans more transparent and simple to understand thereby furthering the objectives of the third Commission PBR principle.** [emphasis added]

122. The Commission therefore denies the request of the ATCO Utilities, AltaGas, Mr. Bell and Mr. Madsen that deferral accounts be established for the distribution utilities to account for any changes in statutory income tax rates and capital cost allowance rates.

142 Exhibit 22570-X0186, A72.

## Deferral account for temporary differences and income tax reassessments

123. Mr. Madsen recommended that a deferral account be established for all temporary differences. AltaGas argued against this recommendation. The Commission finds that the scope of this deferral account is too broad, and is not in accordance with the applicable criteria. The Commission considers that all costs that give rise to temporary differences are not outside the control of the utility's management, and not all of these costs are material. Consequently, Mr. Madsen's recommendation for a deferral account for all temporary differences is denied.

124. FortisAlberta currently has a deferral account for the income tax expense impact of reassessments made by the CRA in respect of income tax deductions that FortisAlberta has taken. With respect to this deferral account, the Commission finds that this is not beyond management's control, but is rather a safeguard against the actions taken by the management of FortisAlberta in deciding what income tax deductions should be taken by the company. FortisAlberta noted that maximizing allowable deductions for income tax, including Canderel/Rainbow pipeline expenditures, and capitalized overhead expenditures has allowed it to remain in a non-tax paying position.[143] FortisAlberta indicated that AESO contributions are a material deduction that it relies on to maintain a non-tax-paying position.[144]

125. The Commission considers that the decision to take these income tax deductions was, and is, within the control of the management of FortisAlberta. FortisAlberta was not required to take these income tax deductions, and if it had not taken the deductions, and ended up in a taxable position, then the resulting income tax expense would have formed part of the going-in rates for PBR, and customers would have been required to pay the resulting income taxes.

126. The Commission is aware that FortisAlberta had a CRA reassessment deferral account in place for 2012.[145] This was part of a negotiated settlement, and therefore it may have been part of the gives and takes associated with negotiated settlements. The Commission notes that it had previously denied FortisAlberta's request to establish a CRA reassessment deferral account.[146]

127. Based on the foregoing, the Commission denies the request of FortisAlberta that a CRA reassessment deferral account, in the form of a Y factor, be established for it for the 2018-2022 PBR term. However, in acknowledgement that a deferral account was in place for 2012-2017, should FortisAlberta be reassessed in relation to income tax expense for this period, it may bring this matter forward for consideration by the Commission.

## Other deferral accounts

128. FortisAlberta currently has a deferral account in case it becomes subject to income tax over the term of the PBR plan. With respect to this deferral account, the Commission considers that this is linked to the deductibility of the Canderel/Rainbow pipeline expenditures, disposal costs and AESO contributions, which the Commission finds are within the control of management. Consequently, this deferral account does not meet the criteria for being outside the

[143] Exhibit 22570-X0039, paragraph 28.
[144] Exhibit 22570-X0039, paragraph 33.
[145] Decision 2012-108: FortisAlberta Inc., Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Proceeding 1147, Application 1607159-1, April 18, 2012, paragraph 52.
[146] Decision 2010-309: FortisAlberta Inc. 2010-2011 Distribution Tariff – Phase I, Proceeding 212, Application 1605170-1, July 6, 2010, paragraph 307.

control of management, and the Commission therefore denies FortisAlberta's request to establish a deferral account for income taxes, in case the company becomes taxable over the term of the PBR plan.

129. The ATCO Utilities undertook an assessment of their currently established income tax deferrals, and whether they met the criteria previously applied by the Commission for the establishment of deferral accounts.[147] While these criteria are not exactly the same as the criteria established by the Commission for Y factor treatment, two of the criteria, being the materiality of the amount, and whether it is outside management's control, are the same.

130. Based on their assessment that the costs were immaterial and their assessment that management can control them, the ATCO Utilities recommended that the deferral account currently in place for the distribution utilities regarding income tax deductible capital costs is not necessary and should be eliminated.[148] The ATCO Utilities also submitted that the deferral account currently in place with respect to the deductibility of deferral accounts for income tax purposes relates to deferral accounts that are in place for non-income tax deferrals. They submitted that as long as these non-tax-related deferral accounts, such as ATCO Gas's weather deferral account, remain in place, it is fair that the income tax impact associated with these non-tax-related deferral accounts remain in place.

131. The Commission agrees with the assessment of the ATCO Utilities in support of their recommendation that the deferral account they currently have in place for income tax deductible capital costs is not necessary. These costs are not attributable to events outside the control of management. The utility's management will be responsible for monitoring changes to the income tax legislation and keeping apprised of any relevant court cases that may help identify any potential deductions that could be claimed. Management has to be satisfied that the deductions are justified and will stand up to any subsequent scrutiny by the taxation authorities. Based on this, the Commission finds that it is not necessary for the distribution utilities to establish a deferral account for any income tax deductible capital costs. The Commission also agrees with the ATCO Utilities that as long as any non-tax-related deferral accounts remain in place for the distribution utilities, the income tax aspect of these deferrals is to remain in place as well.

## 5.5 PBR implications

### Altering of income tax assumptions and practices during the PBR term, or on rebasing

132. AltaGas submitted that a utility should be able to alter its income tax assumptions and practices during the PBR term, if incentives regarding income taxes are built into the regulatory process. This would permit the utility to optimize its income tax position and mitigate potential income tax liabilities. Noting that income tax addbacks and deductions are derived from the accounting records, AltaGas suggested that any examination of changes in accounting assumptions and practices during the PBR term should also include a consideration of the impact on income taxes.[149]

133. Mr. Madsen recommended that the FIT method be implemented within going-in rates for the PBR utilities. He commented that the incentive for PBR utilities to claim maximum income

[147] Exhibit 22270-X0171, PDF pages 5-8.
[148] Exhibit 22270-X0171, PDF pages 5-8.
[149] Exhibit 22570-X0041, paragraphs 28-29.

tax deductions under the flow-through method will result in these deductions not being available for customers in the future, and therefore "is not a proper incentive and not in the public interest."[150] Mr. Madsen indicated that the use of the FIT method would partially address all the income tax irregularities that a utility can benefit from under PBR. He stated that under the FIT method, income tax expense from year to year would only fluctuate to the extent that net income fluctuates, unlike the current volatility of income tax levels for the PBR utilities.[151]

**Commission findings**

134. The Commission notes that the income tax expense component of the going-in rates for the 2018-2022 PBR term have been treated as a placeholder, pending the outcome of this GCOC proceeding.[152] Given that the Commission will not be directing a change to the income tax methodology for the taxable distribution utilities and has not adopted an all-inclusive Y factor for the treatment of income tax, few revisions to the income tax expense placeholders will be required. However, as a result of the Commission's decision to eliminate AltaGas' Y factor for tax-timing differences, AltaGas's 2018 base K-bar calculation will need to be revisited.[153]

135. The Commission notes that adjustments will be made to the distribution utilities' going-in PBR rates in future proceedings. For example, adjustments to going-in rates will be required to reflect 2017 approved capital tracker amounts and to account for any approved depreciation changes. The Commission directs AltaGas to revise the calculation of its base K-bar to incorporate the findings in this decision as part of the next proceeding addressing adjustments to AltaGas's going-in PBR rates. To the extent that ATCO Gas, ATCO Electric or FortisAlberta consider that this decision impacts the calculation of the income tax expense included in 2018 going-in rates, this may similarly be addressed in the next proceeding considering any required adjustments to their respective going-in PBR rates.

136. The Commission considers that, as a result of eliminating the majority of Y factor treatment for income tax related matters, it is incumbent upon a taxable utility under PBR to notify the Commission of any changes to its tax policy or other changes that may result in changes to the utility's taxable income and/or income tax expense. The Commission reminds the taxable distribution utilities that the required attestation certificates filed in the annual PBR rate adjustment filings must identify and describe any changes in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts.[154]

# 6 Relevant changes in global economic and Canadian capital market conditions since the 2016 GCOC decision

137. Consistent with its practice in past GCOC decisions, in this section the Commission considers prevailing economic and market conditions in its determination of a fair approved ROE and approved deemed equity ratios.

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[150] Exhibit 22570-X0557, paragraph 235.
[151] Exhibit 22570-X0557, paragraphs 232-235.
[152] Decision 22394-D01-2018: Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities, First Compliance Filing, Proceeding 22394, February 5, 2018, Sections 6.3.1 and 6.3.2.
[153] In Decision 22394-D01-2018, the Commission approved AltaGas' base K-bar calculation, which excluded any tax implications given AltaGas's Y factor, on a placeholder basis.
[154] Decision 2012-237, paragraph 862.

138. In the 2016 GCOC decision, the Commission concluded that the "global and Canadian economic and capital market conditions were different from the conditions that existed during the global financial crisis of 2008-2009," but lingering effects of the global financial crisis continued.[155] The Commission was presented with forecasts that indicated a continued lacklustre performance of the Canadian economy in 2016, with gross domestic product (GDP) growth and inflation forecasts below historical averages, but with some amount of recovery expected by the end of 2017. At that time, the Commission was persuaded that interest rates were likely to rise in 2017, but was uncertain about the speed and magnitude of the expected increase.

139. In the present GCOC proceeding, there was general consensus among witnesses that market conditions have improved since the time of the 2016 GCOC decision, as demonstrated by central banks raising policy interest rates, monetary stimulus programs in the U.S. and Europe continuing to unwind, a moderate recovery in oil prices and the strengthening of the Canadian dollar (CAD), among other indicators.[156]

140. A summary of the evidence and submissions on aspects of global and Canadian macroeconomic conditions and how these should influence the Commission's determination of a fair approved ROE and deemed equity ratios is presented below.

## 6.1 Macroeconomic conditions

141. Mr. Buttke, Mr. Hevert and Dr. Cleary agreed that there has been generally positive and strengthening economic growth globally and in North America since the 2016 GCOC decision.[157] Mr. Hevert cited a March 8, 2018 speech by one of the Bank of Canada's deputy governors that referred to this as "geosynchronous growth."[158] Mr. Buttke referred to a report by the International Monetary Fund (IMF) indicating that a global cyclical recovery is underway, and that world GDP growth is expected to rise from 3.2 per cent in 2016 (the weakest annual growth since the financial crisis) to 3.6 per cent in 2017 and 3.7 per cent in 2018.[159]

142. In his evidence, Mr. Thygesen cast doubt on historical and projected global and national economic growth.[160] However, during the oral hearing he agreed that the data shows positive GDP growth since the 2016 GCOC decision, and that this growth is forecast to continue.[161]

143. Mr. Coyne considered global economic growth to be about the same as during the 2016 GCOC proceeding, saying that global "GDP is not growing at breakout levels, but we haven't experienced another recession."[162]

144. Regarding the U.S. economy, witnesses generally agreed that it has been on a path of mostly solid growth and job creation for the last few years.[163] Mr. Coyne cited recent remarks by

155 Decision 20622-D01-2016, paragraph 81.
156 Transcript, Volume 3, pages 560-562. Transcript, Volume 5, pages 905-907. Transcript, Volume 6, pages 1154-1156. Transcript, Volume 10, pages 2071-2072.
157 Transcript, Volume 3, page 560. Transcript, Volume 6, pages 1154-1155. Transcript, Volume 10, pages 2071-2072.
158 Transcript, Volume 6, page 1155. Exhibit 22570-X0823, PDF page 3.
159 Exhibit 22570-X0179, PDF page 13.
160 Exhibit 22570-X0551, PDF page 35.
161 Transcript, Volume 8, pages 1657-1659.
162 Transcript, Volume 5, page 906.

the U.S. Federal Reserve System (the Fed) that economic activity in the U.S. "has been rising moderately [in 2017] and is expected to continue its moderate pace of expansion over the next three years."[164] Mr. Buttke pointed to the Bank of Canada's October 2017 *Monetary Policy Report* (MPR) that stated the U.S. economy is projected to expand at a moderate pace; about two per cent on average over 2017 to 2019.[165]

145. With regard to the Canadian and Alberta economies, Dr. Cleary stated that Canadian economic growth exceeded expectations during 2017, and both Canada and Alberta are expected to experience more moderate but solid GDP growth going forward.[166] Dr. Cleary referred to the Bank of Canada's October 2017 MPR, which predicts real GDP growth of 3.1 per cent in 2017, followed by growth rates of 2.1 per cent in 2018 and 1.5 per cent in 2019.[167] Dr. Cleary concluded that "the Canadian and Alberta economies are expected to grow at subdued, but healthy levels in the intermediate term."[168] The CCA stated that while the forecasts for national GDP growth are positive, the trend is a declining or slowing one: 3.0 per cent in 2017, 2.2 per cent in 2018 and 1.6 per cent in 2019.[169]

146. The utilities' witnesses generally agreed with the GDP values presented by Dr. Cleary and referenced similar growth figures.[170] For example, Mr. Buttke drew the Commission's attention to a March 8, 2018 speech in which one of the Bank of Canada's deputy governors stated "the Canadian economy is progressing well. Following a decade of many setbacks, 2017 was a year of robust economic growth – 3 per cent for the year as a whole."[171]

147. Mr. Coyne,[172] Mr. Buttke,[173] Dr. Cleary[174] and Mr. Thygesen[175] reminded the Commission that future global and national growth is uncertain. Some witnesses referred to the presence of market volatility as indicative of this global uncertainty.[176] All witnesses acknowledged that there was substantial uncertainty around U.S. trade policy, notably the current renegotiation of the North American Free Trade Agreement (NAFTA), and its potential impact on Canadian and North American growth projections.[177]

148. For Alberta, Mr. Buttke and Dr. Cleary both explained that projections for economic growth have been significantly upgraded since the 2016 GCOC decision, when Alberta was immediately struggling with the collapse in oil prices and negative GDP growth of 3.6 per cent

163 Exhibit 22570-X0179, PDF page 18. Exhibit 22570-X0153.01, PDF page 96. Exhibit 22570-X0131, PDF page 19. Exhibit 22570-X0562.01, PDF pages 17-18.
164 Exhibit 22570-X0131, PDF page 19.
165 Exhibit 22570-X0179, PDF page 20.
166 Exhibit 22570-X0562.01, PDF page 5.
167 Exhibit 22570-X0562.01, PDF page 19.
168 Exhibit 22570-X0562.01, PDF page 77.
169 Exhibit 22570-X0888, paragraph 31.
170 Transcript, Volume 3, page 563. Exhibit 22570-X0179, PDF page 13. Transcript, Volume 5, page 908. Transcript, Volume 6, pages 1157-1158.
171 Transcript, Volume 4, page 633. Exhibit 22570-X0823, PDF page 3.
172 Exhibit-22570-X0131, PDF page 24.
173 Exhibit 22570-X0179, PDF page 15.
174 Exhibit 22570-X0562.01, PDF page 21.
175 Exhibit 22570-X0551, paragraph 43.
176 Exhibit-22570-X0131, PDF page 24. Exhibit 22570-X0179, PDF page 16.
177 Exhibit 22570-X0153.01, PDF pages 36-42. Exhibit 22570-X0179, PDF page 6. Transcript, Volume 3, page 562. Transcript, Volume 5, page 907. Transcript, Volume 6, page 1155. Transcript, Volume 10, page 2071.

in 2016. Mr. Buttke cited Bloomberg data, which forecast Alberta's GDP to be 4.1 per cent in 2017, 2.5 per cent in 2018 and 2.0 per cent in 2019.[178]

149. Notwithstanding Mr. Buttke's general view of Alberta's economic growth projections, he tempered this view by noting that global oil prices have risen since the 2016 GCOC decision, in that the benchmark price known as West Texas Intermediate (WTI) moved to over $60 per barrel in February 2018, from just below $50 per barrel in May 2016.[179] However, Alberta's producers are expected to miss out on much of that improvement since the Alberta benchmark price known as Western Canada Select (WCS) fell from around $40 per barrel in early 2017 to around $35 per barrel in February 2018. As a result, the WTI-WCS discount had widened to nearly $30 per barrel in early 2018, compared to $10-$24 per barrel in 2017, thus significantly reducing the benefit to Albertan producers of higher WTI prices.[180]

150. In the period leading up to the 2016 GCOC decision, the CAD weakened significantly against the U.S. dollar (USD). The CAD/USD exchange rate was not a concern among witnesses during this proceeding. Mr. Buttke explained that in late 2016 and through most of 2017, the CAD strengthened relative to the USD, with the CAD/USD exchange rate settling at around $0.80 USD. Mr. Buttke also referred to Bloomberg's panel of economists, which "expect the CAD/USD exchange to stabilize around current levels and strengthen marginally to 83 cents over the next few years."[181] All other witnesses acknowledged and confirmed this expected stabilization.[182]

151. AltaLink, EPCOR and Fortis referred to the comments of Mr. Hevert, stating that although growth projections for Alberta's GDP, oil prices and the CAD/USD exchange rate may be relevant for firms considering their own growth projections, these should not be the focus of the Commission's analysis in this proceeding. Mr. Hevert explained that the Commission should focus on the broader North American market in which capital is raised in order to capture the true opportunity cost of capital.[183]

### 6.2 Inflation

152. Dr. Cleary explained that Canadian inflation from 1992 to 2016 averaged 1.81 per cent, with a median of 1.75 per cent. This is within the Bank of Canada's one to three per cent target range, established since the policy's adoption in 1991, and in line with its target rate of two per cent.[184]

153. Dr. Cleary cited the Bank of Canada's prediction in its October 2017 MPR that inflation will remain below the bank's target rates of 1.5 per cent in 2017 and 1.7 per cent in 2018, before

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178 Exhibit 22570-X0562.01, PDF page 29. Exhibit 22570-X0749, PDF page 104.
179 Decision 20622-D01-2016, paragraph 42.
180 Exhibit 22570-X0749, PDF page 103.
181 Exhibit 22570-X0179, PDF pages 42-43.
182 Transcript, Volume 3, page 140. Transcript, Volume 5, page 907. Transcript, Volume 6, page 1155. Transcript, Volume 10, page 2071.
183 Exhibit 22570-X890.01, paragraph 21.
184 Exhibit 22570-X0562.01, PDF page 7.

increasing to 2.1 per cent in 2019. Dr. Cleary noted that these predictions were in line with those of the Consensus Economics forecast and the IMF.[185]

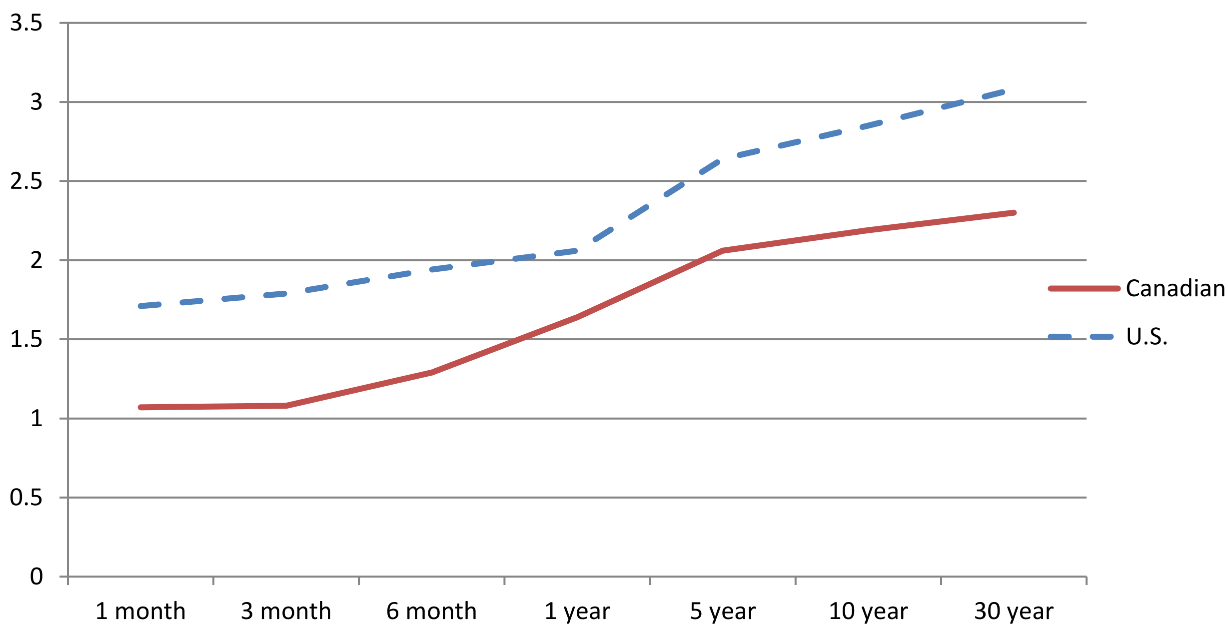
154. Mr. Buttke and Mr. Hevert provided similar evidence pointing to rising inflation since 2016, and a broad expectation that inflation will continue to rise modestly toward two per cent in the U.S. and Canada. In contrast, Mr. Thygesen argued that inflation is low and falling.[186]

## 6.3 Interest rate environment

155. At the close of record for the 2016 GCOC proceeding on June 29, 2016, the U.S. federal funds rate and the Bank of Canada's overnight interest rate, both short-term policy interest rates, were at 0.5 per cent.[187] Since the 2016 GCOC decision was issued on October 7, 2016, the Fed has raised the target for the U.S. federal funds rate five times, to 1.75 per cent as of March 21, 2018.[188] The Bank of Canada raised its overnight interest rate three times over the same period, to 1.25 per cent as of January 17, 2018.[189]

156. Figure 1 below depicts the yield curves for Government of Canada (GOC) and U.S. government bonds as of March 26, 2018. In past GCOC proceedings, witnesses explained that monetary policy works at the short end of the yield curve via the overnight rate, and its influence weakens as the maturity of the bond increases. Therefore, normal yields on long-term GOC bonds are not as affected by current monetary policy as short-term interest rates are.[190]

**Figure 1 Yield curves for GOC and U.S. government bonds as of March 26, 2018[191]**

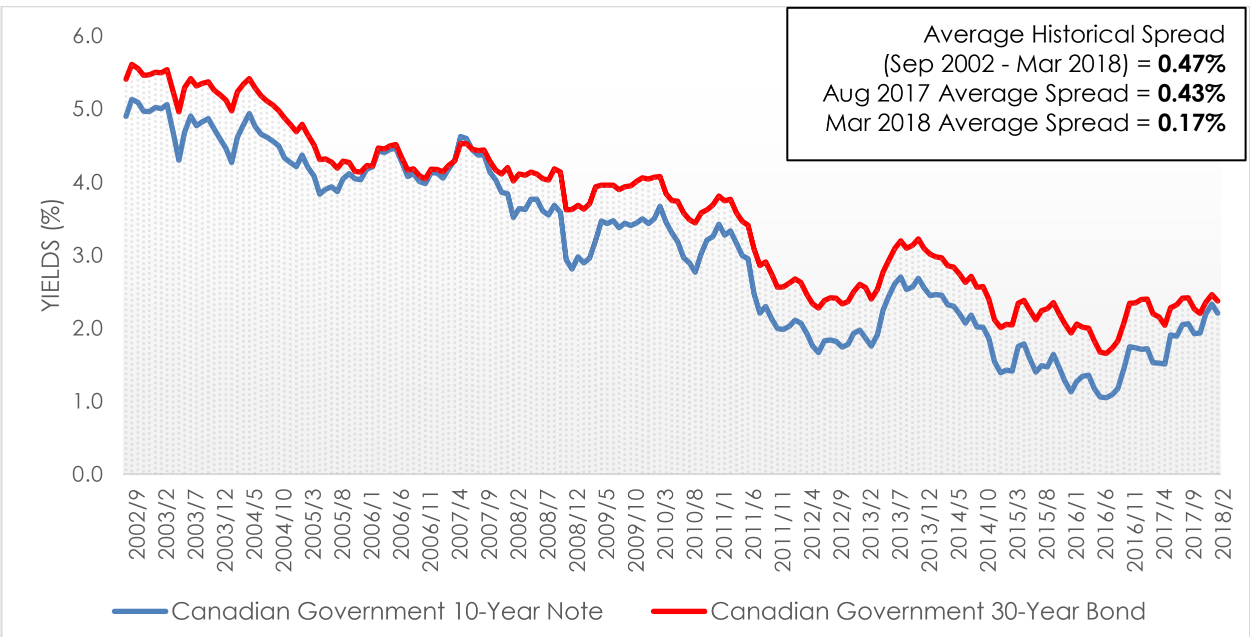



185 Exhibit 22570-X0562.01, PDF page 20.
186 Exhibit 22570-X0551, PDF page 37.
187 Decision 20622-D01-2016, paragraph 50.
188 Exhibit 22570-X0153.01, PDF page 28 indicates increases on these dates: December 14, 2016, March 15, 2017, and June 14, 2017. Exhibit 22570-X0767.01, PDF page 29 indicates an increase on December 13, 2017. Exhibit 22570-X0851, PDF page 1 indicates an increase on March 21, 2018, to 1.75 per cent.
189 Exhibit 22570-X0767.01, PDF page 29.
190 Decision 20622-D01-2016, paragraph 51.
191 Exhibit 22570-X0878.

157. Dr. Cleary observed that U.S. rates exceeded Canadian rates across the entire yield curve. At the long end of the yield curve, U.S. rates exceeded those in Canada by approximately 66 basis points (bps) for 10-year bonds and 78 bps for 30-year bonds.[192] Dr. Cleary further explained that according to the 10-year government yield forecasts for Canada and the U.S. from the Consensus Economics forecasts in October 2017, the spread between U.S. and Canadian rates is expected to narrow "to 40 bps by October of 2018."[193]

158. Mr. Coyne observed that while the yields for 10-year and 30-year GOC bonds increased from January 2016 to August 2017, the spreads between these 10-year and 30-year GOC bonds have decreased from 79 bps in January 2016 to 43 bps in August 2017, which is below the historical average of 48 bps from 2002 to 2017.[194] Mr. Thygesen referenced several articles indicating that the U.S. yield curve is flattening with the difference between short-term and long-term yields being at its lowest since November 2007.[195] As of March 16, 2018, the spread between the 10-year and 30-year GOC bonds was 11 bps, whereas the average for the month of March 2018 was 17 bps. This information is set out in Figure 2.

**Figure 2 Canadian government bond yields, 10-year vs. 30-year[196]**




159. Mr. Buttke,[197] Dr. Villadsen,[198] Mr. Coyne,[199] Mr. Hevert[200] and Dr. Cleary[201] all agreed that the current GCOC proceeding took place during a rising interest rate environment.

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192 Exhibit 22570-X0562.01, PDF page 23. Exhibit 22570-X0878.
193 Exhibit 22570-X0562.01, PDF page 23.
194 Exhibit 22570-X0131, PDF page 21.
195 Exhibit 22570-X0551, PDF pages 20-25.
196 Exhibit 22570-X0835.
197 Exhibit 22570-X0179, PDF page 59. Transcript, Volume 3, pages 574-575.
198 Exhibit 22570-X0193.01, PDF page 23.
199 Exhibit 22570-X0131, PDF page 28. Transcript, Volume 5, page 933.
200 Exhibit 22570-X0153.01, PDF page 10. Transcript, Volume 6, pages 1159-1160.
201 Exhibit 22570-X0562.01, PDF page 22. Transcript, Volume 10, pages 2076-2077.

Looking forward, these witnesses all agreed that 10-year and 30-year GOC bond yields are expected to increase; however, they disagreed on the timing and magnitude of the expected increases over the test period.

160. These same witnesses also agreed that central banks raising their policy interest rates together with increasing inflation expectations are causing short-term interest rates to rise, but that these are only some of the factors. Dr. Cleary indicated that the Bank of Canada is expected to raise its policy interest rate one or two more times in 2018.[202] However, Dr. Cleary pointed out that just because the U.S. 10-year yields go up does not necessarily mean the GOC 30-year yields will go up,[203] and that at the time of this proceeding the GOC 30-year bond yields have remained low despite increases in short-term interest rates.[204] Similarly, the CCA indicated that only the short-term rates are increasing, adding that long-term rates are lower than they were a year ago when short-term rates started to increase.[205] Mr. Thygesen pointed out that the interest rates for 10-year U.S. and GOC bonds have overall been on a downward trend since 1990.[206] Rising short-term rates and falling long-term rates result in a flattening yield curve.

161. Another cause for the expected increase in short-term interest rates mentioned by the witnesses was the unwinding of quantitative easing policies in the U.S. and Europe. Mr. Buttke mentioned that due to the unwinding of U.S. monetary stimulus, the market expects incremental upward pressure on U.S. Treasury 10-year yields of approximately 40 bps or more during the 2018-2020 GCOC period.[207] Dr. Cleary stated that he had no reason to disagree with this assessment,[208] while Mr. Coyne commented that this was a conservative estimate and that the upward pressure on U.S. Treasury 10-year yields could be as high as 100 bps.[209]

162. Another cause suggested for the increase in short-term interest rates was increasing economic growth in North America and globally,[210] as this shifts the supply and demand for money in capital markets.[211]

## 6.4 Credit spreads

163. In past GCOC decisions, the Commission has accepted that credit spreads are an objective measure, based on observable market data, which help inform the Commission about investors' risk perceptions.[212] In this proceeding, the parties pointed out that credit spreads for the Canadian A-rated utilities have narrowed since the 2016 GCOC proceeding.

164. Mr. Coyne explained that credit spreads are a measure of the difference between the yields of different securities, and these are typically expressed as a spread between bonds of the same maturity, but different quality in terms of risk.[213] "Credit spread," as referred to in this

[202] Transcript, Volume 10, page 2077.
[203] Transcript, Volume 10, page 2080.
[204] Transcript, Volume 10, page 2081.
[205] Exhibit 22570-X0888, paragraph 107.
[206] Exhibit 22570-X0551, PDF page 28.
[207] Exhibit 22570-X0179, PDF page 66.
[208] Transcript, Volume 10, pages 2079-2080.
[209] Transcript, Volume 5, page 911.
[210] Transcript, Volume 6, page 1160.
[211] Transcript, Volume 5, page 910.
[212] Decision 20622-D01-2016, paragraphs 86 and 334.
[213] Exhibit 22570-X0131, PDF page 22.

decision, is the difference between the yield on 30-year Canadian A-rated utility bonds and the yield on 30-year GOC bonds.

165. In the 2016 GCOC decision, the Commission concluded that:

> The average credit spread prior to the financial crisis (2001-2007) was around 100 bps, and the average credit spread after the financial crisis (late 2009-early 2015) remained relatively stable in the 130 to 150 bps range. In late June 2015, credit spreads began to widen above 150 bps and reached 190 bps by the end of 2015. Credit spreads then increased further to 206 bps by February 3, 2016, before declining to about 170 bps as of the start of the oral hearing in late May 2016. Thus, Dr. Villadsen, Dr. Booth and Dr. Cleary pointed out that, at the start of the current proceeding, the credit spread was elevated by some 100 bps relative to what they considered to be its typical or "normal" level. Mr. Hevert pointed out that credit spread volatility has increased as well.

166. Specifically, as demonstrated in figures 3 and 4 below, the credit spread was 179 bps at the close of record of the 2016 GCOC proceeding versus 130 bps in March 2018, at the time of the hearing for this proceeding, a decrease of 49 bps.

167. Dr. Cleary and Dr. Villadsen agreed that the credit spread still remained slightly elevated compared to the typical or normal level prior to the financial crisis, although both expected it may continue to narrow.[214] Mr. Coyne and Mr. Hevert were of the view that the credit spread is currently at normal levels.[215] Mr. Coyne considered that the credit spread will remain stable over the test period,[216] while Mr. Hevert expressed the view that the credit spread may widen.[217] Mr. Thygesen concluded that even if interest rates are to rise, the effect on the credit spread is expected to be muted and can be expected to mitigate the impact of rising rates on utilities.[218]

[214] Transcript, Volume 3, pages 577-579. Transcript, Volume 10, page 2086.
[215] Transcript, Volume 5, pages 915-916. Transcript, Volume 6, page 1165.
[216] Transcript, Volume 5, page 919.
[217] Transcript, Volume 6, pages 1166-1167.
[218] Exhibit 22570-X0551, paragraph 51.

**Figure 3 30-year Canadian A-rated utility bond yields, 30-year GOC bond yields[219]**

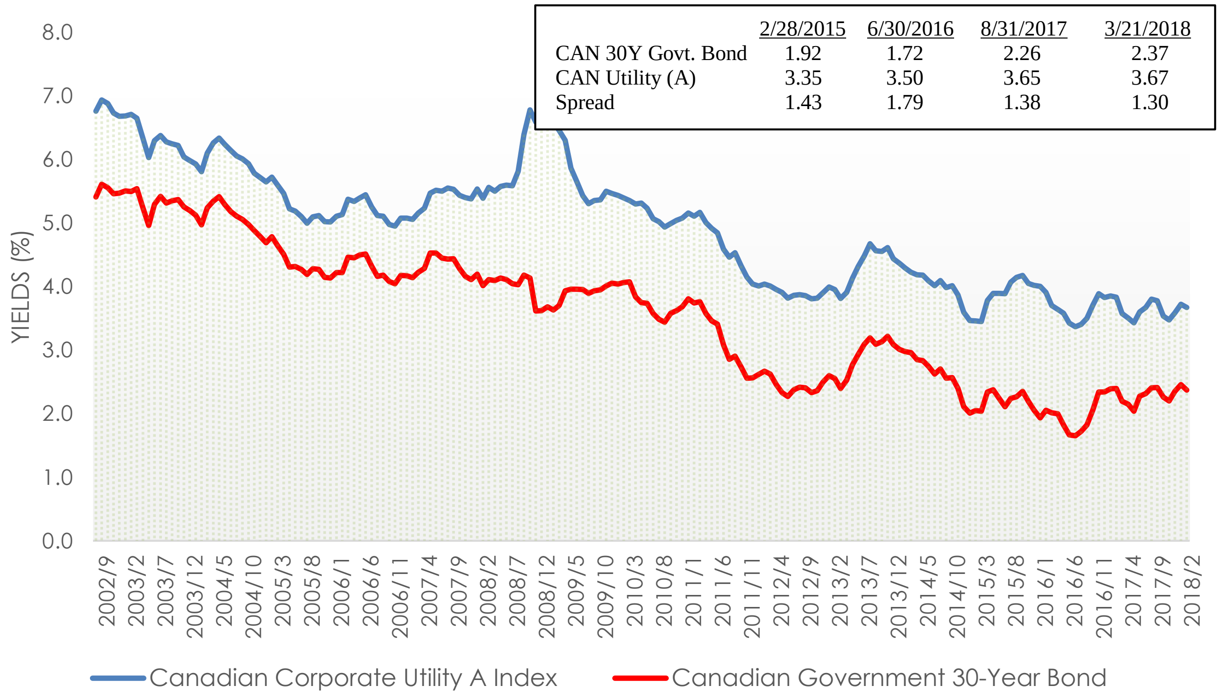
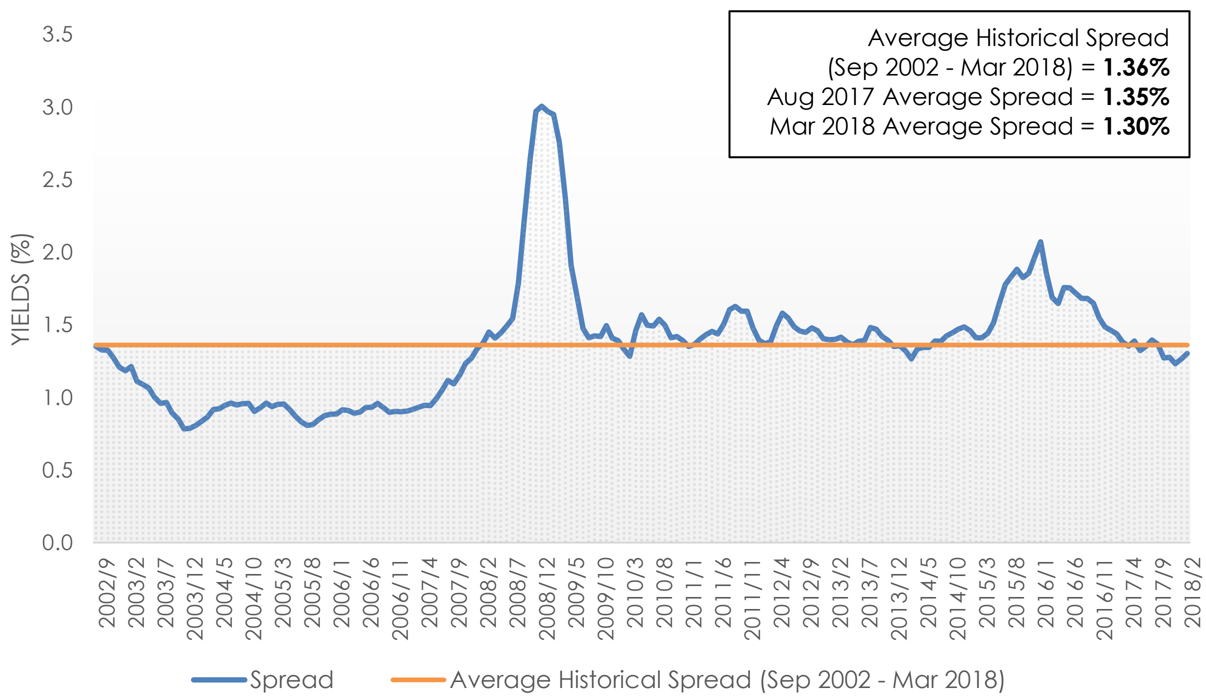


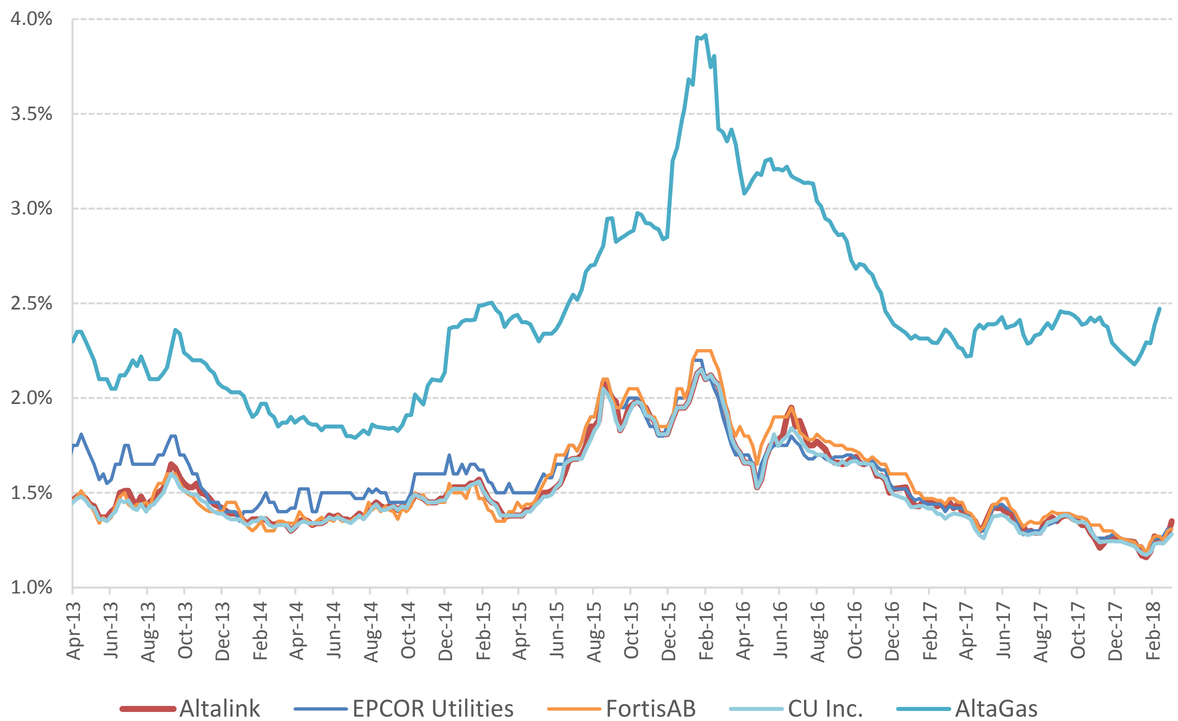

**Figure 4 Credit spread between 30-year Canadian A-rated utility bond yields and 30-year GOC bond yields[220]**




219 Exhibit 22570-X0835. Exhibit 22570-X0836.
220 Exhibit 22570-X0835.

168. Mr. Buttke provided data that the credit spread for certain Alberta utilities has narrowed since the time of the 2016 GCOC proceeding.[221] Mr. Hevert[222] provided similar information for other Alberta utilities. This is shown in Figure 5 below.

**Figure 5 30-year credit spreads for Alberta utilities[223]**




169. The Commission asked in its final issues list if there would be a "clear and objective measure on the record by which the Commission can determine which factor or factors explain any changes in utility credit spreads."[224] To this, Mr. Coyne responded:

> Though credit spreads provide information on the overall level of perceived risk in the market, and changes or trends in credit spreads can be meaningful in assessing investors' required returns, credit spreads are the product of a variety of complex market influences impacting both the underlying security (*e.g.*, treasury yield), and the security being measured (*e.g.*, a 30-year A rated utility bond yield). Spreads typically move higher when there is greater risk of default in the sector, or in the economy as a whole, and vice versa, as default risk decreases. But this is not the only factor affecting spreads. Investor demand for bonds of differing quality and risk in relation to other investment options also plays a role. For these reasons, credit spreads are a relative indicator, a culmination of market information as it pertains to government and corporate yields, but cannot be quantified by a specific set of factors.[225]

221 Exhibit 22570-X0179, PDF pages 63-64. Exhibit 22570-X0815.
222 Exhibit 22570-X0863.
223 Underlying data provided in exhibits 22750-X0816 and 22750-X0864.
224 Exhibit 22570-X0078, paragraph 3.
225 Exhibit 22570-X0131, PDF page 24.

170. Dr. Cleary stated that changes in government yields and yield spreads tend to go in opposite directions, and offset one another to a certain extent.[226] In addition, he calculated that the correlation coefficient between 30-year GOC bonds and A-rated utility yield spreads over the January 2003 to November 2017 period was -0.49, which indicates a strong negative relationship.[227] Mr. Hevert commented that while credit spreads and interest rates are inversely related over longer horizons, within shorter periods that relationship may be less stable.[228] Mr. Buttke expressed a similar view.[229]

171. In the 2016 GCOC proceeding, Mr. Hevert concluded that there was little question that the increase in credit spreads suggested some measure of increased risk perception among Canadian utility investors.[230] However, AltaLink, EPCOR and Fortis, relying on Mr. Hevert's evidence in this proceeding, came to a different conclusion in the current proceeding. They submitted that although credit spreads have narrowed since the 2016 GCOC proceeding, that is not a basis for concluding that the risk perceptions of utility equity investors have decreased.[231]

172. In contrast, the UCA pointed out that:

> … in the 2016 GCOC proceeding, the utilities' witnesses focused on elevated utility credit spreads, while ignoring the impact of prevailing low interest rates. In this proceeding, the utilities' witnesses now heavily stress the anticipated (but far from certain) rise in interest rates, while ignoring or heavily downplaying the significance of the notable decrease in utility credit spreads. This is so notwithstanding the net impact in both scenarios is similar – i.e. low borrowing costs for utilities.[232]

173. Given that debt financing for Alberta's utilities remains at historic lows, the UCA concluded that the cost of equity must also be similarly low, on a relative and absolute basis, given the strong relationship between the cost of debt and the cost of equity.[233]

## 6.5 Market volatility

174. In the 2016 GCOC proceeding, Mr. Hevert, Dr. Villadsen, Dr. Cleary and Dr. Booth drew the Commission's attention to the fact that stock market volatility had increased in late 2015 and early 2016.[234] In particular, two measures of the market's expectations for volatility were relied upon during that proceeding to demonstrate this point: (1) the VIXC, which measures the 30-day implied volatility of the Standard & Poor's (S&P) Toronto Stock Exchange (TSX) 60 index (representing the stock market in Canada); and (2) the VIX, which measures the 30-day implied volatility of the S&P 500 index (representing the stock market in the U.S.). During the 2016 GCOC proceeding, witnesses explained to the Commission that these indexes are "highly

226 Exhibit 22570-X0562.01, PDF page 27.
227 Exhibit 22570-X0562.01, PDF page 14.
228 Exhibit 22570-X0741.01, PDF page 13.
229 Exhibit 22570-X0749, PDF page 91.
230 Decision 20622-D01-2016, paragraph 64.
231 Exhibit 22570-X0890.01, paragraph 29.
232 Exhibit 22570-X0913, paragraph 11.
233 Exhibit 22570-X0897.01, paragraph 36.
234 Decision 20622-D01-2016, paragraph 68.

visible, and often-reported barometers of investor risk sentiments" and are often referred to as the "investor fear gauge."[235]

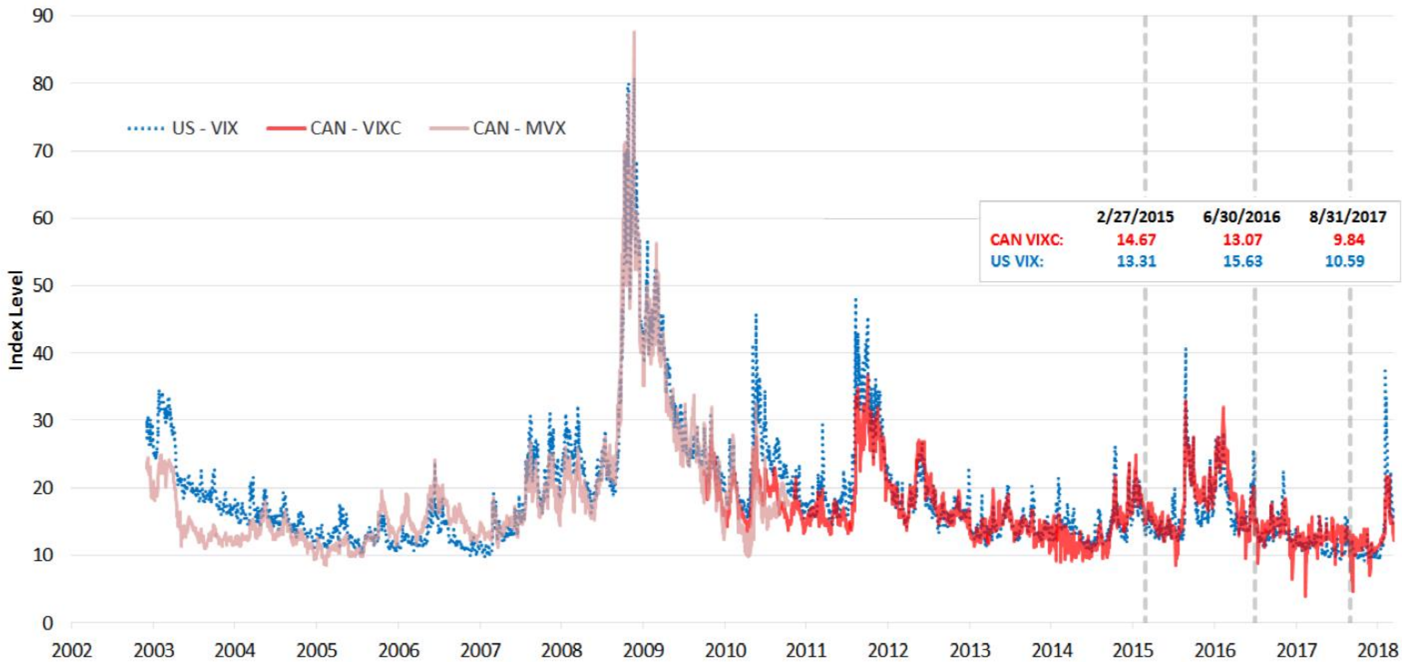
175. In the 2016 GCOC proceeding, the witnesses agreed that the long-term average for both the VIXC and VIX was about 20.[236] They further pointed out that volatility stayed at relatively low levels during 2013 and 2014, but in August 2015, the VIXC and VIX spiked to 33 and 40, levels not seen since October 2011, and in January 2016 volatility remained elevated and stood at about 26 for both indices.[237] At the close of record for the 2016 GCOC proceeding, the VIXC and VIX were approximately 13 and 16, respectively, as shown in Figure 6.

176. In the 2016 GCOC proceeding, the Commission concluded that the observed instability in estimators of investor perceptions of near-term market uncertainty, like the VIX and the VIXC, were indicative of increased investor uncertainty in the 2016-2017 period compared to investor uncertainty at the time of the 2013 GCOC proceeding.[238]

177. In the current proceeding, Mr. Coyne,[239] Mr. Buttke,[240] Dr. Villadsen,[241] Mr. Hevert[242] and Dr. Cleary[243] all provided evidence on the VIXC and VIX. As shown in Figure 6, the VIXC and the VIX stood at approximately 10 and 11, respectively, at the end of August 2017. These levels spiked briefly in early February 2018, reaching levels of approximately 22 and 33, respectively. At the end of March 2018, during the time of the hearing, these levels were roughly 12 and 18, respectively.[244]

235 Decision 20622-D01-2016, paragraph 68.
236 Decision 20622-D01-2016, paragraph 69.
237 Decision 20622-D01-2016, paragraph 69.
238 Decision 20622-D01-2016, paragraph 91.
239 Exhibit 22570-X0131, PDF pages 24-25.
240 Exhibit 22570-X0179, PDF pages 47-49.
241 Exhibit 22570-X0193.01, PDF pages 28-29.
242 Exhibit 22570-X0153.01, PDF pages 31-33.
243 Exhibit 22570-X0562.01, PDF page 16.
244 Transcript, Volume 10, page 2097.

**Figure 6 Canadian and U.S. stock market volatility indexes**[245]




Source: VIX and VIXC - from Bloomberg, MVX from Canadian Derivatives Exchange

178. While the VIXC and VIX have generally decreased since January 2016, Mr. Coyne,[246] Dr. Villadsen[247] and Mr. Hevert[248] did not agree that this was indicative of lower volatility in the market. All of these witnesses reminded the Commission that the VIXC and VIX are "near-term" measures of market volatility, extending out 30 days, and they each pointed to alternative indicators of volatility, such as the State Street Investor Confidence Indices,[249] the SKEW Index,[250] and the term structure of volatility of the Chicago Board Options Exchange.[251] During the hearing, Mr. Buttke confirmed that he did not provide evidence on the SKEW Index during the 2016 GCOC proceeding.[252]

179. Dr. Cleary underscored that there is always a certain amount of volatility in the market and suggested that rather than focus on temporary spikes, the VIX and VIXC should be examined over a period of time. He further suggested that since these values have not remained elevated over a sustained period of time, this may indicate market anxiety is above normal levels.[253] Dr. Cleary also referred to alternative indicators of market risk, including the Mercer

245 Exhibit 22570-X0817.
246 Transcript, Volume 5, pages 923-926.
247 Transcript, Volume 3, page 586.
248 Transcript, Volume 6, page 1176.
249 Exhibit 22570-X0131, PDF page 26.
250 Exhibit 22570-X0193.01, PDF page 30. Exhibit 22570-X0179, PDF pages 49-51.
251 Exhibit 22570-X0153.01, PDF pages 34-35.
252 Transcript, Volume 3, page 588.
253 Transcript, Volume 10, page 2098.

Pension Health Index,[254] the trailing price-earnings ratio for the S&P/TSX Composite Index, the U.S. S&P 500 Index[255] and the Financial Stress Index.[256]

180. Mr. Thygesen stated:

> The VIX and VIXC are basically half the levels of 2016. This has led to shift in utility evidence basically saying, 'yes but look what is lurking around the corner'. In my view the treatment of the evidence should be consistent. If the weight was on current conditions in 2016 then the weight should be on current conditions now.[257]

181. Mr. Thygesen pointed to yet other indicators that show lower volatility in the market, including the Chicago Fed National Financial Conditions Index, the Kansas City Financial Stress Index and the St. Louis Financial Stress Index.[258]

182. Interveners argued that the VIXC and VIX are at generally lower levels than during the 2016 GCOC proceeding, and that gives weight to a decrease in the approved ROE.[259] The utilities pointed to increases in the VIXC and VIX observed in February 2018, stating that because of the movement in these indices, the argument that the approved ROE should be lowered because of lower market volatility is no longer defensible.[260]

183. During the hearing, Dr. Cleary agreed with recent statements made by a Bank of Canada deputy governor that more normal levels of volatility are returning to markets. Dr. Cleary elaborated, saying "The VIX [and VIXC] were a little bit below average on Tuesday [March 20, 2018], and they were well below average in the fall. So it seems to be the case, we have volatility. And there's always going to be volatility in the market."[261]

### 6.6 Overall conclusions of the witnesses

184. Mr. Buttke's view was that global markets have been strong and are likely to continue to strengthen in the future. He pointed to central banks raising policy rates, with additional rate hikes predicted. Quantitative easing programs are being reversed in the U.S. and Europe, which will further cause interest rates to rise.[262]

185. Dr. Villadsen observed that both utility bond yields and government bond yields are expected to increase over the next several years. She pointed to a spike in the VIXC and VIX in February 2018, reminding the Commission that they are just one measure and that "they are one-month-ahead indicators of volatility, and they're meaningful in that sense. They're not meaningful in a long-term sense."[263]

254 Exhibit 22570-X0562.01, PDF page 16.
255 Exhibit 22570-X0562.01, PDF pages 15-16.
256 Transcript, Volume 10, page 2098.
257 Exhibit 22570-X0551, PDF page 5.
258 Exhibit 22570-X0551, PDF pages 49-51.
259 Exhibit 22570-X0897.01, PDF pages 16-17. Exhibit 22570-X0888, PDF page 20.
260 Exhibit 22570-X890.01, PDF pages 18-19. Exhibit 22570-0900, PDF pages 24-25.
261 Transcript, Volume 10, pages 2097-2098.
262 Exhibit 22570-X0179, PDF pages 4-6.
263 Transcript, Volume 3, page 164.

186. Mr. Hevert summarized his view by stating that observed and expected interest rates have increased and economic growth has improved. He stated that these factors, taken in conjunction with his view that business risks have not diminished, support his recommendation for an increased approved ROE.[264]

187. Mr. Coyne considered global economic growth to be about the same as in the 2016 GCOC proceeding and on a stable trend.[265] The Fed's and the Bank of Canada's key interest rates are on an upward trend, and the yields on long-term government bonds have increased since 2016 and are expected to increase further.[266]

188. Dr. Cleary summarized his views as follows:

> Both Canada and Alberta are expected to experience more moderate but solid GDP growth going forward. Bond yield spreads have declined, as has stock market volatility, and both bond and stock markets are healthy. In other words, economic and capital market conditions are solid today, improved since 2016, and far removed from those existing at the peak of the 2008-2009 financial crisis.[267]

189. Mr. Thygesen's view was that virtually all risk measures are lower than they were in the 2016 GCOC proceeding, including the VIX and VIXC, which are basically half the levels of 2016. Further, his view was that utility spreads have decreased substantially since the period, which is consistent with the lower risk measures.[268]

### 6.7 Commission findings

190. In Decision 20622-D01-2016, the Commission found that the global and Canadian economic capital market conditions present at that time were different from the conditions that existed during the global financial crisis of 2008-2009, but there were still lingering effects of the global financial crisis.[269] Further, the Commission found that economic conditions were generally expected to improve in 2017, including an expected increase in interest rates and utility bond yields. The Commission also recognized that credit spreads had widened and market volatility was elevated compared to the 2013 GCOC proceeding.[270] Given all of the evidence, the Commission found that an increase in approved ROE was warranted for 2017.[271]

191. In the current proceeding, the Commission observes that Canadian actual real GDP for 2016 and 2017 was 1.4 and 3.0 per cent, respectively;[272] inflation and interest rates have risen in 2017, while utility bond yields remain effectively unchanged since the 2016 GCOC proceeding.

192. Based on this and other evidence filed on this proceeding, the Commission finds that the global economic and Canadian capital market conditions have improved since the time of the 2016 GCOC proceeding.

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264 Exhibit 22570-X0153.01, PDF page 10.
265 Transcript, Volume 5, page 905.
266 Transcript, Volume 5, page 909.
267 Exhibit 22570-X0562.01, PDF page 5.
268 Exhibit 22570-X0551, PDF page 5.
269 Decision 20622-D01-2016, paragraph 81.
270 Decision 20622-D01-2016, paragraphs 86, 89-90, 150-151.
271 Decision 20622-D01-2016, paragraph 337.
272 Exhibit 22570-X0749, PDF page 104.

193. A recent speech by a Bank of Canada deputy governor filed on the record by Mr. Buttke provides a succinct summarization of the current global economic and Canadian capital market conditions: "Canada is a very open economy, and its growth is supported by what is now a synchronous global expansion. We are now seeing solid growth not only in the United States and China but also in Europe, as well as in many other emerging-market economies."[273] Therefore, the Commission agrees with Dr. Cleary who expressed the view that economic and capital market conditions are "far removed from those existing at the peak of the 2008-2009 financial crisis."[274]

194. Looking forward, the Commission was presented with forecasts of Canadian economic growth, including projections by the Bank of Canada, that indicate slowing economic growth, with rates of 2.1 per cent in 2018 and 1.5 per cent in 2019.[275] Inflation is broadly expected to be near the Bank of Canada's target rate of two per cent over this same period.[276]

195. However, the Commission recognizes that future growth expectations are far from certain and are dependent on many factors, both domestic and international. Stated in reference to market volatility, ATCO and AltaGas argued that "the Commission should give weight to the Bank's [Bank of Canada] longer-term view of increased volatility expectations."[277]

196. A strong example of market uncertainty present during this proceeding that may cause both short-term and long-term volatility is the uncertain outcome of NAFTA negotiations. On this, the Commission finds the Bank of Canada's view, useful:

> … uncertainty about the North American Free Trade Agreement (NAFTA) and growing global trade tensions will need to be watched, for their possible impact on the outlook. Recent developments with respect to steel and aluminum, alongside increased protectionist rhetoric, carry potentially serious consequences. We do not know how or when the NAFTA talks or other trade disputes will conclude, and we do not know how industries, or governments, will react. The range of possibilities is wide, which means that trying to quantify any scenario in advance would not be useful for monetary policy purposes. For now, our working assumption is that existing trade arrangements will stay in place over our current two-year projection horizon. As and when concrete outcomes emerge, we will be in a better position to assess their impact on the Canadian economy.[278]

197. The Commission shares the broadly held view that the current proceeding was during a period of rising short-term interest rates.[279] It is readily observable that the Bank of Canada and the Fed were raising their policy interest rates, with the Bank of Canada having done so three times and the Fed having done so five times between the 2016 GCOC proceeding and the close

273 Exhibit 22570-X0823.
274 Exhibit 22570-X0562.01, PDF page 5.
275 Exhibit 22570-X0562.01, PDF page 19.
276 Exhibit 22570-X0562.01, PDF page 20. Exhibit 22570-X0918, paragraphs 33 and 54. Exhibit 22570-X0909, paragraph 79.
277 Exhibit 22570-X0900, paragraph 25.
278 Exhibit 22570-X0823, PDF page 6.
279 Transcript, Volume 3, page 575. Transcript, Volume 5, page 909. Transcript, Volume 6, page 1159. Transcript, Volume 10, pages 2071-2080.

of record for this proceeding. At the close of record for this proceeding, additional rate increases were expected in the remainder of 2018.[280]

198. What is not as readily transparent is how these rising short-term interest rates should impact the Commission's determinations in setting the 2018 to 2020 ROE. As Dr. Cleary pointed out, central bank policy interest rates only tend to affect the "short end" of the yield curve[281] (Figure 1). The Commission observes that the yield curve is "flattening," as in, the "long end" of the yield curve, or the yield on 30-year GOC bonds has not increased to the same degree as short-term interest rates since the 2016 GCOC proceeding (figures 1 and 2).

199. Using information filed on the record of this proceeding, the Commission has plotted the recent movements of the 10-year and 30-year GOC bonds and the 30-year utility bond yields in Figure 7 and notes the following:

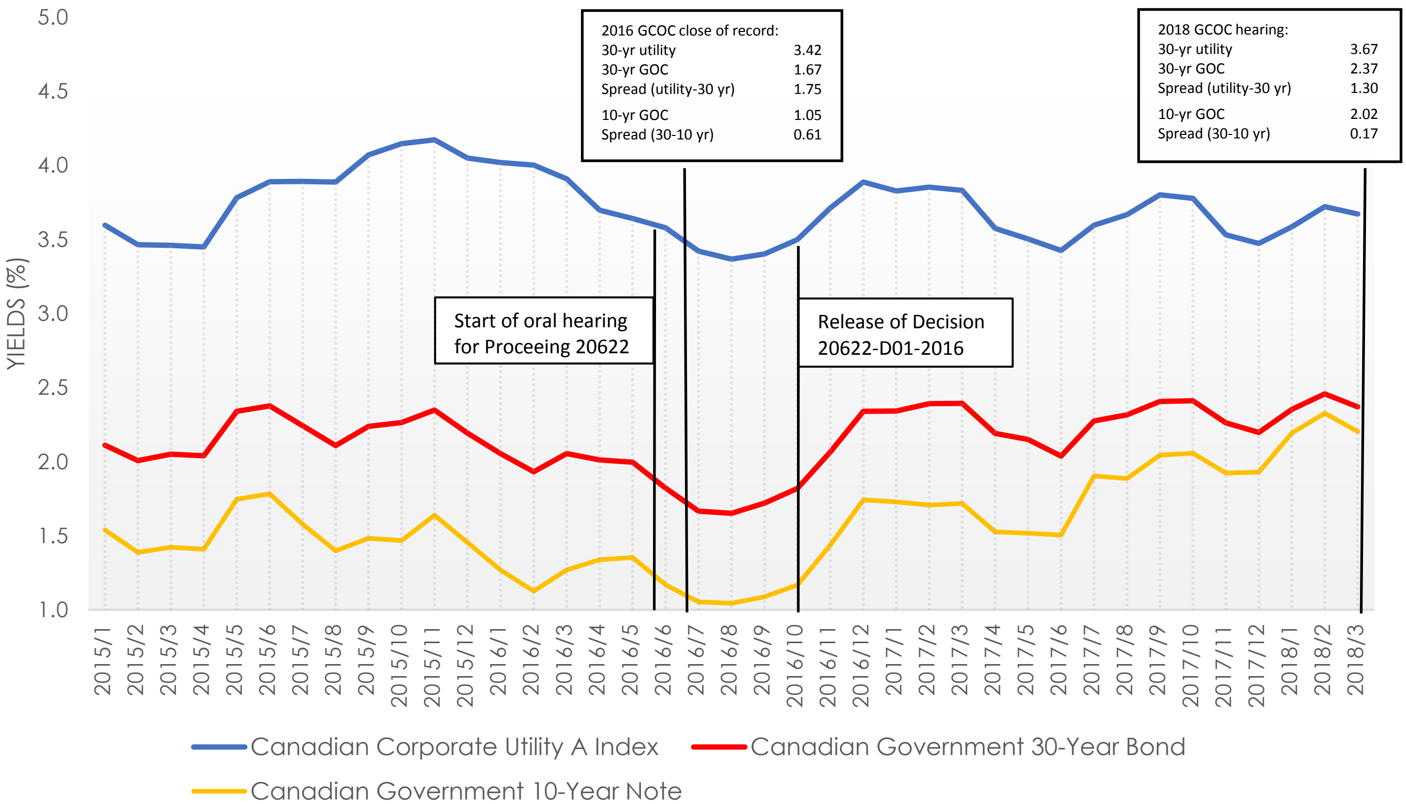
- The 30-year GOC bond yields have not increased to the same extent as the 10-year GOC bond yields and the spread between them has contracted to 17 bps at the time of the hearing for this proceeding, compared to the long-run historical average of approximately 50 bps.

- While the 30-year GOC bond yields have increased slightly since the close of record for the 2016 GCOC proceeding, when considering their movement over the last three years, they are generally unchanged.

- The 30-year utility bond yields have stayed in the range of those present during the 2016 GCOC proceeding. This has had the effect that credit spreads between 30-year utility bond yields and 30-year GOC bond yields have decreased from 179 bps at the time of the hearing for the 2016 GCOC proceeding to 130 bps at the time of the hearing for this proceeding.

[280] Transcript, Volume 3, page 561. Transcript, Volume 5, page 909. Transcript, Volume 6, page 1155. Transcript, Volume 10, pages 2071-2072.
[281] Transcript, Volume 6, page 1160.

**Figure 7 10-year, 30-year GOC bonds and the 30-year utility bond yields**[282]




200. During the current proceeding, the Commission was presented with different views with respect to what constitutes the “normal” credit spread and witnesses’ expectations on how the credit spread will change directionally over this GCOC term. Without engaging in the debate as to what constitutes the normal level for credit spreads (100 bps according to Dr. Cleary and Dr. Villadsen, or 130 bps according to Mr. Coyne and Mr. Hevert), the Commission continues to hold the view that credit spreads at the time of the 2016 GCOC proceeding were elevated compared to any level considered normal. Since the 2016 GCOC proceeding, credit spreads have narrowed significantly.

201. The Commission continues to be of the view that credit spreads are an objective measure, based on observable market data, which help to inform the Commission about utility bond investors’ risk perceptions, and by implication, to some extent, the expectations of utility equity investors. While evidence was put forward by Mr. Hevert that a decline in credit spreads may be of a short-term, temporary nature, and may not be indicative of a change in risk perceptions in the market,[283] the Commission is not persuaded by this evidence, which is contradicted by his own claims during the 2016 GCOC proceeding that the increase in credit spreads at that time demonstrated an increase in investors’ risk perceptions.[284]

282 Underlying data taken from Exhibit 22570-X0836.
283 Exhibit 22570-X0741, PDF pages 14-18.
284 Decision 20622-D01-2016, paragraph 64.

202. As further discussed in Section 8.3 of this decision, Dr. Cleary,[285] Mr. Hevert and Mr. Coyne presented evidence showing a negative correlation between changes in government yields and yield spreads, and that they tend to offset one another to a certain extent. With respect to future interest rates, witnesses provided evidence that 30-year GOC bond yields are generally expected to increase;[286] however, the Commission shares Dr. Cleary's view that "this is far from a given fact,"[287] as exhibited by the "flattening" yield curve (Figure 1). In contrast, witnesses filed less evidence on future expectations for 30-year utility bonds, which were near five-year lows (Figure 3). Given all the variables that may affect credits spreads and the disparate views held by witnesses on future expectations, the Commission is not able to arrive at a conclusion regarding how credit spreads will move directionally over the 2018-2020 period, other than they will likely militate any move in the underlying 30-year GOC bond yield.

203. In the 2016 GCOC proceeding, the Commission was presented with evidence that estimators of investor perceptions of near-term market uncertainty, particularly the VIX and the VIXC, were indicative of increased investor uncertainty in the 2016-2017 period compared to investor uncertainty which existed at the time of the 2013 GCOC proceeding.[288] The VIX and VIXC were presented during the current proceeding, along with additional estimators of investor perceptions that were not before the Commission in the 2016 GCOC proceeding.

204. The Commission accepted the VIX and VIXC as estimators of investor perceptions of volatility and gave them weight in determining the level of market volatility in the 2016 GCOC proceeding,[289] and no party has satisfied the Commission that anything has changed since the 2016 GCOC proceeding to depart from this.

205. The Commission observes that, based on Figure 6, the VIX and VIXC were relatively stable at or below longer-term averages since the 2016 GCOC proceeding, apart from a temporary spike in February 2018. The Commission is of the view that while some amount of volatility will always exist in the market, the level of volatility is lower than at the time of the 2016 GCOC proceeding. However, given that the VIX and VIXC are short-term measures of volatility, they do not necessarily provide an indication of investor uncertainty for 2019 and 2020.

206. In conclusion, the Commission finds that the global economic and Canadian capital market conditions have improved since the 2016 GCOC proceeding, and are far removed from the 2008-2009 financial crisis. In particular, the Commission observes that there has been 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, as will be discussed in the sections that follow, the Commission finds that the upward pressure associated with certain of these factors is largely offset by the downward pressure associated with others. On balance, these

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285 Exhibit 22570-X0562.01, PDF page 27.

286 Exhibit 22570-X0179, PDF page 59. Transcript, Volume 3, pages 574-575. Exhibit 22570-X0193.01, PDF page 23. Exhibit 22570-X0131, PDF page 28. Transcript, Volume 5, page 933. Exhibit 22570-X0153.01, PDF page 10. Transcript, Volume 6, pages 1159-1160. Exhibit 22570-X0562.01, PDF page 22. Transcript, Volume 10, pages 2076-2077.

287 Exhibit 22570-X0562.01, PDF page 25.

288 Decision 20622-D01-2016, paragraphs 90-91.

289 Decision 20622-D01-2016, paragraph 91.

factors indicate the approved ROE for 2018 should be at or near that set in the 2016 GCOC decision.

207. The Commission has also considered the evidence filed on the record of this proceeding with respect to future expectations for global economic and Canadian capital market conditions. Given the expectations of diminishing national GDP growth rates, moderately higher inflation to reach the mid-point of the Bank of Canada's target range, increasing short-term interest rates, a flattening yield curve, but uncertain long-term interest rates and market uncertainty with respect to international trade, the Commission finds that these factors result in a similar offset and together indicate that the approved ROE for 2019 and 2020 should be the same or similar to the value set for 2018.

## 7 Municipally owned utilities

208. In its July 5, 2017 correspondence, the Commission indicated that it intended to explore a number of issues in relation to municipally owned utilities in this proceeding:

> 36. … the Commission considers that the 2018 GCOC proceeding is also a forum to consider matters with respect to the municipally owned utilities, specifically. The Commission wishes to explore how their ownership structure and the relationship between the utilities' ratepayers and the municipality's taxpayers may affect ROE and deemed equity ratios for these utilities. In this regard, the Commission invites submissions from parties regarding what municipal ownership entails with regard to debt availability through the Alberta Capital Financing Authority (ACFA), credit metrics in light of available debt through ACFA, income tax status, the opportunity for municipal riders and the effect of these factors on the risk profile of the municipally owned utilities.[290]

209. In this section, the Commission will address generally the interplay between ownership structure and the stand-alone principle as it relates to municipally owned utilities, more specifically the role of ACFA funding in assessing the credit metrics of ENMAX and EPCOR given the stand-alone principle, and finally the use of equity funding riders. The Commission has addressed the issue of a utility's taxable status in relation to capital structure in Section 8.

### 7.1 Ownership structure and stand-alone principle

210. Both EPCOR and ENMAX are municipally owned corporations. EPCOR's ultimate owner, through its parent EPCOR Utilities Inc. (EUI), is the City of Edmonton.[291] ENMAX is wholly owned by ENMAX Corporation which, in turn, is wholly owned by Calgary.[292] Both EPCOR and ENMAX provided evidence and argument on the issues identified by the Commission, as noted above. While Red Deer and Lethbridge also operate municipal electric utilities, neither operate the utility as a separate corporate entity nor did either raise considerations with respect to the stand-alone principle in this proceeding. ENMAX submitted that the ownership structure of a municipal utility, and the relationship between the utility's ratepayers and the municipality's taxpayers, is not a relevant consideration in determining the

290 Exhibit 22570-X0114.
291 Exhibit 22570-X0195, paragraph 4.
292 Exhibit 22570-X0129, paragraph 4.

cost of capital of a municipally owned utility. It stated that municipally owned utilities must be regulated on a stand-alone basis.[293]

211. Mr. Coyne referred to the stand-alone principle for guidance on this issue. He submitted the stand-alone principle dictates that it is the use for the capital that a cost is applied to, and not the source.[294]

212. EPCOR stated that Standard & Poor's (S&P) and DBRS Limited (DBRS) have each addressed EUI's municipal ownership in recent credit-rating reports. DBRS commented that EUI's ownership structure limits its ability to access equity markets directly. S&P commented that there is a low likelihood that the City of Edmonton would provide timely and sufficient extraordinary support in the event that EUI faces financial distress. S&P added that if EUI required long-term support in a financial stress scenario, its belief is that EUI would more likely be sold than receive taxpayer support.[295]

213. EPCOR added that EUI was originally established in 1996 as a fully independent, stand-alone subsidiary corporation, and that the City of Edmonton limits its activities in relation to EUI to that of a shareholder. EUI is governed and managed independently of the City of Edmonton.[296]

214. EPCOR submitted that the stand-alone principle is fundamental in utility regulation, and requires that, regardless of who the owner of a utility happens to be, the ROE for that utility must be established based on what is necessary to attract investment in that utility, having regard for the risk of the utility on a stand-alone basis.[297] ENMAX expressed a similar view, and submitted that failure to apply the stand-alone principle can result in improper cross-subsidization.[298]

215. The UCA indicated that the City of Edmonton appoints EPCOR's board of directors and external auditors, approves the dividends the City of Edmonton receives from EUI through the dividend policy, and approves any material asset dispositions. It stated that the City of Edmonton is undoubtedly involved in the business operations of EPCOR.[299]

216. In argument, the CCA noted that both Mr. Madsen and Mr. Thygesen agree that the fair return should reflect the risk of the business itself and not the source of the financing.[300] Mr. Madsen also expressed the view, however, that the stand-alone principle should not be applied "by rote" if a decision causes harm to ratepayers or otherwise is not in the public interest.[301]

**Commission findings**

217. The stand-alone principle has been applied by the Commission to treat a regulated utility as a distinct entity for the purposes of determining the costs to be borne by ratepayers for the service of the regulated utility. As noted by the Alberta Court of Appeal in *ATCO Electric Ltd.*

293 Exhibit 22570-X0896, paragraph 142.
294 Transcript, Volume 5, page 997.
295 Exhibit 22570-X0195, paragraphs 55-57.
296 Exhibit 22570-X0195, paragraphs 36-38.
297 Exhibit 22570-X0195, paragraph 39.
298 Exhibit 22570-X0896, paragraphs 20-22.
299 Exhibit 22570-X0767.01, paragraph 330.
300 Exhibit 22570-X0888, paragraph 384.
301 Exhibit 22570-X0888, paragraph 382.

*v Alberta (Energy and Utilities Board)*, "The purpose of the stand-alone principle is to notionally isolate and categorize – for accounting and rate-making purposes – the costs incurred in the operation of a discrete business function of a utility."[302] The principle has been applied to allocate costs between regulated and non-regulated activities of an integrated utility, with the theory being that regulated utility customers should only pay for the costs of the regulated service. It has also been applied to allocate costs incurred by an integrated utility amongst its various business functions, so that just and reasonable rates can be set for each business function. In the context of a GCOC proceeding, the stand-alone principle has been applied to determine an ROE and deemed equity structure for each regulated utility as if it were a stand-alone entity.

218. The stand-alone principle arises with respect to municipal utilities when the Commission considers what regard, if any, should be had for the fact that the utility is ultimately owned by a municipality. A municipality possesses certain unique traits that distinguish it from a non-municipal corporation. For example, a municipality has access to low cost ACFA financing and the ability to use an equity funding rider, which it may pass on to the regulated utility. Additionally, a municipally owned utility is exempt from paying income taxes.

219. In some cases, the unique trait(s) of the municipality ultimately flow through to ratepayers. For example, Calgary makes ACFA financing available to ENMAX, and ratepayers benefit from ENMAX obtaining financing at lower interest rates than what it could procure itself.

220. In other cases, the unique features that may be associated with municipal ownership are not made available to the municipally owned utility and thereby do not flow through to ratepayers. In contrast to Calgary's practice for ENMAX, the City of Edmonton does not make ACFA financing available to EPCOR. Accordingly, in the case of EPCOR, ratepayers pay for financing at higher interest rates than what would be paid if EPCOR obtained ACFA financing. In approving EPCOR's debt financing costs in the past, the Commission has generally been persuaded to apply the stand-alone principle and considered the cost of debt for each of EPCOR transmission and EPCOR distribution as if they were distinct corporate entities. This issue is not without contention, and has been the subject of dispute amongst parties and considerable scrutiny by the Commission in past tariff proceedings.

221. In considering the application of the stand-alone principle in this proceeding, the Commission does not accept the submissions of those parties or witnesses who would have the Commission rigidly apply this principle. To do so would be inconsistent with past consideration and application of the stand-alone principle. For example, as noted by the Alberta Court of Appeal in *ATCO Electric Ltd. v Alberta (Energy and Utilities Board)*:

> [178] I also note that the evidence of the Independent Financial Experts to the Board, Messrs. Demcoe and McCormick (collectively the "IFE"), supports the Board's approach. The IFE testified that the stand-alone principle was developed as a shield to protect customers from higher rates due to subsidization of non-regulated activities. Therefore, in the IFE's view, it ought not to be used as a sword to require customers to pay higher rates simply because of a notional separation of what remained as integrated business functions. The IFE also argued that the stand-alone principle did not reflect the reality of how a utility accessed the capital market. When a utility sought financing, this

[302] *ATCO Electric Ltd. v Alberta (Energy and Utilities Board)*, 2004 ABCA 215, paragraph 175.

was not done on behalf of some discrete business function in the organization but rather on behalf of the larger corporate entity itself. For these reasons, the IFE concluded that:

> ... the Board should "not apply the stand-alone principle by rote. Instead the Board should deal with the reality, utilize independence of thought, question assumptions and think through whether an approach that has been applied in the past in different circumstances should be applied now in new circumstances. Such an approach should lead the Board to deal with reality and to decline to apply the stand-alone principle to the detriment of the customers of the [distribution companies]

[179] This is precisely what the Board did. It fully considered a number of separate issues affecting calculation of carrying costs and examined the business risk elements inherent in that calculation. Its conclusion was that the business risks, including the capital recovery risks, associated with the administration of the deferral accounts were, by their nature, very low: Decision 2001-92 at p.46, AB Vol. II, F127. Further, that risk was "significantly lower than the business risk of any of the three business functions" of an integrated utility… Thus, the Board decided that it would be fair and reasonable to consider the deferral accounts operation as a separate stand-alone business unit but within the totality of the integrated electric utility as it existed in the year 2000. The Board recognized that if this were not done, and the deferral accounts operation were treated purely as a stand-alone business as more than one party had urged at hearing, this would have "likely led to a windfall for the integrated utility." The Board also noted, correctly in my view, that while prudent costs does not mean the lowest possible costs "financing costs that are unnecessary and inflated, or alternatively, result in windfall profits to the utility cannot be considered prudent." These are conclusions which the Board was entitled to reach on this evidentiary record – and they are conclusions which weigh heavily in favour of the reasonableness of the Board's approach.

[180] More fundamentally, though, the question of what financial model to use in calculating carrying costs of a particular business function of a utility's operations is precisely the kind of issue which the Legislature intended to leave to the Board's discretion. As noted, an important feature of this analysis is the determination of the level of business and financial risk associated with a particular function. The fact a utility chooses to order its affairs in a particular fashion for internal purposes does not immunize it from Board scrutiny to determine what a fair and appropriate allocation of financing costs would be for a specific business function regardless of how the utility has structured its operations.

[181] Nor can a utility complain where the Board recognizes that some aspects of an integrated utility's business functions are less risky than others – and calculates financing costs accordingly. The Board is under no obligation to use an integrated utility's highest risk functions as the basis for setting the capital requirements of its lowest risk functions. That would be to ignore commercial realities. Thus, the Board has the jurisdiction to segregate business functions of an integrated utility – and determine a notional corporate organizational model – for purposes of evaluating risk and calculating prudent carrying costs associated therewith.[303]

222. While the Commission has generally maintained its practice of determining a deemed equity ratio for each utility that, when combined with the approved ROE, will achieve target

[303] *ATCO Electric Ltd. v Alberta (Energy and Utilities Board), 2004 ABCA 215,* paragraphs 178-181.

credit ratings in the A-range when assessed on a stand-alone basis, it has tempered this approach when it has determined, based on the evidence before it, that ignoring the utility's owner (or investor) would be inconsistent with other considerations, such as the Commission's obligation to ensure rates are just and reasonable. Put another way, while the Commission continues to apply the stand-alone principle, this is just one tool to assist it in determining a fair return and approving just and reasonable rates, as detailed in the fair return section above.

223. The Commission identified issues with respect to municipal ownership, such as debt availability through ACFA and the impact of ACFA on credit metrics, the opportunity for municipal riders and the effect of these factors on the risk profile of the municipally owned utilities, as matters to be considered in this proceeding, and the Commission discusses its findings on these specific issues below. In so doing, the Commission has balanced the application of the stand-alone principle, as discussed above, with other considerations, including the fair return standard and the Commission's overall obligation to ensure that rates are just and reasonable.

### 7.2 ACFA funding, credit metrics and stand-alone principle

224. The City of Edmonton and Calgary each have access to funding from ACFA, which is low cost debt based on the Province of Alberta's credit rating.[304] Calgary makes funding from ACFA available to ENMAX, and low cost debt from ACFA is passed on to ENMAX customers.[305] The City of Edmonton does not make funding from ACFA available to EPCOR.

225. EPCOR noted that the issue of availability of ACFA financing has arisen before the Commission or its predecessor on at least three occasions over the last decade. It noted that on two of these occasions, the Commission directed EPCOR to approach the City of Edmonton and inquire as to whether Edmonton would make funding from ACFA available to EPCOR. The City of Edmonton declined to make funding from ACFA available to EPCOR. EPCOR submitted that, in all cases, the Commission honoured the stand-alone principle and refused to deem EPCOR's approved debt rates at the ACFA rates.[306] EPCOR stated that the evidence is uncontroverted that it cannot access ACFA financing.[307]

226. Mr. Hevert submitted that because EPCOR cannot access ACFA financing, any issues related to credit metrics and the risk profile arising from the use of such funding are moot. He stated that even if such financing was available, this would not affect the risk of EPCOR's operations, or the return required on its equity.[308]

227. Mr. Coyne explained that while ENMAX may access funding from ACFA, the availability of this funding is at the discretion of Calgary. As a result, Mr. Coyne submitted that

304 See, for example, Exhibit 22570-X0195, at paragraph 43, citing Decision 2006-054: EPCOR Transmission Inc., 2005/2006 Transmission Facility Owner Tariff, EPCOR Distribution Inc., 2005/2006 Distribution Tariff – Phase I, Applications 1389884-1 and 1389885-1, June 15, 2006.
305 Exhibit 22570-X0129, paragraphs 4, 9.
306 Exhibit 22570-X0195, paragraph 41.
307 Exhibit 22570-X0195, paragraph 52.
308 Exhibit 22570-X0153.01, PDF page 128.

funding from ACFA should not be factored into the cost of equity determination for ENMAX on a stand-alone basis.[309]

228. In argument, the CCA did not advocate for asymmetrical application of the stand-alone principle, submitting:

> If a utility avails itself of ACFA funding (ENMAX) and that funding results in improved credit metrics, the Commission should not award that utility a lesser equity thickness simply on the basis of the improved credit metrics resulting from the use of ACFA funding. Similarly, if a utility does not avail itself of ACFA funding (EDTI), and yet that utility has depressed credit metrics as a result, the Commission should not award that utility additional equity thickness simply on the basis of the weakened credit metrics resulting from not using ACFA funding. The CCA does not view this as an asymmetric application of the stand-alone principles. In both cases the effects of the ACFA funding are ignored when approving an equity thickness.[310]

229. Mr. Madsen submitted that EPCOR's shareholder has decided not to use ACFA funding, and the result is that EPCOR has higher long-term debt rates and weaker credit metrics. He submitted that the Commission should consider requiring any future long-term debt issued by EPCOR to be deemed at the ACFA rate, for revenue requirement purposes and for the purpose of calculating credit metrics as part of GCOC proceedings.[311]

230. Mr. Thygesen submitted that the Commission should use the ACFA funding rates as the deemed rate for EPCOR's debt, even if EPCOR does not have access to such funding. He also stated that any credit metric calculations for EPCOR should be done with the assumption that its debt is funded through ACFA.[312] Mr. Thygesen took note of Decision 2008-100[313] in which the Commission stated, "With respect to a stand alone utility, the directors and management have responsibilities to ratepayers that include the following: … Accessing the lowest cost financing at the best terms available to finance utility operations …"[314] He submitted that it is clear that the City of Edmonton and EUI are not accessing the lowest cost financing at the best terms available for EPCOR, because the lowest cost financing would be funding from ACFA, which is contrary to the Commission's direction in Decision 2008-100.[315]

231. EPCOR contended that the submissions of Mr. Madsen and Mr. Thygesen are outside the scope of this proceeding. It contended there is no principled basis for the availability of ACFA financing (or the lack thereof) to have any effect on EPCOR's ROE, deemed equity ratio, credit metrics or risk profile.[316]

232. EPCOR submitted that the evidence of Mr. Madsen and Mr. Thygesen is entirely at odds with the stand-alone principle. It argued that while Mr. Thygesen purports to rely on previous Commission findings relating to the stand-alone principle in another context in support of his

309 Exhibit 22570-X0131, PDF page 107.
310 Exhibit 22570-X0888, paragraph 381.
311 Exhibit 22570-X0557, paragraphs 212-213.
312 Exhibit 22570-X0551, paragraph 19.
313 Decision 2008-100: ATCO Electric Ltd. Stand Alone Study, Proceeding 18, Application 1562230-1, October 21, 2008.
314 Decision 2008-100, page 6.
315 Exhibit 22570-X0551, paragraphs 17-18.
316 Exhibit 22570-X0893, paragraph 76.

position, it is clear there is no reasonable basis to suggest that the stand-alone principle be abandoned in the present circumstances.[317] EPCOR noted Mr. Thygesen's submission during the oral hearing that, if the phrase about the owner accessing the lowest cost financing was not in Decision 2008-100, his view with respect to ENMAX and EPCOR would be that the stand-alone principle should be considered in order to meet the fair return standard.[318]

233. EPCOR submitted that the responsibility described in the phrase relied upon by Mr. Thygesen from Decision 2008-100 is not properly interpreted as an absolute obligation that overrides the stand-alone principle. It further indicated that the passage does not appear to have been treated by the Commission as an authoritative statement or principle noting that Decision 2008-100 was not applied by the Commission in the context of addressing the ACFA financing issue with respect to EPCOR in decisions that were issued subsequent to Decision 2008-100.[319]

234. EPCOR submitted that the duty of a utility to access the lowest cost financing at the best terms available to finance utility operations is inconsistent with a previous observation of the Commission that historically, the least cost approach has not necessarily been accepted when assessing the prudence of utility costs.[320]

235. Mr. Bell stated that it is both unfair and unreasonable for a shareholder, who seeks to maximize its ROE from a regulated utility, not to seek to minimize borrowing costs to the utility when it had an opportunity to do so.[321] The UCA submitted that any reasonable and prudent shareholder should absolutely look to secure the lowest financing available to its company in the marketplace.[322]

236. The UCA submitted that the Commission can and should decline to apply the stand-alone principle by rote and should decline to apply the stand-alone principle to the detriment of customers. It indicated that customers are paying an additional $6 million per year as a result of EPCOR not accessing ACFA financing. The UCA stated that in the circumstances, it is both reasonable and fair that the Commission deem ACFA funding rates for EPCOR's debt.[323]

**Commission findings**

237. The Commission agrees with the CCA's recommendation that "If a utility does not avail itself of ACFA funding (EDTI), and yet that utility has depressed credit metrics as a result, the Commission should not award that utility additional equity thickness simply on the basis of the weakened credit metrics resulting from not using ACFA funding."[324] In line with this finding, in Section 9 the Commission considers the City of Edmonton's refusal to make ACFA financing available to EPCOR in its consideration of EPCOR's credit metrics for the purposes of assessing the capital structure necessary to provide EPCOR with a fair return.

317 Exhibit 22570-X0733, A42.
318 Transcript, Volume 8, page 1699.
319 Exhibit 22570-X0893, paragraphs 109-110.
320 Exhibit 22570-X0893, paragraph 111.
321 Exhibit 22570-0675, UCA-AUC-2018JAN26-029.
322 Exhibit 22570-X0767.01, paragraph 324.
323 Exhibit 22570-X0913, paragraph 188.
324 Exhibit 22570-X0888, paragraph 381.

238. With respect to EPCOR's cost of debt and whether it should be deemed at ACFA rates, the Commission finds that this issue is best determined in a general tariff application (GTA) or other rate-related proceeding. Accordingly, concerns advanced by interveners in this proceeding with respect to EPCOR's cost of debt being higher than necessary given that its parent has access to ACFA financing will not be addressed in this decision.

### 7.3 Use of equity funding riders

239. ENMAX provided the following summary of equity funding riders:

> Section 138 of the *Electric Utilities Act* states that a municipality may impose amounts in respect of its electric distribution system that are in addition to the rates approved by the Commission, if the bills submitted to customers (a) clearly distinguish between the rates approved by the Commission and the additional amounts imposed by the municipality, and (b) identify the additional amounts imposed by the municipality as a surcharge or tax.[325]

240. ENMAX noted that historically, the Commission has treated any funds received through equity funding riders as no-cost capital, because this would mitigate any concerns about double recovery of investment and an unfair return on investment.[326] Mr. Coyne commented that because of this no-cost capital treatment, any equity funding riders should not enter into consideration when setting the approved ROE.

241. Similar to his submission on ACFA financing, Mr. Hevert submitted that because EPCOR does not use equity funding riders, any issues related to its risk profile arising from the use of equity funding riders are moot. He stated that even if such financing was available, empirical research indicates that the use of equity funding riders has no statistically significant effect on required return. Mr. Hevert stated that any use of an equity funding rider would have no effect on EPCOR's risk profile.[327]

242. EPCOR noted that the City of Edmonton has never used an equity funding rider for EPCOR, and EPCOR has never requested that the city do so.[328]

**Commission findings**

243. The Commission finds that the use of an equity funding rider, all else equal, may provide a municipally owned utility with additional cash flow and could provide a municipally owned utility with support that would not be available to a non-municipal regulated utility. However, given that neither Calgary nor the City of Edmonton impose an equity funding rider, the Commission does not consider it necessary to address this matter any further at this time. The Commission may revisit the impact and treatment of equity funding riders in a future proceeding if equity funding riders are implemented.

[325] Exhibit 22570-X0129, paragraph 13.
[326] Exhibit 22570-X0129, paragraphs 14-15.
[327] Exhibit 22570-X0153.01, PDF pages 128-130.
[328] Exhibit 22570-X0195, paragraph 54.

# 8 Return on equity

244. A GCOC proceeding establishes the deemed return on equity for the purposes of setting regulated rates for a future period; in this case, for 2018, 2019 and 2020. Generally, the cost of equity to a firm is the return that investors require to make on equity investment in the firm. That is, investors will only provide funds if the ROE that they expect to receive is sufficient to compensate them for the risks they are assuming in making the investment. The approved cost of equity in the GCOC period is a point estimator of investor return expectations that reflects investors' return requirements over the long run. In reality, due to the long-term nature of equity returns, investors evaluate their equity investment both in the short term and the long term, as actual returns fluctuate over time.

245. The Commission received a significant body of evidence to assist it in determining a fair approved ROE, including a number of opinions on the proper methodology to be employed and a wide range of proposed ROEs, based on evidence on the current financial environment and the results of a number of models.

246. Dr. Cleary, Dr. Villadsen, Mr. Buttke, Mr. Coyne, Mr. Hevert and Mr. Thygesen provided evidence on changes in the global and Canadian financial environment since the conclusion of the 2016 GCOC proceeding. The Commission's findings on this evidence are set out in Section 6.7.

247. Dr. Cleary, Dr. Villadsen, Mr. Coyne and Mr. Hevert utilized the capital asset pricing model (CAPM). Dr. Villadsen and Mr. Hevert also employed the use of an empirical CAPM (ECAPM). The Commission's findings on the evidence relating to these models are set out in Section 8.2.4 and Section 8.2.5.

248. Dr. Cleary and Mr. Hevert used a bond yield plus risk premium model (BYPRPM). Mr. Hevert also utilized a predictive risk premium model. The Commission's findings with respect to these models are set out in Section 8.3.

249. Dr. Cleary, Dr. Villadsen, Mr. Coyne and Mr. Hevert submitted discounted cash flow (DCF) model estimates for utility equities, in order to estimate the required ROE for the affected utilities. Dr. Cleary and Mr. Hevert submitted DCF model estimates for the Canadian market as a whole, while Mr. Hevert also submitted a DCF model estimate for the U.S. market as a whole. The Commission's findings on the various DCF model results are set out in Section 8.4.

250. Dr. Cleary submitted evidence on the stock market return expectations of finance professionals. The Commission addresses this area in Section 8.5.

251. Dr. Villadsen presented information on the approved ROE for other Canadian and U.S. utilities for 2016 and 2017. Dr. Cleary presented evidence on the relevance of market price-to-book (P/B) values in assessing the cost of equity. The Commission's findings on this material are set out in Section 8.7.

252. Consistent with the approach adopted in previous GCOC decisions, in arriving at the fair approved return for the affected utilities, the Commission considered a variety of approaches, models and directional indices. The Commission summarizes its findings and sets out the approved ROE for 2018-2020 in Section 8.8.

253. In Section 8.9, the Commission considered its previous approach of using an annual adjustment formula for ROE and indicates its intention to explore the possibility of returning to a formula-based approach to cost of capital matters

## 8.1 Use of proxy group companies

254. Before the Commission begins its review of the evidence on the financial models employed by the various witnesses, it will comment on the use of data from proxy group companies. Dr. Villadsen explained the need for the use of this data, as follows.

> Since the Utilities [the ATCO Utilities and AltaGas] are subsidiaries of consolidated entities and do not themselves have publicly traded stock, it is not possible to directly estimate their cost of equity using the CAPM or DCF models. This is because these models rely on market information (such as stock prices, betas based on historical stock returns, and growth rate estimates) to estimate the expected returns required by equity investors.[329]
>
> ….
>
> That is why I develop samples of publicly traded companies that are as analogous as possible to the Utilities in terms of business risk, and apply the models to those samples as proxies for the Utilities.[330]

255. Mr. Coyne[331] and Mr. Hevert[332] echoed the views of Dr. Villadsen.

256. The Commission has previously commented on some of the challenges associated with determining the ROE for the affected utilities, because of the lack of direct market evidence.

> …the determination of the rate of return on equity for a regulated utility is difficult given that the correct answer is not readily apparent. This determination requires an expert tribunal to apply its judgment in assessing often conflicting evidence and to consider the differing interests and perspectives on risk of debt and equity investors. This exercise is made even more complex in Canada, and in Alberta in particular, given the limited number of stand-alone utilities issuing debt and the lack of any utilities that issue equity directly to investors. This fact which has partially resulted from deregulation and unbundling of utility services, corporate reorganizations creating utility holding companies, holding companies owning a mix of regulated and unregulated business and utility acquisitions was referred to in the oral hearing as interposing a “dirty window” between direct market evidence on cost of capital and the true cost of capital for Alberta utilities.[333]

257. Mr. Hevert developed two proxy groups. The first group, referred to as his Canadian utility proxy group, consists of six publicly traded Canadian utility companies.[334] Mr. Hevert’s second proxy group, referred to as his U.S. utility proxy group, consists of 25 publicly traded

329 Exhibit 22570-X0193.01, A39.
330 Exhibit 22570-X0193.01, A39.
331 Exhibit 22570-X0131, PDF page 33.
332 Exhibit 22570-X0153.01, PDF page 44.
333 Decision 2009-216, paragraph 110.
334 Exhibit 22570-X0153.01, Table 2.

U.S. companies[335] that form part of the universe of companies classified by Value Line as electric utilities.[336]

258. Mr. Coyne developed three proxy groups. The first group, referred to as his Canadian utility proxy group, consists of five publicly traded Canadian utility companies.[337] The second proxy group selected by Mr. Coyne, referred to as his U.S. electric proxy group, consists of 11 publicly traded U.S. companies[338] that form part of the universe of companies classified by Value Line as electric utilities.[339] Mr. Coyne suggested that these 11 companies would be considered by investors as comparable in risk to Alberta's electric utilities.[340] Mr. Coyne's third proxy group, referred to as his North American electric proxy group, consists of the 11 companies from his U.S. electric proxy group, and three companies from his Canadian utility proxy group. Mr. Coyne indicated that the three Canadian companies included in his third proxy group are primarily engaged in the provision of electricity.[341]

259. Dr. Villadsen developed five main proxy groups, and she further developed subsample proxy groups within three of those main proxy groups. Dr. Villadsen's first proxy group, referred to as her Canadian utility proxy group, consists of nine Canadian publicly traded companies[342] that have utility operations in Canadian regulatory jurisdictions.[343] Dr. Villadsen's second proxy group, referred to as her U.S. electric utility proxy group, consists of 30 publicly traded U.S. companies,[344] whose primary source of revenues and majority of assets are in the regulated portion of the U.S. electricity industry.[345] Dr. Villadsen developed a subsample from within her second proxy group, referred to as her subsample U.S. electric utility proxy group. This subsample consists of 21 companies,[346] each of which has at least 80 per cent of their assets subject to regulation.[347]

260. Dr. Villadsen's third proxy group, referred to as her U.S. gas LDC (local distribution company) utility proxy group, consists of nine publicly traded U.S. companies[348] that have the majority of their revenue generating assets dedicated to the regulated distribution of natural gas in the U.S.[349] Dr. Villadsen developed a subsample from within her third proxy group, referred to as her subsample U.S. gas LDC utility proxy group. This subsample, which consists of six companies,[350] was developed in order to exclude three companies from her U.S. gas LDC utility proxy group that are the subject of major mergers and acquisitions.[351]

335 Exhibit 22570-X0153.01, Table 3.
336 Exhibit 22570-X0153.01, PDF page 45.
337 Exhibit 22570-X0131, Table 4.
338 Exhibit 22570-X0131, Table 5.
339 Exhibit 22570-X0131, PDF page 36.
340 Exhibit 22570-X0131, PDF page 36.
341 Exhibit 22570-X0131, PDF page 38.
342 Exhibit 22570-X0193.01, Figure 8.
343 Exhibit 22570-X0193.01, A41.
344 Exhibit 22570-X0193.01, Figure 9.
345 Exhibit 22570-X0193.01, A46.
346 Exhibit 22570-X0193.01, Figure 9.
347 Exhibit 22570-X0193.01, A43.
348 Exhibit 22570-X0193.01, Figure 10.
349 Exhibit 22570-X1093.01, A47.
350 Exhibit 22570-X0193.01, Figure 10.
351 Exhibit 22570-X1093.01, A47.

261. Dr. Villadsen's fourth proxy group, referred to as her U.S. water utility proxy group, consists of eight publicly traded U.S. companies,[352] whose primary source of revenues and majority of assets are subject to regulation.[353]

262. Dr. Villadsen's fifth proxy group, referred to as her U.S. pipeline proxy group, consists of six publicly traded U.S. companies[354] that operate primarily in the regulated transportation of natural gas, crude oil or petroleum products in the U.S.[355] Dr. Villadsen developed a subsample from within her fifth proxy group, referred to as her subsample U.S. pipeline proxy group. This subsample, which consists of three companies,[356] reflects the companies within the U.S. pipeline proxy group that have a higher proportion of regulated assets dedicated to pipeline transportation operations.[357]

263. Dr. Cleary utilized three proxy groups. His first proxy group, referred to as his nine company Canadian utility proxy group, consists of nine publicly traded Canadian utility companies.[358] Dr. Cleary's second proxy group, referred to as his seven company Canadian utility proxy group, is a subsample of his nine company proxy group, and consists of seven companies.[359] Dr. Cleary's seven company Canadian utility proxy group was developed in order to exclude two companies that are primarily non-regulated utilities.[360]

264. Dr. Cleary's third proxy group, referred to as his four company Canadian utility proxy group, is also a subsample of his nine company proxy group, and consists of four companies.[361] Dr. Cleary's four company Canadian utility proxy group was developed in order to exclude two companies that are primarily non-regulated utilities, to exclude two holding companies that include interests in non-regulated assets, and to exclude one company that has a mix of regulated and non-regulated assets.[362]

265. Based on some quantitative analysis, described in more detail in Section 9.3.3, Dr. Cleary submitted that U.S. holding companies are poor comparators for the affected utilities, because the U.S. utilities have "significantly higher business risk."[363] Given Dr. Cleary's view that there are significant issues with using U.S. companies as proxy groups, Dr. Cleary only used data from Canadian companies in his CAPM and DCF analysis.[364]

266. The UCA submitted there is substantial and compelling evidence to support disregarding and excluding U.S. proxy groups for the purposes of estimating the cost of equity. It further submitted that if the Commission does not agree that all the U.S. proxy groups should be

352 Exhibit 22570-X0193.01, Figure 11.
353 Exhibit 22570-X1093.01, A48.
354 Exhibit 22570-X0193.01, Figure 12.
355 Exhibit 22570-X1093.01, A49.
356 Exhibit 22570-X0193.01, Figure 12.
357 Exhibit 22570-X0193.01, A49.
358 Exhibit 22570-X0562.01, Table 8.
359 Exhibit 22570-X0562.01, Table 8.
360 Exhibit 22570-X0562.01, PDF page 46.
361 Exhibit 22570-X0562.01, Table 8.
362 Exhibit 22570-X0562.01, PDF page 47.
363 Exhibit 22570-X0562.01, PDF page 47.
364 Exhibit 22570-X0562.01, PDF page 92.

excluded, then Dr. Villadsen's U.S. pipeline proxy group and U.S. water utility proxy group should be specifically excluded.[365]

267. The UCA noted that the beta (β) of Dr. Villadsen's U.S. pipeline proxy group is 1.04, while Canadian utility betas do not approach 1.00.[366] The UCA suggested that Mr. Hevert and Mr. Coyne appeared to agree that the U.S. pipeline proxy group should be disregarded.[367] The UCA submitted that if the U.S. pipeline proxy group is not comparable, as acknowledged by Dr. Carpenter,[368] then it should not be used to draw conclusions as to the cost of equity, even as a directional indicator.[369]

268. AltaGas and the ATCO Utilities replied that despite Dr. Cleary's preference for focusing on regulated entities, the UCA wanted the Commission to exclude Dr. Villadsen's U.S. water utility proxy group. They pointed out that the average percentage of regulated assets for the U.S. water utility proxy group is 94 per cent, and Dr. Carpenter described this sample as "about as clean a pure play sample as you're going to find in the regulated utility space in North America."[370] AltaGas and the ATCO Utilities noted that Dr. Villadsen used her U.S. pipeline proxy group as an upper bound on the ROE, and her recommended ROE of 10 per cent is lower than the estimate for her U.S. pipeline proxy group.[371]

269. As discussed in more detail in Section 9.3.3, Mr. Coyne,[372] Dr. Carpenter and Dr. Villadsen[373] all considered that Dr. Cleary's quantitative-based conclusion that the U.S. utilities in the various proxy groups have significantly more business risk than the affected utilities was unsound. They submitted that Dr. Cleary had performed a flawed coefficient of variation (CV) analysis, and that if Dr. Cleary had performed the correct analysis, he would have found that U.S. utilities have lower volatility in operating profit margins.

**Commission findings**

270. The Commission acknowledges the challenges in choosing suitable publicly traded companies to serve as reasonable comparators to the affected utilities. This is compounded by the "dirty window" phenomenon as referenced in the above quote from paragraph 110 of the 2009 GCOC decision.

271. As discussed in Section 9.3.3, because of issues identified with Dr. Cleary's quantitative-based comparison of the business risks of the affected utilities and U.S. utilities,[374] the Commission is not convinced that there is substantial evidence on which to exclude the use of U.S. proxy groups.

365 Exhibit 22570-X0897.01, paragraphs 54-55.
366 Exhibit 22570-X0897.01, paragraphs 55-56.
367 Exhibit 22570-X0897.01, paragraphs 55-56.
368 Transcript, Volume 4, page 762.
369 Exhibit 22570-X0888, paragraph 58.
370 Transcript, Volume 1, page 169.
371 Exhibit 22570-X0918, paragraphs 119-122.
372 Exhibit 20622-X0909, PDF page 5.
373 Exhibit 20622-X0909, PDF page 5.
374 Exhibit 22570-X0775, PDF pages 49-51. Exhibit 22570-X0751, A18. Exhibit 22570-X0751, A20. Exhibit 22570-X0767.01, A19. Exhibit 22570-X0741.01, PDF pages 58-59.

272. Dr. Villadsen's U.S. pipeline proxy group received a lot of scrutiny as to its comparability to the affected utilities. Dr. Villadsen stated that she "excluded all my discounted cash flow numbers from the pipeline sample because they were very high."[375] Dr. Carpenter acknowledged that the U.S. pipeline proxy group was not comparable to the affected utilities, but considered it could provide useful information due to the method by which these companies are regulated.[376] Mr. Coyne considered this proxy group to be an outlier to be set aside, when questioned as to the magnitude of the range of beta estimates provided to the Commission in this proceeding range.[377]

273. The Commission agrees with the overall view that Dr. Villadsen's U.S. pipeline proxy group, and its subsample group, are not valid comparators for determining the approved ROE for the affected utilities. The Commission will therefore disregard any results from these proxy groups as part of its ROE analysis.

274. The Commission has reviewed the selection process followed by Dr. Cleary, Dr. Villadsen, Mr. Coyne and Mr. Hevert in arriving at each of their proxy groups. With the exception of Dr. Villadsen's U.S. pipeline proxy group and its subsample group, the Commission considers that the selection processes resulted in reasonable proxy groups for application of the ROE estimation models. Regarding Dr. Villadsen's U.S. water utility proxy group, the Commission finds that there is insufficient evidence to exclude this group, beyond Dr. Cleary's submission that he "simply did not feel it was a valid comparator sample."[378]

275. The Commission retains its view from the 2016 GCOC decision that although returns awarded by U.S. regulators cannot be used directly in determining a fair return for Alberta utilities, it is reasonable to consider the U.S. market returns data given the globalization of the world economy and integration of North American capital markets.[379] Accordingly, the Commission will consider the market-based results from both the Canadian and U.S. proxy groups in this decision, with the exception of the results from Dr. Villadsen's U.S. pipeline proxy group and its subsample group. Even though the Commission agrees that the proxy selection processes resulted in reasonable proxy groups for application in the ROE estimation models, the Commission is mindful of the "dirty window" problem, given that none of the affected utilities raise capital directly in the equity market. Accordingly, a significant amount of judgment by both witnesses and the Commission must be applied when interpreting this data to establish the ROE required by investors in the affected utilities.

## 8.2 The capital asset pricing model

276. The CAPM approach is broadly based on the principle that investors' compensation for the use of their capital must recognize two factors: their foregone time value of money, and any risk attendant in the investment. The time value of money is represented in CAPM by a component of the required rate of return that corresponds to a risk-free rate, which is intended to represent the return an investor would expect to receive for investing capital in a risk-free security over a comparable time period. The second part of CAPM incorporates an adjustment to the risk-free rate intended to reflect a premium required to address the return required to

375 Transcript, Volume 4, page 664.
376 Transcript, Volume 4, page 762.
377 Transcript, Volume 5, page 953.
378 Exhibit 22570-X0699, Cleary-ATCO/AUI-2018JAN26-014.
379 Decision 20622-D01-2016, PDF page 72.

compensate for the risk of beyond the risk-free rate, referred to as the market equity risk premium (MERP), and the beta, which is a measure of how sensitive the subject security's required return is relative to changes in overall market returns. Beta is usually derived from an examination of the past statistical relationship between historical returns for a given security and the returns of the overall capital market during the same time period. In this way, CAPM calculates the expected return for a security as the rate of return on a risk-free security plus a risk premium specific to that security or type of security. In other words, the CAPM formally assumes that all securities are priced such that the required return on the security is equal to the risk-free rate plus the security's beta risk measure times the difference between the required return on the overall market and the risk-free rate.

277. In general terms, CAPM can be represented by the following formula:

$$Re = Rf + \beta[E(Rm)-Rf],$$

where:

**Re** is the required return on common equity
**Rf** is the risk-free rate
**β**, or **beta**, measures the sensitivity of a required return of an individual security to changes in the market return
**E(Rm)-Rf** is the MERP; i.e., the expected market return E(Rm) minus the risk-free rate, Rf

278. Evidence supporting proposed ROEs based on an application of CAPM, or variations thereof, was provided by Mr. Hevert, Dr. Villadsen, Mr. Coyne and Dr. Cleary. As well, Mr. Thygesen and Mr. Johnson commented on some inputs to the CAPM recommendations presented in this proceeding. Each CAPM component, and the overall resulting CAPM estimates for ROE, are addressed in sections 8.2.1 to 8.2.5.

### 8.2.1 Risk-free rate

279. The CAPM analysis requires an estimate of the risk-free rate. As in previous GCOC proceedings, parties to this proceeding used yields on long-term government bonds as a proxy for the risk-free rate in their CAPM analyses.

280. Both Mr. Hevert and Dr. Cleary indicated that they used both the current and expected measures of the long-term government bond rate in developing their risk-free rate recommendations, consistent with the approach accepted by the Commission in previous GCOC decisions.

281. For his Canadian utility proxy group, Mr. Hevert used two estimates of the risk-free rate: the then-current 30-day average yield on 30-year Canada bonds of 2.37 per cent, as well as the 2018 projected 30-year Canada bond yield of 3.08 per cent from the Royal Bank of Canada (RBC) Economics Research Financial Markets Monthly. During the hearing, Mr. Hevert provided an updated RBC report showing that the yield on 30-year Government of Canada (GOC) bonds was expected to increase from 2.45 per cent at the start of 2018 to 3.30 per cent by

the end of 2019.[380] For his U.S. utility proxy group, Mr. Hevert used four estimates of the risk-free rate: the then-current 30-day average yield on 30-year Treasury bonds of 2.77 per cent; the 2018 projected 30-year Treasury yield of 3.33 per cent; the 2019 projected yield of 4.20 per cent; and the 2020 projected yield of 4.30 per cent obtained from the Blue Chip Financial forecasts.[381] Mr. Hevert explained that he preferred the RBC and Blue Chip Financial reports because they forecast 30-year government bond yields, whereas *Consensus Forecasts* by Consensus Economics provides forecasts for 10-year yields thus necessitating an additional adjustment.[382]

282. Mr. Johnson presented the RBC report from January 2018, showing the same projections as contained in Mr. Hevert's undertaking. Mr. Johnson also pointed out that at the time of the 2016 GCOC proceeding, "RBC was forecasting essentially the exact same 3.30% LTC [long-term Canada] yield two year's [*sic*] out as they are now."[383] As such, Mr. Johnson concluded that there has been no change in the forecast interest rate environment since 2014.

283. Dr. Cleary presented a risk-free rate range of 2.2 per cent to 3.0 per cent, with a mid-point of 2.6 per cent. The lower bound of 2.2 per cent represented the rounded-up actual prevailing long-term Canada yield as of December 2017 when Dr. Cleary prepared his evidence. The upper bound of 3.0 per cent was obtained by adding the long-term average spread between 10- and 30-year GOC bond yields of 50 basis points to the October 2017 Consensus Forecasts for GOC 10-year yields of 2.5 per cent for October 2018.[384] Dr. Villadsen and Mr. Coyne criticized Dr. Cleary's forecast horizon of October 2018 as being too short, given that this proceeding determines the cost of capital for 2018 to 2020.[385]

284. Dr. Villadsen expressed the view that because all indicators point to an increase in the cost of debt going forward, a forecast bond rate is more indicative of the cost of equity than the current rate. To develop her risk-free estimate, Dr. Villadsen relied on a forecast of the GOC bond yields in 2019, which is the middle year of the test period for this proceeding. Dr. Villadsen identified that the October 2017 *Consensus Forecasts* predicted the 10-year GOC bond yield to be 2.9 per cent by 2019. To that predicted yield she added 40 bps based on her estimate of the representative maturity premium for the 30-year over the 10-year GOC bonds, to arrive at a lower bound of her risk-free rate recommendation of 3.3 per cent. Dr. Villadsen also considered a scenario in which the risk-free interest rate was 3.45 per cent.[386]

285. Mr. Coyne expressed a similar preference for using forward-looking data rather than current risk-free rates. Relying on the October 2017 *Consensus Forecasts* data for predicted 10-year government bond yields for each of 2018, 2019 and 2020, Mr. Coyne calculated an average rate for the period of 2.83 per cent for Canada and 3.27 per cent for the U.S. After adding an average historical spread between 10- and 30-year government bond yields (43 bps for Canada and 59 bps for the U.S.), Mr. Coyne arrived at the long-term bond yields of 3.26 per cent for Canada and 3.95 per cent for the U.S.[387]

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380 Exhibit 22570-X0869.
381 Exhibit 22570-X0153.01, PDF pages 75-76.
382 Transcript, Volume 6, page 1183.
383 Exhibit 22570-X0611.02, PDF page 10.
384 Exhibit 20622-X0306, PDF page 31.
385 Exhibit 22570-X0767.01, PDF pages 29-30. Exhibit 22570-X0775, PDF page 24.
386 Exhibit 22570-X0193.01, PDF page 59.
387 Exhibit 22570-X0131, PDF page 47.

286. In his evidence for the CCA, Mr. Thygesen compared the interest rate predictions by *Consensus Forecasts* to the actual interest rates and stated that *Consensus Forecasts (*and other forecasts by banks and government bodies) "have consistently over-forecast the 10-year rate since 2008" and therefore exhibit "a strong bias towards over-forecasting."[388] As a result, Mr. Thygesen argued against relying solely on C*onsensus Forecasts*. In their respective arguments, the CCA and the UCA supported this view.[389]

287. Mr. Thygesen reiterated his recommendation from the 2016 GCOC proceeding that the Commission consider forward curve rates in developing its risk-free estimates; for example, by taking an average of the *Consensus Forecasts* and the forward curve rates. Mr. Thygesen acknowledged that the forward curve rates are not a forecast per se; however, they are based on market transactions and have had a smaller forecasting error as compared to Consensus Forecasts over the 2016-2017 period. Based on the utility witnesses' responses to the CCA IRs, Mr. Thygesen presented data indicating that forward curve rates for long-term GOC bond yields were in the 2.3 to 2.6 per cent range, with the majority of data points centered on the 2.3 per cent estimate.[390]

288. The utility witnesses disagreed with recommendations to assign less weight to interest rate forecasts. They indicated that Mr. Thygesen did not perform the statistical analysis required to demonstrate the presence of bias in economic forecasts. They also pointed out that the post-financial crisis period referenced by Mr. Thygesen, over which the forecasts were made, exhibited many unusual characteristics and, as a result, interest rate forecast accuracy was low during that period.[391]

289. Regarding the use of forward curve rates, Mr. Buttke stated that "forward curves have not been proven to be more accurate than forecasts in an academically robust way." He explained that the "unbiased expectations theory" underlies the premise that forward rates would provide an accurate forecast. In this regard, Mr. Buttke referenced a study by the Federal Reserve, which concluded that because "The expectations hypothesis of the term structure has been consistently and decisively rejected, for the United States at least, and so we should not expect to find that forward interest rates and interest rate futures are efficient forecasts of future interest rates."[392] Mr. Buttke also indicated that forward curve rates can be inaccurate because they reflect market equilibrium (including any market inefficiencies) for a set of facts that is known at a given moment. In other words, they project whatever is currently known into the future. Because of this, forward curve rates may be "especially poor at implying future prices when markets are changing level or direction – they almost always imply a continuation of current conditions and trends."[393] Mr. Buttke provided charts showing that forward curves "over predict" the status quo: in an interest rate market that has trended lower for a number of years, the forward curve

388 Exhibit 22570-X0551, PDF pages 9 and 11.
389 Exhibit 22570-X0897.01, paragraph 19. Exhibit 22570-X0888, paragraph 104.
390 Exhibit 22570-X0551, PDF pages 13-14.
391 Exhibit 22570-X0749, PDF page 30. Exhibit 22570-X0193.01, PDF page 31. Exhibit 22570-X0775, PDF page 15. Exhibit 22570-X0741.01, PDF page 39.
392 Exhibit 22570-X0749, PDF page 31.
393 Exhibit 22570-X0749, PDF page 33.

projections will tend to be too high. If a market has a trend higher in rates, forward curves will tend to be too low.[394]

290. At the same time, Mr. Buttke reiterated his statements from the 2016 GCOC proceeding that "forward rates are a data point – they do not necessarily have to be ignored completely, but their influence as an input should be weighted accordingly."[395] Other utility witnesses came to a similar conclusion that caution needs to be exercised when relying on forward rates in developing the forecasts. Mr. Coyne cautioned "interpreting this data is complicated and would not be a transparent input to the regulatory process."[396] Mr. Hevert pointed out that forward yields have been quite volatile in the period leading up to this proceeding; however, despite the volatility, "they consistently have indicated expectations for interest rate increases."[397] Both Mr. Hevert and Dr. Villadsen indicated that, in any event, implied forward curve rates are well known and considered by professionals making forecasts, such as Consensus Forecasts.[398]

291. As mentioned in Section 6, Mr. Thygesen also drew the Commission's attention to the flattening of the yield curve. Mr. Thygesen referenced several articles indicating that the U.S. yield curve is flattening with the difference between short-term and long-term yields being at its lowest since November 2007.[399] The articles also indicated that if the yield curve becomes inverted (with long-term rates below short-term rates), this "has proven a reliable indicator of impending economic slumps."[400]

292. Mr. Buttke countered that it is not always the case that a flattening yield curve may become inverted thus signalling the advent of lower interest rates, and it is important to know what drives the shape of the yield curve. In this regard, Mr. Buttke pointed to the same Bloomberg article cited by Mr. Thygesen, as well as U.S. Treasury press releases, which led Mr. Buttke to conclude that changes in the mix of Treasury bonds to include a greater proportion of notes in two- to five-year maturities has changed and influenced the shape of the yield curve.[401] Mr. Buttke pointed out that inverted yield curves are typically associated with restrictive monetary policy,[402] and he presented charts showing that "yield curves have gone through many periods where they have flattened only to re-steepen quickly or to remain flat for a number of years and then re-steepen."[403] Based on the above, Mr. Buttke concluded that "There is no reason to assume that current yield curve levels are outside of historical ranges and little reason to predict that a recession is likely to happen in the near term based on the shape of the yield curve."[404]

394 Exhibit 22570-X0749, PDF page 35.
395 Exhibit 22570-X0749, PDF page 39.
396 Exhibit 22570-X0775, PDF page 18.
397 Exhibit 22570-X0741.01, PDF page 37.
398 Exhibit 22570-X0193.01, PDF page 34. Exhibit 22570-X0741.01, PDF page 41.
399 Exhibit 22570-X0551, PDF pages 20-25.
400 Exhibit 22570-X0551, PDF pages 21-24.
401 Exhibit 22570-749, PDF page 51.
402 Exhibit 22570-749, PDF pages 53-54.
403 Exhibit 22570-749, PDF pages 56-60.
404 Exhibit 22570-749, PDF page 60.

## Commission findings

293. In Decision 3539-D01-2015, the Commission considered that "the forward curve acts as an indication of what future interest rates are currently expected to be and can be considered for forecasting purposes."[405] The Commission continues to hold this view, while acknowledging the limitations of relying on the implied forward curve rates, as they are not "necessarily pure measures of market expectations."[406] In general, the Commission agrees with the view that implied forward yields are among the data points that can be used to develop interest rate forecasts.

294. The Commission also continues to see merit in using both the current and expected interest rates in considering a reasonable risk-free rate forecast. This was the Commission's approach in the 2013 and 2016 GCOC decisions and that of Mr. Hevert and Dr. Cleary in this proceeding. As Dr. Cleary explained, utilizing the existing rates as a forecast is an accepted method that "offer[s] the benefit of a starting point that reflects actual yields (i.e., yields that investors can actually achieve today), rather than forecasts which may or may not materialize."[407] This approach has been of assistance to the Commission following the 2008-2009 financial crisis, when interest rates and other financial indicators behaved in a less-than-predictable way.[408]

295. As illustrated in Figure 7, over the course of this proceeding (November 2017 to March 2018), the yield on long-term GOC bonds fluctuated around the 2.3 per cent level, which was also the average yield for that period.[409] The Commission finds this to be a reasonable starting point for the risk-free rate in its current analysis.

296. Regarding the expected rates, the Commission has examined the long-term rate forecasts put forward by parties and observes that there appears to be a broad consensus among various forecasting bodies (shared by most parties in this proceeding) that long-term interest rates are likely to rise throughout the 2018-2020 period. Nevertheless, the pace and magnitude of any increase remain uncertain given the evidence. For example, the RBC Financial Markets Monthly, relied upon by Mr. Hevert and Mr. Johnson, predict long-term government bond yields to reach 3.3 per cent in Canada and 3.85 per cent in the U.S. by the end of 2019. However, the Commission notes that the RBC reports from September 2017 and October 2017 predicted the GOC long-term rates to reach 3.3 per cent by the end of 2018,[410] but starting in January 2018, RBC revised these forecasts downwards with rates predicted to be 3.15 per cent by the end of 2018 and reaching 3.30 per cent in the second half of 2019.[411] The U.S. forecasts were similarly revised.

297. Also potentially tempering forecasted interest rate increases is the flattening yield curve. In Section 6, the Commission took note of the flattening yield curve for Canadian and U.S. government bond yields experienced in the period leading up to, and over the course of this

405 Decision 3539-D01-2015, paragraph 834.
406 Exhibit 22570-X0749, PDF page 31.
407 Exhibit 22570-X0562.01, PDF page 10.
408 For example, the Commission observed in the 2016 GCOC decision that, rather than increasing to just under four per cent, as was generally expected in the 2013 GCOC proceeding, yields on long-term GOC bonds fell by some 100 bps, from approximately 3.0 per cent to approximately 2.0 per cent.
409 Exhibits 22570-X0835 and 22570-X0836.
410 Exhibit 22570-X0159, PDF pages 92 and 101.
411 Exhibit 22570-X0869.

proceeding, as depicted in Figure 1. Taking into account the current and expected flattening of the yield curve, the Commission concludes that over the 2018-2020 test period, the spread between 10-year and 30-year GOC bonds is likely to be lower than the historical average of some 50 bps that the Commission has accepted in past GCOC decisions. All other things being equal, this calls for lower long-term estimates derived from the Consensus Forecasts, which only predicts yields on 10-year GOC bonds. As well, the Commission finds that this flattening of the yield curve may imply that long-term interest rates may not rise in lockstep, or at all, with the increase in the short-term rates.

298. Mr. Buttke expressed his view that the driving forces behind the current flattening of the yield curve give "little reason to predict that a recession is likely to happen in the near term based on the shape of the yield curve"[412] and presented charts showing that "yield curves have gone through many periods where they have flattened only to re-steepen quickly or to remain flat for a number of years and then re-steepen,"[413] and as such, "a flattening curve does not mean that bond yields cannot rise."[414] In contrast, Mr. Thygesen referenced publications claiming that a flattening yield curve argues against higher interest rates and that if the yield curve does become inverted, this historically has been a reliable precursor of recessions with the yield curve inverting just before each of the past seven American recessions.[415] In the Commission's view, it is not possible to discount the likelihood of either outcome at this time (i.e., that the flattening yield curve may steepen or remain flat with long-term rates still increasing, as surmised by Mr. Buttke, or that the flattening of the yield curve will continue until it inverts which, in the past, has been an indicator of a pending recession).

299. In light of the above and considering the findings in Section 6, the Commission cannot reasonably conclude that the long-term interest rates (as measured by the yield on long-term Canada bonds) are likely to increase significantly, if at all, over the 2018-2020 test period. Accordingly, the Commission finds that the prevailing yield on long-term GOC bonds of 2.3 per cent represents a reasonable estimate of the risk-free rate over the 2018-2020 term. In the Commission's view, it is reasonable to expect some continued fluctuation in long-term interest rates, both upward and downward, around the 2.3 per cent estimate over the forecast period.

### 8.2.2 Market equity risk premium

300. Dr. Villadsen provided the following description of the MERP:

> Like the cost of capital itself, the market equity risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can expect to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable, and must be inferred or forecasted based on known market information.
>
> One commonly use [*sic*] method for estimating the MERP is to measure the historical average premium of market returns over the income returns on risk-free government bonds over some long historical period.

[412] Exhibit 22570-X0749, A35.
[413] Exhibit 22570-X0749, A35.
[414] Exhibit 22570-X0749, A35.
[415] Exhibit 22570-X0551, PDF page 21.

> An alternative approach to estimating the MERP eschews historical averages in favor of using current market information and forecasts to infer the expected return on the market as a whole, which can then be compared to prevailing government bond yields to estimate the equity risk premium.[416]

301. Dr. Villadsen used the arithmetic average of annual observed Canadian MERPs from 1935 to the present as her historical MERP, and used the resulting figure of 5.7 per cent as the MERP in all of her CAPM scenario one calculations.[417] Mr. Coyne used an arithmetic average for his historical Canadian MERP. Using data from 1919 to 2016, he reported a result of 5.60 per cent. Using data from 1926 to 2016 for the U.S., Mr. Coyne reported an arithmetic average for U.S. MERP of 6.94 per cent.[418] Dr. Cleary reported historical Canadian MERPs from 1900 to 2015. Using the arithmetic average, the result was 5.2 per cent. Using the geometric average, the result was 3.3 per cent.[419]

302. Dr. Villadsen, Mr. Coyne and Mr. Hevert also derived forward-looking expected MERP values.

303. Dr. Villadsen provided expected market return rates for Canada and the U.S., determined by Bloomberg using a multi-stage dividend discount model. She also provided the expected 10-year risk-free rates that Bloomberg deduced from the expected market return rates to arrive at their forward-looking MERPs. Dr. Villadsen made a further reduction in order to reflect the spread between the 10-year risk-free rates and the 30-year risk-free rates. The results were a forward-looking MERP estimate of 9.49 per cent for Canada, and 6.76 per cent for the U.S.[420]

304. Based on her proposal that investors' level of risk aversion remains elevated, and the forward-looking MERP estimates being higher than the average, Dr. Villadsen used 8.00 per cent as the MERP in her CAPM scenario two calculations. She stated that this figure is between the forward-looking MERP estimates of 6.76 per cent for the U.S. and 9.49 per cent for Canada. Dr. Villadsen justified the use of Canadian and U.S. MERP estimates because of the substantial interaction of the two markets.[421]

305. Mr. Coyne argued that since both the U.S. and Canadian economies have enjoyed a prolonged low interest rate environment, it should be expected that the historical arithmetic average will understate the current market risk premium.[422] Consequently, he incorporated a forward-looking MERP estimate to respond to changes in capital market conditions.

306. Applying a single-stage DCF methodology, Mr. Coyne calculated the expected market return rates for Canada and the U.S. on a market capitalization-weighted basis for the individual companies in each broad market index (the S&P 500 index for the U.S. and the S&P/TSX Composite index for Canada). He then subtracted his recommended risk-free rates from the

416 Exhibit 22570-X0192.01, PDF pages 24-25.
417 Exhibit 22570-X0193.01, A56.
418 Exhibit 22570-X0131, PDF page 55.
419 Exhibit 22570-X0562.01, Figure 10.
420 Exhibit 22570-X0193.01, A29.
421 Exhibit 22570-X0193.01, A56.
422 Exhibit 22570-X0131, PDF page 56.

expected market return rates to arrive at a MERP estimate of 9.38 per cent for Canada, and 8.89 per cent for the U.S.[423] The results are shown in the following table.

**Table 2. Forward-looking expected MERPs as reported by Mr. Coyne[424]**

| | Canada | U.S. |
|---|---|---|
| | % | |
| Expected market return rates | 12.64 | 12.74 |
| Deduct: recommended 30-year risk-free rates | 3.26 | 3.85 |
| Forward-looking expected MERPs | 9.38 | 8.89 |

307. Noting that the Canadian and U.S. markets are highly correlated, Mr. Coyne averaged the historical and forward-looking MERP estimates for Canada and the U.S., to arrive at a MERP value of 7.70 per cent,[425] which he used in his CAPM analysis.[426]

308. Mr. Hevert proposed that it is important to ensure the expected market return rates and the associated MERP are prospective in nature.[427] He derived forward-looking expected MERPs for Canada and the U.S. using two methods. The first method calculated the expected return rates on the Canadian and U.S. markets, based on the constant growth DCF model, using data provided by Bloomberg. He then subtracted the actual 30-year risk-free rates and calculated the results. He also subtracted the projected 30-year risk-free rates and calculated the results.

309. Mr. Hevert's second method included a semi-log form regression-derived estimate, which used monthly historical returns on the Canadian and U.S. stock markets as the dependent variables, relative to monthly historical yields on long-term government bonds as the independent variables. He then applied the obtained regression coefficients to the actual and projected 30-year risk-free rates.[428]

310. The results of Mr. Hevert's two methods are set out in the following table.

423 Exhibit 22570-X0131, PDF page 56.
424 Exhibit 22570-X0132, worksheet JMC-3 Canada MRP. Exhibit 22570-X0132, worksheet JMC-4 U.S. MRP.
425 Historical Canadian of 5.60 per cent. Historical U.S. of 6.94 per cent. Forward-looking Canadian of 9.38 per cent. Forward-looking U.S. of 8.89 per cent. Average of these four is 7.70 per cent.
426 Exhibit 22570-X0131, PDF pages 57-58.
427 Exhibit 22570-X0153.01, PDF page 86.
428 Exhibit 22570-X0153.01, PDF pages 86-87.

**Table 3. Forward-looking expected MERPs as reported by Mr. Hevert[429]**

| | Canada | Canada | U.S. | U.S. |
|---|---|---|---|---|
| | (%) | | | |
| **Method 1** | | | | |
| Expected market return rates | 14.84 | 14.84 | 13.83 | 13.83 |
| Deduct: actual 30-year risk-free rates | 2.37 | | 2.77 | |
| Deduct: projected 30-year risk-free rates | | 3.01 | | 3.30 |
| Forward-looking expected MERPs | 12.47 | 11.83 | 11.06 | 10.53 |
| | | | | |
| **Method 2** | | | | |
| Regression applied to actual 30-year risk-free rates | 6.89 | | 9.74 | |
| Regression applied to projected 30-year risk-free rates | | 5.37 | | 8.77 |

311. By averaging the results of the two methods for the Canadian market, Mr. Hevert derived his recommended forward-looking expected MERP of 9.14 per cent for his Canadian sample. By averaging the results of the two methods for the U.S. market, Mr. Hevert derived his recommended forward-looking expected MERP of 10.02 per cent for his U.S. sample.[430]

312. Dr. Cleary indicated that it is common practice to use a range of 3-7 per cent for the MERP when using the CAPM, with the large majority of MERP estimates falling in the 4-6 per cent range.[431] He provided evidence which he claimed verified that a well-respected finance professional, textbook author, and provider of financial data uses MERPs in the 4-6 per cent range, and varies the choice of MERP to reflect the level of uncertainty in the market.[432]

313. Based on his belief that stock markets reflect fairly normal conditions, but are experiencing below average volatility, Dr. Cleary used a MERP of five per cent. He stated that this is the mid-point of the commonly used 4-6 per cent range, and it is 20 bps below the long-term historical arithmetic average Canadian MERP of 5.2 per cent.[433] Dr. Cleary added his recommended MERP of five per cent to his recommended risk-free rate of 2.6 per cent, and noted that the resulting 7.6 per cent figure is consistent with his point estimate of 7.5 per cent for the expected long-term Canadian stock market return rate.[434]

314. Dr. Cleary stated that the forward-looking expected MERPs reported by Mr. Hevert and Mr. Coyne were derived based on analyst estimates of growth rates that far exceed GDP growth. He suggested that Dr. Villadsen's forward-looking expected MERP suffered from the same shortcoming.[435]

315. Mr. Hevert and Mr. Coyne submitted that Dr. Cleary's partial reliance on historical MERP values during the current period of low interest rates will understate the cost of equity

[429] Exhibit 22570-X0154.01, worksheets Sch 6 MRP TSX, Sch 6 MRP TSX RA, Sch 6 MRP S&P 500, Sch 6 MRP SBBI RA.
[430] Exhibit 22570-X0153.01, PDF page 87.
[431] Exhibit 22570-X0562.01, PDF page 38.
[432] Exhibit 22570-X0562.01, PDF page 41.
[433] Exhibit 22570-X0562.01, PDF page 38.
[434] Exhibit 22570-X0562.01, PDF page 35.
[435] Exhibit 22570-X0562.01, PDF pages 42-43.

because of the inverse relationship between interest rates and the observed MERPs.[436] They explained that if current interest rates are low relative to historical levels, then the current MERPs should be relatively higher than their historic levels.[437]

316. The UCA submitted that other than the regression analysis provided by Mr. Coyne to demonstrate the relationship between interest rates and observed MERPs, no evidence was provided on this assumed relationship.[438] The UCA noted Mr. Coyne's concession during the oral hearing that his regression was not statistically significant, and he did not rely on it.[439] Dr. Cleary did not agree that, in general, the MERP increases as interest rates decrease.[440] The UCA argued that if the relationship does exist, the suggestion of rising interest rates brought forward by the Alberta utilities would lead to a decrease in the MERP.[441]

**Commission findings**

317. The historical Canadian MERP values reported by Dr. Villadsen (5.7 per cent), Mr. Coyne (5.6 per cent) and Dr. Cleary (5.2 per cent) were all developed using arithmetic averages. Despite the different time periods used, the MERP values are within a relatively narrow range. The same cannot be said for the forward-looking expected market return rates that Dr. Villadsen, Mr. Coyne and Mr. Hevert used for Canada, when compared to Dr. Cleary's expected long-term market return rate for Canada.

318. Dr. Villadsen's expected market return rates for Canada range from 12.79 to 12.94 per cent using a forward-looking MERP value for Canada of 9.49 per cent, and her risk-free rate estimates for Canada of 3.30-3.45 per cent. Mr. Coyne's expected market return rate for Canada is 12.64 per cent. Mr. Hevert's expected market return rate for Canada is 14.84 per cent. The resulting range of the utilities experts is 12.64-14.84 per cent, and the average of the four figures is 13.30 per cent.[442] This contrasts significantly with the 7.5 per cent that Dr. Cleary considers to be a reasonable point estimate for the expected market return rate for Canada, as described in Section 8.5.

319. As noted by Dr. Cleary, the expected market return rates used by Mr. Coyne and Mr. Hevert use analyst estimates of growth rates that far exceed expected GDP growth. The Commission has commented in Section 8.4 that market return growth rates that far exceed expected GDP growth are not sustainable, particularly for utilities. The Commission finds that because Mr. Coyne's and Mr. Hevert's proposed market return rates significantly exceed expected GDP growth rate, these estimates are too high. However, no evidence was provided on the record that would enable the Commission to quantify the extent of these overstatements.

320. With respect to Dr. Cleary's point estimate of 7.5 per cent for the expected market return rate for Canada, the Commission has addressed this in Section 8.5.

436 Exhibit 22570-X0741.01, PDF page 42. Exhibit 22570-X0775, PDF page 25.
437 Transcript, Volume 6, page 1198. Exhibit 22570-X0775, PDF page 25.
438 Exhibit 22570-X0913, paragraph 48.
439 Transcript, Volume 5, page 881.
440 Transcript, Volume 9, page 2005.
441 Exhibit 22570-X0913, paragraph 49.
442 Average of 12.79 per cent, 12.94 per cent, 12.64 per cent and 14.84 per cent.

321. The Commission has been presented with a range of 7.5 to 14.84 per cent for the expected market return for Canada. The Commission finds this range too wide to be informative. Directionally, the Commission cannot take any guidance from the changes in the MERP estimates that were provided in the 2016 GCOC proceeding, because some estimates increased, some decreased and others remained unchanged.

322. Consequently, the Commission will place no weight on the expected market return rates for Canada in assessing a reasonable MERP value. As a result, the Commission will consider the historical Canadian MERP rates on the record of the proceeding, and the results produced by Mr. Hevert's regression method, in determining a reasonable MERP.

323. As mentioned above, Dr. Villadsen, Mr. Coyne and Dr. Cleary provided historical MERP rates for Canada that range from 5.2 per cent to 5.7 per cent. The results of Mr. Hevert's regression model are 5.37 per cent using a risk-free rate of 3.01 per cent, and 6.89 per cent using a risk-free rate of 2.37 per cent. In Section 8.2.1 the Commission found that the prevailing yield on long-term GOC bonds over the course of this proceeding of 2.3 per cent represents a reasonable estimate of the risk-free rate over the 2018-2020 term. Using Mr. Hevert's regression analysis as a guide, this suggests a MERP that is in excess of 6.89 per cent. The use of a MERP in excess of 6.89 per cent corresponds to the submissions of Mr. Hevert and Mr. Coyne that, in the current low interest rate environment, the forward-looking MERP should be greater than the historical Canadian average, which has ranged from 5.2 to 5.7 per cent. In the 2016 GCOC decision, the Commission acknowledged the inverse relationship between the risk premium and the level of interest rates.[443] The Commission continues to acknowledge this relationship.

### 8.2.3 Beta

324. The final element of the CAPM is the beta (β) coefficient. Beta is a statistical measure describing the relationship of a given security's return with that of the equity market as a whole. In essence, beta is a measure of market risk of an equity security. Past data (with or without adjustment) is normally used to estimate the expected beta going forward. As expressed in previous GCOC decisions, the Commission considers that the appropriate beta to use is one that reasonably represents the relative risk of stand-alone Canadian utilities.

325. The betas that Mr. Coyne estimated were 0.75 for his Canadian utility proxy group, 0.67 for his U.S. electric proxy group, and 0.68 for his North American electric proxy group,[444] using the estimates from Value Line and Bloomberg, based on weekly stock returns over a five-year period. Both beta estimation techniques are adjusted to compensate for the tendency to revert toward the market mean of 1.0 over time.

326. Dr. Villadsen used adjusted historical betas obtained from Bloomberg, using weekly returns over a three-year period. In applying her beta calculation, Dr. Villadsen developed value-weighted portfolio betas for each of her proxy groups, which she explained is warranted since it may cancel out any idiosyncratic fluctuations of an individual company and provide a better estimate of beta.[445] Dr. Villadsen's proxy groups yielded the following average betas: Canadian utility proxy group: 0.850; U.S. electric utility proxy group: 0.614; U.S. gas LDC utility proxy

[443] Decision 20622-D01-2016, paragraph 228.
[444] Exhibit 22570-X0131, PDF pages 48-53.
[445] Exhibit 22570-X0193.01, PDF pages 61-62.

group: 0.669; and U.S. water utility proxy group: 0.750. The value-weighted portfolio betas for each of her proxy groups were Canadian utility proxy group: 0.950; U.S. electric utility proxy group: 0.578; U.S. gas LDC utility proxy group: 0.659; and U.S. water utility proxy group: 0.644.

327. Mr. Hevert relied on adjusted beta estimates from Value Line and Bloomberg based on five years of weekly return data. Mr. Hevert's resulting average of the adjusted beta estimates was 0.72 for his Canadian utility proxy group, and 0.62 for his U.S. utility proxy group.[446]

328. To develop his beta range, Dr. Cleary analyzed betas using total monthly returns for the TSX Utilities Index for several different periods from 1998 to 2017 and compared this to the average beta of his three proxy groups as of November 2017, based on 60 months of returns. Dr. Cleary determined that combining the analysis resulted in a reasonable range of 0.30 to 0.60. To be consistent with previous proceedings, Dr. Cleary put forth the mid-point of 0.45 as his best point estimate. Dr. Cleary explained that this is slightly above the long-term average Canadian utility beta estimate of 0.35.[447]

329. The utilities pointed out that Dr. Cleary's reported beta coefficients have significantly increased, from an average of 0.21 in the 2016 GCOC proceeding to an average of 0.43 in the current proceeding. The utilities pointed out that Dr. Cleary's directional increase in beta is consistent with Mr. Hevert's findings in this proceeding, and explained that this clearly indicates that the relative risk of Canadian utilities has increased.[448]

330. A point of disagreement in this proceeding was whether adjusted or unadjusted betas, often referred to as "raw betas," should be used in the CAPM. Adjusted betas refer to betas derived from adjustments to the raw betas for the purpose of forward estimation. For example, the "Blume" adjustment (named after Professor Marshall Blume) is a well-known method by which adjusted betas are calculated by giving two-thirds weight to the calculated raw beta and one-third weight to the market average beta of one.[449]

331. Dr. Cleary explained that when developing beta estimates for Canadian utilities, it is inappropriate to use betas that are adjusted toward 1.0, since they have averaged 0.31-0.35 over the last 25-28 years, and have never approached 1.0 in practice.[450] Dr. Cleary noted Mr. Hevert's comment that the purpose of the Blume adjustment is to adjust the beta toward its mean value. As a result, Dr. Cleary submitted that the utilities' beta should be adjusted toward its mean value rather than the market value of 1.0.[451] Dr. Cleary explained that the Blume adjustment is not founded on any conceptual basis, but rather it is purely empirical in nature.

332. Mr. Hevert explained that adjusted betas are commonly used in standard practice and serve as a means to address the Commission's concerns with respect to the wide range of betas provided on the record of the last GCOC proceeding.[452] Mr. Hevert compared adjusted and unadjusted betas for his Canadian utility proxy group and found that the adjusted betas' variation

[446] Exhibit 22570-X0153.01, PDF page 106.
[447] Exhibit 22570-X0562.01, PDF pages 44-48.
[448] Exhibit 22570-X0890.01, PDF pages 21-22.
[449] Exhibit 22570-X0913, PDF page 21
[450] Exhibit 22570-X0565, PDF pages 3-4.
[451] Exhibit 22570-X0897.01, PDF pages 20-21.
[452] Decision 20622-D01-2016, paragraph 317.

for the time period analyzed was much lower. Mr. Hevert explained this suggests that use of adjusted betas addresses the Commission's concerns with respect to the wide range of betas.[453] In response to Dr. Cleary's comment that the adjustment should be toward the utilities' average beta, Mr. Hevert noted that:

> because Blume's research was based on Beta coefficients estimated relative to the market as a whole, his correction, which is approximated by an α of 0.67, cannot be translated to an adjustment to the raw Beta coefficient assuming a non-market mean Beta coefficient, such as Dr. Cleary's 0.35 average[454]

333. Mr. Coyne also considered that Dr. Cleary's recommended beta of 0.45 should be dismissed as an outlier, in part because the Blume adjustment was not applied.[455]

334. Another point of disagreement in this proceeding was whether monthly or weekly betas should be used to develop CAPM estimates.

335. Dr. Villadsen explained that Dr. Cleary presented only monthly betas and relied nearly exclusively on those to inform his recommendation. Dr. Villadsen submitted that Dr. Cleary ignores the fact that using weekly data is statistically superior relative to monthly betas during the time period which he analyzes.[456] Dr. Villadsen explained that monthly betas "have become statistically imprecise and unreliable in the years following the global financial crisis"[457] and weekly betas have become the "standard practice."[458] Dr. Villadsen compared unadjusted weekly and monthly betas and found that the estimation of error was approximately twice as large using monthly data.[459] Dr. Villadsen explained further that Dr. Cleary's long-term beta estimate is biased downward since it considers anomalous periods such as the dot-com bubble period.[460]

336. Mr. Hevert explained that weekly data as opposed to monthly data is more appropriate because monthly data gives less weight to the market movements experienced over shorter time periods and, as a result dampens volatility.[461] Additionally, Mr. Hevert compared monthly and weekly betas of his Canadian utility proxy group and his U.S. utility proxy group, and found that there are a greater number of negative beta coefficients observed when monthly returns are assumed.[462]

337. Mr. Coyne presented several charts in order to compare monthly and weekly betas and commented that the use of weekly returns tends to correlate more closely with the market than do monthly returns. Mr. Coyne conducted a statistical analysis to determine the explanatory power of weekly and monthly beta coefficients. Observing the results of his analysis, Mr. Coyne noted that weekly betas were statistically significant over the two- and five-year periods analyzed,

[453] Exhibit 22570-X0153.01, PDF page 80.
[454] Exhibit 22570-X0890.01, PDF page 52.
[455] Transcript, Volume 5, page 954.
[456] Exhibit 22570-X0767.01, PDF pages 39-40.
[457] Exhibit 22570-X0767.01, PDF page 47.
[458] Transcript, Volume 2, page 288.
[459] Exhibit 22570-X0767.01, PDF pages 128-129.
[460] Exhibit 22570-X0767.01, PDF page 135.
[461] Exhibit 22570-X0153.01, PDF page 81.
[462] Exhibit 22570-X0153.01, PDF page 83.

whereas the monthly betas were not.[463] In his evidence, Mr. Coyne recognized that both monthly and weekly returns are commonly accepted in practice; however, due to the results of his analysis, Mr. Coyne recommended weekly five-year or two-year betas.[464]

338. Dr. Cleary submitted that both monthly and weekly return data are widely used to determine beta coefficients. Dr. Cleary further explained that he could not offer a definitive opinion on whether monthly or weekly data is best to calculate betas and he did not think that the Commission could conclusively decide the issue.[465] The UCA submitted that the pragmatic approach is to consider both monthly and weekly return data, which is the approach adopted by Dr. Cleary.[466]

339. The UCA disagreed with Dr. Villadsen's view that weekly betas have become standard practice. The UCA further explained that her comments are not reflective of a recent text which she co-authored, "Risk and Return for Regulated Industries," in which the use of monthly return is cited as the common approach.[467]

**Commission findings**

340. In the 2016 GCOC proceeding, witnesses recommended beta estimates in the range of 0.45 to 0.92. In its decision, the Commission observed that all witnesses had employed methods to estimate beta that were generally accepted, but that the resulting beta range of 470 bps was substantially wider than the beta range of 250 bps in the 2013 GCOC proceeding. The Commission found that it could not identify, with any reasonable degree of confidence, a method that allowed the Commission to narrow the range of betas recommended by the witnesses.[468]

341. In its April 20, 2017 letter[469] initiating this proceeding, the Commission stated the following:

> (i) If there is a wide range of beta values provided by the experts, will the Commission be able to identify, with any reasonable degree of confidence, a method that allows the Commission to narrow the range of these betas?

342. In addition to updating their proxy groups, witnesses in this proceeding also presented evidence with respect to the use of weekly versus monthly betas, and the use of the Blume adjustment, to address the above referenced issue.

343. With respect to the use of weekly versus monthly betas, the Commission notes a strong preference for weekly betas by the utility witnesses, whereas Dr. Cleary maintained that there is no clearly superior method. It is clear from the evidence on the record, just as it was in the 2016 GCOC proceeding, that weekly betas are associated with values toward the higher end of the recommended beta range, whereas monthly betas are associated with values toward the lower end of the recommended beta range.

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463 Exhibit 22570-X0131, PDF page 51.
464 Exhibit 22570-X0131, PDF page 53.
465 Transcript, Volume 10, pages 2123-2124.
466 Exhibit 22570-X0913, PDF page 24.
467 Exhibit 22570-X0897.01, PDF page 25.
468 Decision 20622-D01-2016, PDF page 46.
469 Exhibit 22570-X0078, PDF page 1.

344. The Commission is not persuaded that weekly betas are clearly superior in all instances to monthly betas as there remains some uncertainty and disagreement in the evidence on this point. Indeed, practitioners continue to use both weekly and monthly data, and the investment research firms that provide the data upon which analysts rely continue to provide both weekly and monthly data, including betas derived from both weekly and monthly data. Accordingly, the Commission will continue to consider both weekly and monthly based beta estimates in determining reasonable beta estimates.

345. There was also considerable debate in this proceeding over the use of the Blume adjustment. In the 2013 GCOC decision, the Commission acknowledged that adjusted betas are widely disseminated to investors by investment research firms, including Bloomberg, Value Line and Merrill Lynch. However, the Commission also indicated continued uncertainty about whether an adjustment is warranted for the betas of regulated utilities.[470]

346. The Commission has not been persuaded in this proceeding that adjusted betas are superior to unadjusted betas in the context of regulated utilities. The Commission continues to hold the view expressed in the 2016 GCOC proceeding that both raw betas and adjusted betas provide useful information with respect to utility risk.[471]

347. The low end of Dr. Cleary's recommended beta range, 0.30, was developed based on the long-term average over the last 25-28 years. The Commission agrees with Dr. Villadsen's submission that this estimate is biased downward since it considers anomalous periods such as the aftermath of the dot-com bubble.[472] Even Dr. Cleary acknowledged during the 2016 GCOC proceeding that betas from 1998 to 2002 were not meaningful.[473]

348. Dr. Villadsen stated that each beta calculated for up to five years after the dot-com bubble era is still contaminated by the anomalous data. She added that in order to eliminate the trailing impact of this anomalous data, a credible long-term average would have to exclude betas measured using data from 1998 to 2007.[474] The Commission agrees. The Commission derived the resulting long-term average beta for the TSX Utility sub-index, excluding data from 1998 to 2007. The resulting average was 0.47.[475] Based on this, the Commission finds that the low-end beta of 0.30 proposed by Dr. Cleary can be excluded.

349. The Commission considers Dr. Cleary's recommended beta of 0.45 to be the lower bound for a reasonable range of betas values. The 0.45 value does not significantly differ from the Commission's recalculated long-term average beta of 0.47, nor the 0.43 average Dr. Cleary calculated for his nine company Canadian utility proxy group.[476] The Commission also considers that the value-weighted portfolio beta value associated with Dr. Villadsen's Canadian utility

470 Decision 20622-D01-2016, pdf 46.
471 Decision 20622-D01-2016, pdf 46.
472 Exhibit 22570-X0767.01, PDF page 135.
473 Exhibit 22570-X0786.01, A10.
474 Exhibit 22570-X0786.01, A10.
475 Using data from Exhibit 20622-X0464, worksheet Rolling Results. Dr. Cleary, in Exhibit 22570-X0565, PDF page 2, references Figure 6 from Exhibit 20622-X0457. Exhibit 20622-X0457 was Dr. Villadsen's rebuttal evidence from the 2016 GCOC proceeding. The working paper underlying Figure 6 of her rebuttal evidence is in Exhibit 20622-X0464.
476 Exhibit 22570-X0562.01, Table 8.

proxy group, 0.95, represents an upper bound for a reasonable range of betas. Accordingly, the Commission considers that a reasonable range of betas is 0.45 to 0.95.

### 8.2.4 The resulting CAPM estimate

350. The witnesses in this proceeding presented a large number of CAPM estimates by varying input parameters for each of the risk-free rate, beta and MERP.

351. Table 4 below summarizes the CAPM estimates and input parameters.

**Table 4. CAPM inputs and resulting ROE estimates**

| | Rf | Beta | MERP | Float | Adj | ROE |
|---|---|---|---|---|---|---|
| | (%) | | (%) | | | (%) |
| Cleary-recommendation | 2.60 | 0.450 | 5.00 | 0.50 | 0.13% | 5.48 |
| Coyne-Canadian utility proxy group | 3.26 | 0.749 | 7.70 | 0.50 | N/A | 9.53 |
| Coyne-U.S. electric proxy group | 3.85 | 0.666 | 7.70 | 0.50 | N/A | 9.49 |
| Coyne-North American electric proxy group | 3.73 | 0.682 | 7.70 | 0.50 | N/A | 9.48 |
| Hevert-Canadian utility proxy group | 3.08 | 0.717 | 9.14 | 0.50 | N/A | 10.13 |
| Hevert-U.S. utility proxy group-2018 | 3.30 | 0.624 | 10.02 | 0.50 | N/A | 10.08 |
| Hevert-U.S. utility proxy group-2019 | 4.20 | 0.624 | 10.02 | 0.50 | N/A | 10.96 |
| Hevert-U.S. utility proxy group-2020 | 4.30 | 0.624 | 10.02 | 0.50 | N/A | 11.06 |
| Villadsen-Scenario 1-Cdn. utility proxy group-low | 3.45 | 0.850 | 5.70 | 0.50 | N/A | 8.80 |
| Villadsen-Scenario 1-Cdn. utility proxy group-high | 3.45 | 0.950 | 5.70 | 0.50 | N/A | 9.40 |
| Villadsen-Scenario 1-U.S. gas LDC utility proxy group-low | 3.45 | 0.663 | 5.70 | 0.50 | N/A | 7.70 |
| Villadsen-Scenario 1-U.S. gas LDC utility proxy group-high | 3.45 | 0.669 | 5.70 | 0.50 | N/A | 7.80 |
| Villadsen-Scenario 1-U.S. electric utility proxy group-low | 3.45 | 0.578 | 5.70 | 0.50 | N/A | 7.20 |
| Villadsen-Scenario 1-U.S. electric utility proxy group-high | 3.45 | 0.608 | 5.70 | 0.50 | N/A | 7.40 |
| Villadsen-Scenario 1-U.S. water utility proxy group-low | 3.45 | 0.644 | 5.70 | 0.50 | N/A | 7.60 |
| Villadsen-Scenario 1-U.S. water utility proxy group-high | 3.45 | 0.750 | 5.70 | 0.50 | N/A | 8.20 |
| Villadsen-Scenario 2-Cdn. utility proxy group-low | 3.30 | 0.850 | 8.00 | 0.50 | N/A | 10.60 |
| Villadsen-Scenario 2-Cdn. utility proxy group-high | 3.30 | 0.950 | 8.00 | 0.50 | N/A | 11.40 |
| Villadsen-Scenario 2-U.S. gas LDC utility proxy group-low | 3.30 | 0.663 | 8.00 | 0.50 | N/A | 9.10 |
| Villadsen-Scenario 2-U.S. gas LDC utility proxy group-high | 3.30 | 0.669 | 8.00 | 0.50 | N/A | 9.20 |
| Villadsen-Scenario 2-U.S. electric utility proxy group-low | 3.30 | 0.578 | 8.00 | 0.50 | N/A | 8.40 |
| Villadsen-Scenario 2-U.S. electric utility proxy group-high | 3.30 | 0.608 | 8.00 | 0.50 | N/A | 8.70 |
| Villadsen-Scenario 2-U.S. water utility proxy group-low | 3.30 | 0.644 | 8.00 | 0.50 | N/A | 9.00 |
| Villadsen-Scenario 2-U.S. water utility proxy group-high | 3.30 | 0.750 | 8.00 | 0.50 | N/A | 9.80 |

**Commission findings**

352. The results in Table 4 above, show a wide range of ROE estimates based on CAPM, ranging from 5.48 per cent (Dr. Cleary's recommended value) to 11.40 per cent (Villadsen-Scenario 2-Canadian utility proxy group, which uses the value-weighted portfolio beta of 0.950).

353. The wide range of CAPM estimates is not surprising, given the Commission's determination above that the use of weekly and monthly based beta estimates, as well as the use of adjusted and unadjusted betas in the CAPM model, are acceptable. This wide range of CAPM results does not, on its own, provide much assistance to the Commission in determining an approved ROE. Nonetheless, the Commission has determined, as discussed below, a point estimate of 7.90 per cent with respect to the CAPM, which it will consider in establishing the ROE fair return for the affected utilities.

354. Given the uncertainty regarding the magnitude and timing of potential changes in the risk-free rate, as discussed in Section 8.2.1, the Commission considers the estimate of 2.60 per cent recommended by Dr. Cleary to be reasonable. With respect to beta, as explained in Section 8.2.3, the Commission found that the low-end beta of 0.30 proposed by Dr. Cleary can be excluded. Further, as explained in Section 8.1, the Commission will disregard any beta coefficients derived in connection with Dr. Villadsen's U.S. pipeline proxy group and its subsample group. From the remaining betas, the Commission has determined an average beta of 0.686.[477] In Section 8.2.2, the Commission's findings suggested a MERP that is in excess of 6.89 per cent. The Commission considers a MERP of 7.00 per cent to be reasonable for determining a point estimate. Using the risk-free rate of 2.60 per cent, along with a MERP of 7.00 per cent, an average beta of 0.686 and allowing for a flotation allowance of 0.50 per cent results in an ROE estimate of 7.90 per cent.

355. In the 2016 GCOC decision, the Commission noted that Dr. Booth placed less weight on his CAPM models due to abnormally low interest rates.[478] The Commission also noted Dr. Villadsen's testimony in the 2016 GCOC proceeding that she had placed less weight on her CAPM models than in the past.[479] In the current proceeding, Mr. Hevert indicated that he had placed less weight on his CAPM model as well.[480] The Commission considers that while interest rates have risen somewhat since the time of the 2016 GCOC proceeding, they are still low relative to average historical rates and accordingly, the Commission will give less weight to the CAPM ROE results put forward in this proceeding.

356. The Commission also gave less weight to parties' CAPM estimates in the 2016 GCOC decision, compared to the CAPM estimates in the 2013 GCOC proceeding, largely due to the Commission's finding that it could not identify, with any reasonable degree of confidence, a method that allowed the Commission to narrow the range of betas recommended by the experts in that proceeding.[481] Also, given that the range of betas has increased slightly in this proceeding (even after the Commission rejected certain results on the extreme ends of the original range presented, as discussed above), the relatively wide range of betas, compared to the 2013 GCOC proceeding, continues to be a factor that leads the Commission to assign less weight to the CAPM ROE results.

### 8.2.5 The ECAPM

357. Consistent with their evidence filed in the 2016 GCOC proceeding, Dr. Villadsen and Mr. Hevert noted that empirical research has shown that the actual security market line (SML) described by the CAPM formula is not as steeply sloped as the predicted SML. In other words, low-beta securities earn returns somewhat higher than CAPM would predict, and high-beta

[477] This is the average of the following betas: 0.450 recommended by Dr. Cleary; 0.749 from Mr. Coyne's Canadian utility proxy group; 0.666 from Mr. Coyne's U.S. electric proxy group; 0.717 from Mr. Hevert's Canadian utility proxy group; 0.624 from Mr. Hevert's U.S. utility proxy group; 0.850 from Dr. Villadsen's Canadian utility proxy group; 0.950 from Dr. Villadsen's portfolio beta for her Canadian utility proxy group; 0.669 from Dr. Villadsen's U.S. gas LDC utility proxy group; 0.663 from Dr. Villadsen's portfolio beta for her U.S. gas LDC utility proxy group; 0.614 from Dr. Villadsen's U.S. electric utility proxy group; 0.578 from Dr. Villadsen's portfolio beta for her U.S. electric utility proxy group; 0.750 from Dr. Villadsen's U.S. water utility proxy group; 0.644 from Dr. Villadsen's portfolio beta for her U.S. water utility proxy group.

[478] Decision 20622-D01-2016, paragraph 311.

[479] Decision 20622-D01-2016, paragraph 309.

[480] Exhibit 22570-X0153.01, PDF page 95.

[481] Decision 20622-D01-2016, paragraph 317.

securities earn returns somewhat lower than predicted.[482] The ECAPM adds an empirical adjustment factor to CAPM (referenced as "X" by Mr. Hevert and as "alpha" by Dr. Villadsen) intended to adjust the SML to account for the difference between the predicted returns for a given beta when using CAPM and future, realized returns for the same or similar beta.[483]

358. As in the 2016 GCOC proceeding, both Mr. Hevert and Dr. Villadsen relied on the use of the ECAPM in developing their ROE estimates, although their models were of a different form and used different notation. These witnesses confirmed there was no conflict between their two approaches.[484]

359. In applying his version of the ECAPM, Mr. Hevert used an empirical factor of 0.25, based on the published work of Dr. Morin. Mr. Hevert's ECAPM results averaged 9.57 per cent in 2017 and 10.27 per cent in 2018 for Canada, and were in the 10.00 to 11.50 per cent range for the U.S. over the 2017-2020 period. These results were approximately 60 bps higher than his estimates using CAPM for his Canadian utility proxy group and 100 bps higher than for his U.S utility proxy group.

360. Dr. Villadsen used an alpha factor of 1.5 per cent, based on an average adjustment factor from academic literature, which she further adjusted downward to account for differences in government bond maturities and to be conservative. Dr. Villadsen's ECAPM results were 10 to 20 bps higher than the CAPM results for her Canadian utility proxy group and were approximately 40 to 70 bps higher than the CAPM results for her three main U.S proxy groups.[485]

361. Dr. Cleary stated that "Using the [ECAPM] also implicitly adjusts the beta used in traditional CAPM estimates. Hence, the ECAPM should also not be used."[486] Mr. Hevert and Dr. Villadsen disagreed with this conclusion.

362. In argument, Calgary pointed out that in the 2004 GCOC decision, the Commission's predecessor stated:

> The Board notes Calgary/CAPP's [Canadian Association of Petroleum Producers] argument that applying CAPM using long-term interest rates (long-Canada bond yields) in determining the risk-free rate, as was done by all experts in this Proceeding, already corrects for the alleged under-estimation that ECAPM was designed to address. Calgary/CAPP argued that the under estimation would only be present if the CAPM were applied using short-term interest rates, which none of the experts did in this Proceeding.
>
> The Board finds the Calgary/CAPP position persuasive and considers that the use of long-term Canada bond yields largely adjusts for the tendency of CAPM, when based on short-term interest rates, to under estimate the required returns for lower risk companies. Therefore, the Board will only place limited weight on the results of the ECAPM model.[487]

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[482] Exhibit 22570-X0153.01, PDF page 84.
[483] Exhibit 22570-X0153.01, PDF pages 84-85. Exhibit 22570-X0193.01, PDF page 62.
[484] Transcript, Volume 4, page 680. Transcript, Volume 6, page.
[485] U.S. electric utility proxy group, U.S. gas local LDC utility proxy group, U.S. water utility proxy group.
[486] Exhibit 22570-X0562.01, PDF page 50.
[487] Decision 2004-052: Generic Cost of Capital, Application 1271597-1, July 2, 2004, page 22.

363. Calgary further submitted that "ECAPM is not academically respected, is not in textbooks and has not been a topic in finance research … which has long since moved into looking at multi-factor models."[488] If any improvement over the CAPM were required, Calgary appeared to express its preference for using multi-factor models such as the Fama-French model.[489]

364. The UCA raised similar points and endorsed Dr. Cleary's view that the ECAPM "is not very widely used in practice."[490] The UCA also pointed to the "dated nature of the literature" or research underlying the adjustment factors used by Dr. Villadsen and Mr. Hevert. For these reasons, the UCA recommended the Commission not place any weight on the results obtained using the ECAPM.[491]

**Commission findings**

365. In the 2016 GCOC decision, the Commission stated:

> 199. In the Commission's view, the ECAPM appears to be a model that could contribute to the Commission's determination of a fair allowed ROE. Generally speaking, the Commission is supportive of models and methods that attempt to improve upon CAPM results. The Commission agrees with Mr. Hevert that the selection of an empirical adjustment factor is a matter of judgement. Based on the evidence in this proceeding, however, the Commission has been unable to assess adequately the empirical adjustment factors employed by the experts in exercising their judgement. Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding. In order for the Commission to adequately assess the judgement exercised by the experts, the Commission would require a full explanation justifying the sample and time periods adopted.

366. The Commission benefitted from the evidence provided by parties on ECAPM in this proceeding, including the information provided by Mr. Hevert[492] and Dr. Villadsen[493] on the sample and time periods utilized by the studies supporting the ECAPM. In an exchange with Commission counsel, Dr. Villadsen confirmed that the alpha factors that she relied on are all based on studies prior to 1991, because academic studies have not studied the alpha parameter since then.[494] In an exchange with Calgary counsel, Dr. Villadsen stated:

> Q. And has ECAPM ever been criticized in journals, financial journals, to your knowledge?
> A. DR. VILLADSEN: I don't think the ECAPM has been the topic of discussion in journals that I have reviewed recently.
> Q. Okay.
> A. DR. VILLADSEN: Most have switched to doing multifactor models.[495]

488 Exhibit 22570-X0903, paragraph 54.
489 Exhibit 22570-X0903, paragraphs 52 and 55.
490 Transcript, Volume 10, page 2143.
491 Exhibit 22570-X0897.01, paragraphs 48, 150 and 153.
492 Exhibit 22570-X0159, PDF pages 19-21.
493 Exhibit 22570-X0192.01, PDF pages 28 to 30. Exhibit 22570-X0308, AUI/ATCO-AUC-2017NOV17-011(b), attachment is in Exhibit 22570-X0309.
494 Transcript, Volume 4, page 680.
495 Transcript, Volume 2, page 263.

367. Recognizing that Dr. Morin's data was from the period 1926 to 1984, Mr. Hevert performed his own analysis using data over the 10-year period ending in 2016 to confirm that the premise behind ECAPM is still valid. However, while he was able to confirm the general premise of the ECAPM model, Mr. Hevert acknowledged that his analysis was not designed to confirm the reasonableness of Dr. Morin's alpha coefficients, which he adopted.[496]

368. The Commission also finds informative Mr. Hevert's and Dr. Villadsen's explanations that multi-factor models aim to address the same issue as the ECAPM – specifically, to correct for the fact that the SML is flatter than CAPM predicts, or more generally, to capture asset pricing more accurately than CAPM.[497] While ECAPM performs this correction by way of an empirical adjustment parameter (alpha), the multi-factor models do so by employing several parameters in addition to beta.[498]

369. Based on the evidence in this proceeding, it appears to the Commission that ECAPM attempts to provide a practical solution by introducing an empirical adjustment factor to the CAPM results; increasing the CAPM return estimates for companies with betas lower than one and decreasing the return estimates for companies with betas higher than one. As stated by Dr. Villadsen, "you can think of it as the ECAPM is a shortcut to multifactor models."[499] However, as the Commission pointed out in the 2016 GCOC decision, these adjustment factors are a function of the sample and time period over which the returns were examined, as well as the assumptions employed.[500]

370. Dr. Cleary questioned whether using ECAPM and adjusted betas at the same time "essentially adjusts raw betas twice."[501] Mr. Hevert and Dr. Villadsen maintained that the use of the ECAPM and adjusted betas are meant to address two different issues. They indicated that the studies underlying the theoretical use of the ECAPM did not use adjusted betas to arrive at the empirical adjustment factors.[502] Consequently, different empirical adjustment factors of ECAPM may need to be employed when applied to adjusted betas or, conversely, unadjusted betas may need to be employed in any future ECAPM that relies on the empirical adjustment factors used by Dr. Villadsen and Mr. Hevert.

371. The Commission further observes that all the studies on which Dr. Villadsen relied to determine her empirical adjustment factors relied on monthly stock returns for all stocks traded on the major U.S. stock exchanges. Given that, in this proceeding, Mr. Hevert and Dr. Villadsen employed weekly betas, this may result in a further mismatch. It is also possible that some other modifications to the empirical ECAPM adjustment coefficients may be required, unique to regulated utilities, as the original ECAPM studies from which Mr. Hevert and Dr. Villadsen obtained their adjustment factors, focused on a wide range of companies traded on the equity market.

496 Transcript, Volume 6, pages 1217-1219.
497 Transcript, Volume 4, page 683. Transcript, Volume 6, page 1221.
498 Exhibit 22570-X0918, paragraph 153.
499 Transcript, Volume 4, page 684.
500 Decision 20622-D01-2016, paragraph 197.
501 Exhibit 22570-X0562.01, PDF page 50.
502 Transcript, Volume 4, page 682. Transcript, Volume 6, page 1221.

372. The Commission also remains of the view, expressed in paragraph 200 of the 2016 GCOC decision,[503] that the empirical adjustment factor in ECAPM does not resolve the issue regarding the wide range of estimated betas.

373. For the above reasons, the Commission will not assign significant weight to the ECAPM results in this proceeding. The Commission acknowledges the practical difficulties associated with using the multi-factor models described by Dr. Villadsen at the hearing, such as the need for more data and the need to estimate not just one, but three to four parameters.[504] Nevertheless, the Commission considers it preferable to improve the CAPM results by way of multi-factor models that specifically aim to identify factors explaining the required return, if possible, rather than using empirical adjustment factors as is done under the ECAPM.

### 8.3 Other risk premium models

374. In addition to CAPM and ECAPM, parties relied on other risk premium models. Mr. Hevert and Dr. Cleary explained that risk premium models are based on the basic financial principle that since stocks are riskier than bonds, investors will require a higher return to invest in a firm’s stock than in its bonds.

375. As in previous GCOC proceedings, Dr. Cleary employed a BYPRPM in developing his ROE recommendation. Dr. Cleary explained that under his method, a risk premium in the two to five per cent range is added to the yield on a firm’s outstanding publicly traded, long-term bonds to arrive at a company’s cost of equity estimate, with 3.5 per cent generally added to reflect average risk companies, and lower values added for less risky companies. Given the low-risk nature of Canadian regulated utilities, Dr. Cleary opined that an appropriate risk premium for these companies would be in the two- to three-per-cent range, with a best estimate of 2.5 per cent.

376. Dr. Cleary noted that as of November 15, 2017, the yield on long-term A-rated Canadian utility bonds was 3.51 per cent according to the Bloomberg data. Because this number was close to the yields on outstanding Canadian utility bonds, Dr. Cleary concluded that the 3.5 per cent bond yield was a reasonable starting point for his BYPRPM estimate. After adding his risk premium estimate of 2.5 per cent, Dr. Cleary obtained an ROE estimate of 6.50 per cent, inclusive of the 50 bps flotation allowance.[505]

377. Mr. Hevert employed the two risk premium models that he used in the 2016 GCOC proceeding; the Predictive Risk Premium Model (PRPM) applied to his Canadian and U.S. proxy groups, and the BYPRPM, based on approved returns for U.S. electric utility companies.

378. The PRPM, also referred to in the literature as the “general consumption-based asset pricing model,”[506] estimates the equity risk premium through the prediction of volatility. Specifically, the risk premium derived from the PRPM is based on the premise that the volatility of stock returns and risk premiums changes over time and is related from one period to the next. As such, it can be estimated by using time series analysis tools such as the autoregressive conditional heteroscedasticity (ARCH) model, and its generalized form, the GARCH model. The

[503] Decision 20622-D01-2016.
[504] Transcript, Volume 4, pages 683-684.
[505] Exhibit 22570-X0562.01, PDF pages 66-67.
[506] Transcript, Volume 6, page 1239.

inputs to the PRPM-derived model are the historical returns on the common shares of each proxy company, less the historical monthly yield on long-term government bonds. Using statistical software, Mr. Hevert calculated each proxy company's projected risk premium, which he then added to his recommended average risk-free rates.

379. Mr. Hevert also employed a variant of the BYPRPM that adds a risk premium, calculated as the difference between approved ROEs granted by U.S. regulators and the then-prevailing level of the long-term Treasury yield, to a long-term government bond yield.

380. Mr. Hevert modelled the relationship between interest rates and the risk premium using regression analysis, in which the observed risk premium was the dependent variable, and the average 30-year Treasury yield was the independent variable. According to Mr. Hevert, his regression analysis demonstrated that over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the risk premium.

381. Mr. Hevert noted that in previous GCOC and related decisions, the Commission expressed concerns with relying on returns approved by other regulators in determining the fair ROE for Alberta utilities. Mr. Hevert acknowledged that his approach to BYPRPM is based on the premise that U.S. approved returns are a proxy for required market returns. However, based on his practical experience, Mr. Hevert believed that approved returns are a reasonable input because "investors consider a broad range of data, including returns authorized in other jurisdictions, in establishing their return requirements." In addition, Mr. Hevert stated:

> … Because authorized ROEs reflect both prevailing market conditions during each rate case and the types of market-based models proposed in GCOC proceedings in Alberta, it is reasonable to use authorized returns to estimate the relationship between interest rates and the Equity Risk Premium. As Dr. Morin notes:
>
> > (a)llowed risk premiums are presumably based on the results of market-based methodologies presented to regulators in rate hearings and on the actions of objectives unbiased investors in a competitive marketplace.[136]
>
> ---
>
> [136] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 125.[507]

382. Mr. Coyne introduced a similar model in his rebuttal evidence, where he looked at the relationship between risk-free rates, approved ROEs and the implied risk premium, based on historical allowed returns from 735 U.S. electric utility company rate cases for the period 1992 through 2017. Mr. Coyne performed a regression analysis using the implied risk premium (calculated as a difference between approved ROEs and the then-prevailing 30-year Treasury yields) as a dependent variable and yields on 30-year Treasury bonds as an independent variable.

383. According to Mr. Coyne, the regression results confirmed that the risk premium varies with the level of bond yield, and generally increases as the bond yields decrease, and vice versa; specifically, a one percentage point increase in bond yield results in a 0.55 percentage point decrease to the implied risk premium and thus leads to a 0.45 percentage point increase in the approved ROE. Mr. Coyne claimed that the advantage of this approach is that it allows for examination of the actual risk premium awarded to a large group of utilities over past years,

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[507] Exhibit 22570-X0153.01, PDF page 71.

covering several economic cycles, and the ability to measure the inverse relationship between risk-free rates and the risk premium recognized by regulators.[508]

384. Based on these regression coefficients, Mr. Coyne then estimated the required ROE using current and expected 30-year Treasury bond yields, including the current 30-day average, a near-term Blue Chip consensus forecast for 2018, and a Blue Chip consensus forecast for 2018-2020.

385. The experts critiqued each other's risk premium models. Dr. Villadsen, Mr. Coyne and Mr. Hevert pointed out that Dr. Cleary used the bond yield as of November 2017 in his analysis, rather than a forward-looking estimate applicable to the 2018-2020 test period for this proceeding, and thus did not take into account the expected increase in interest rates. As well, they pointed out that Dr. Cleary's BYPRPM approach relies on a subjective 2.5 per cent risk premium adder that does not take into account the inverse relationship between bond yields and risk premium.[509]

386. Dr. Cleary, in turn, expressed his view that Mr. Hevert and Mr. Coyne have applied the BYPRPM incorrectly:

> This is incorrect, since the BYPRP model, according to the CFA [chartered financial analyst] literature (and numerous other textbooks), and which is commonly used in analyst reports, adds a risk premium to the present yield on a firm's outstanding publicly-traded long-term bonds. It therefore estimates a market-based return based on the yield on a company's outstanding bonds, which is reflective of market yield spreads. It does not use government yields, nor does it use ROEs and it certainly does not use allowed ROEs. Furthermore, the Commission has not applied allowed ROEs in other jurisdictions in previous decisions, including the 2013 GCOC Decision and the 2016 GCOC Decision. [footnote omitted][510]

387. To address Dr. Cleary's point, Mr. Hevert undertook an additional analysis calculating the equity risk premium as the difference between the approved ROEs and the prevailing yield on the Moody's A Utility Bond Index. Mr. Hevert indicated that the results were consistent with his original analysis, and the choice of bond yields (government vs. utility) did not alter the underlying inverse relationship between bond yield and risk premium. Assuming Dr. Cleary's A-rated public utility bond yield of 3.50 percent, Mr. Hevert's revised method produced an ROE of 9.69 per cent, which was within his recommended range.[511]

### Commission findings

388. In previous GCOC decisions, the Commission accepted the BYPRPM approach as a valid tool in estimating the cost of equity as it is simple to use and conforms to the basic principle that investors require a higher return for assets with greater risk. The evidence in this proceeding lends further support to this conclusion.

389. The Commission agrees with the view expressed by both Mr. Hevert and Dr. Cleary that an advantage of this method is that it incorporates readily observable, market-determined data

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508 Exhibit 22570-X0775, PDF pages 20-22 with calculations provided in Exhibit 22570-X0778.

509 Exhibit 22570-X0767.01, PDF page 71. Exhibit 22570-X0775, PDF page 26. Exhibit 22570-X0741.01, PDF page 53.

510 Exhibit 22570-X0562.01, PDF page 67.

511 Exhibit 22570-X0741.01, PDF page 54.

such as bond returns and yields, which in turn can be deconstructed into the risk-free rate and credit spread components.[512] The Commission observes that the credit spread component needed by utility bond investors is imbedded in the return to equity investors, along with some additional margin. However, the remaining margin, the equity risk premium, requires estimation, and thus requires judgment.

390. The BYPRPMs presented by Mr. Hevert, Dr. Cleary and Mr. Coyne start with observable market-based information, specifically the yield on either utility or government long-term bonds. Where utility bonds are used (as was done by Dr. Cleary, and Mr. Hevert in his rebuttal evidence) the bond yield also incorporates a credit spread, which the Commission in past GCOC decisions has accepted to be an objective measure that helps inform the Commission about investors' risk perceptions. However, in the Commission's view, the BYPRPMs presented in this proceeding falter in their application of the equity risk premium adder to the bond yield.

391. In this proceeding, Dr. Cleary recommended using the same 2.5 per cent risk premium value that he recommended in the 2013 and 2016 GCOC proceedings.[513] In the 2013 and 2016 GCOC decisions, the Commission noted the ad hoc nature of Dr. Cleary's BYPRPM approach to the estimation of ROE.[514] As well, the Commission expressed concern with the fact that this approach does not appear to take into account the inverse relationship between the risk premium and interest rates, and therefore, may not apply in an environment of low interest rates.[515] These concerns were shared by the utility experts in this proceeding and in the Commission's view, continue to apply.

392. The BYPRPMs of Mr. Hevert and Mr. Coyne estimate the risk premium component by comparing the approved ROEs to the long-term government bond yields in place at the time, thus capturing the inverse relationship. However, the Commission has two concerns with Mr. Hevert's and Mr. Coyne's approach. First, because their models estimate the risk premium in excess of long-term government bond yields, i.e., the risk-free rate, they lose the advantage of incorporating the observable market data on utilities' credit spreads, as compared to Dr. Cleary's approach.

393. Second, these models use the approved ROEs of other regulators in the U.S. as proxies for the market return. In the Commission's view, although observable, the ROEs approved for the U.S. utilities are not strictly market data. Accordingly, the main assumption of these models, that the approved ROEs represent market return, does not hold, because the approved ROEs would be heavily influenced by the ROEs awarded by other regulators.

394. While Mr. Hevert expressed his belief that "authorized ROEs reflect both prevailing market conditions during each rate case and the types of market-based models proposed in GCOC proceedings in Alberta,"[516] the Commission observed in the 2016 GCOC decision that this may not always be the case. Approved ROEs may be established on a different basis. For example, they may be a result of an ROE adjustment formula or a negotiated settlement, or they may include non-market elements such as incentive mechanisms. This led the Commission to

512 Exhibit 22570-X0153.01, PDF page 68. Transcript, Volume 10, page 2184.
513 Decision 20622-D01-2016, paragraph 226.
514 Decision 2191-D01-2015, paragraphs 260-262. Decision 20622-D01-2016, paragraph 229.
515 Decision 20622-D01-2016, paragraphs 228-229.
516 Exhibit 22570-X0153.01, PDF page 71.

conclude that it "is hard to ascertain whether further adjustments to account for aberrations of this kind are required, without scrutinizing each regulatory decision in detail."[517]

395. For all of the above reasons, the Commission did not place any weight on the results of the BYPRPMs presented by Dr. Cleary, Mr. Hevert or Mr. Coyne.

396. Nevertheless, the Commission finds part of Dr. Cleary's BYPRPM analysis useful. Specifically, the Commission takes note of Dr. Cleary's observation that yields on Bloomberg generic long-term A-rated Canadian utility bonds (which parties agreed track the yields on Alberta utility bonds with reasonable accuracy) have been relatively stable since the time of the 2016 GCOC proceeding. According to Dr. Cleary, this stability in the overall yield was the result of an inverse relationship between interest rates (which increased) and credit spreads (which narrowed) over the period leading up to this proceeding.[518] Figure 7 in Section 6 and underlying data, support this observation and show that despite periodic short-term fluctuations, the yields on Bloomberg generic long-term A-rated Canadian utility bonds have been relatively stable with the average yield of 3.68 in 2016, 3.65 in 2017 and 3.65 in January through March of 2018.[519] As such, the Commission notes that changes in the interest rate and the utility bond credit spread appear to have offset each other to some extent.

397. Mr. Hevert's PRPM results suggested an ROE of 10.5 to 11.3 per cent for his Canadian utility proxy group and 10 per cent for his U.S. utility proxy group. The Commission observes that Mr. Hevert's Canadian PRPM ROE estimates have increased by more than 100 bps as compared to the 2016 GCOC proceeding. The U.S. results were relatively stable around 10 per cent in both the 2016 GCOC and the current proceeding.[520]

398. In the 2016 GCOC decision, the Commission assigned little weight to Mr. Hevert's PRPM analysis, in part due to the lack of record development in regard to his analysis, but expressed interest in exploring these types of models in subsequent GCOC proceedings.[521] In this proceeding, Mr. Hevert provided further explanations and support for this model.[522]

399. The Commission acknowledges Mr. Hevert's statement that the PRPM approach is relatively new,[523] and no evidence was presented by Mr. Hevert to indicate whether it has been widely accepted by other utility regulators. When asked by Commission counsel whether this approach has been adopted in any of the regulatory proceedings that Mr. Hevert or his colleagues have proposed it in, he responded that "it has not been explicitly rejected."[524] No evidence was presented regarding whether any issues with the PRPM were identified by parties in other

517 Decision 20622-D01-2016, paragraph 225.
518 Transcript, Volume 10, page 2087.
519 Commission staff calculations based on data in Exhibit 22570-X0836.
520 As summarized in paragraph 209 of Decision 20622-D01-2016, in the 2016 GCOC proceeding for the Canadian utilities proxy group, Mr. Hevert calculated the average and median risk premiums to be 7.12 per cent and 6.83 per cent, respectively. By adding these risk premiums to his recommended average risk-free rate value for Canada of 2.59 per cent, Mr. Hevert obtained ROE estimates of 9.42 per cent and 9.71 per cent. For the U.S. utilities proxy group, the calculated average and median risk premiums were 7.15 per cent and 7.06 per cent, respectively. When added to Mr. Hevert's recommended average risk-free rate value for the U.S. of 3.20 per cent, the resulting ROE estimates were 10.35 per cent and 10.26 per cent.
521 Decision 20622-D01-2016, paragraph 222.
522 Exhibit 22570-X0153.01, PDF pages 134-136.
523 Transcript, Volume 6, page 1242.
524 Transcript, Volume 6, page 1242.

proceedings where the PRPM was put forward by Mr. Hevert or his colleagues. Parties in this proceeding did not engage in any meaningful analysis of the PRPM, and as a result the Commission is unable to identify whether there are any theoretical constraints associated with using this model to develop ROE estimates for regulated utilities.

400. As parties in this proceeding did not engage in any meaningful analysis of the PRPM and no evidence was presented that the PRPM has been vetted and accepted by other utility regulators as a valid approach to estimate ROEs for regulated utilities, the Commission is not prepared to assign the PRPM any weight in this proceeding.

## 8.4 Discounted cash flow model

401. The DCF approach estimates the cost of a company's common equity based on the current dividend yield of the company's shares plus the expected future dividend growth rate. The DCF method calculates ROE as the rate of return that equates the present value of the estimated future stream of dividends to the current share price.

402. There are several types of DCF models and variations, including single-stage growth models and multi-stage growth models. Single-stage, constant growth models assume that growth in dividends will occur indefinitely at the same constant rate. Multi-stage models assume the expected dividend growth will vary over different time periods.

403. In this proceeding, both single-stage and multi-stage DCF model estimates for utility equities and the market as a whole were presented. Mr. Coyne, Dr. Cleary, Dr. Villadsen and Mr. Hevert submitted DCF model estimates for utility equities in order to directly estimate the required ROE for Alberta utilities. Dr. Cleary and Mr. Hevert submitted DCF model estimates for the market as a whole in order to gauge the reasonableness of their Alberta utilities' ROE estimates. Mr. Hevert also used his market DCF estimate to calculate his MERP estimate as noted above in Section 8.2.2.

### Discounted cash flow estimates – utility proxy groups

404. Dr. Villadsen used both single-stage and multi-stage DCF models to develop ROE estimates for her utility proxy groups.

405. In her implementation of the multi-stage DCF model, Dr. Villadsen assumed that for the first five year period, the sample companies grow their dividends at a company-specific rate of earnings growth and then taper off over a five year period to the long-term rate of growth. For the initial high growth period, Dr. Villadsen used investment analyst forecasts of company-specific growth rates sourced from Value Line and Thomson Reuters Institutional Brokers' Estimate System (IBES), which ranged from -2.0 to 15.8 per cent. For the subsequent long-term growth rate, Dr. Villadsen used a long-term Canadian GDP growth forecast of 3.85 per cent and a long-run U.S. GDP growth forecast of 4.35 per cent from *Consensus Forecasts*.[525]

[525] Exhibit 22570-X0193.01, PDF pages 72-73.

406. For her single-stage DCF model, Dr. Villadsen used investment analyst forecasts of company-specific growth rates sourced from Value Line and Thomson Reuters IBES. Excluding estimates that factor adjustments for leverage, the forecasts ranged from 8.9 to 14.8 per cent.[526]

407. Dr. Villadsen pointed out that one issue with the input data is that it only includes cash dividends and does not include share repurchases as a means to distribute cash to shareholders. To the extent that a company uses share repurchases, the input data therefore understates the cost of equity.[527]

408. Because the Commission previously expressed a preference for growth rates that do not exceed long-term GDP growth, Dr. Villadsen primarily relied on her multi-stage DCF analysis in which she estimated a range of ROEs from 8.00 to 9.75 per cent, after considering flotation costs and without considering financial risk.[528] Relative to her DCF estimates in the 2016 GCOC proceeding (9.00-11.50 per cent,)[529] Dr. Villadsen's estimates for this proceeding have a smaller range and have decreased.

409. Mr. Hevert used a single-stage DCF model and a multi-stage DCF model for his Canadian and U.S. utility proxy groups. In order to avoid any biases that may arise from anomalous or transitory events, Mr. Hevert used average market prices over 30, 90 and 180 days ending September 29, 2017, as inputs to his constant growth DCF model. For the growth rate input, Mr. Hevert used security analysts' earnings per share (EPS) growth rate forecasts. Mr. Hevert selected the maximum high and minimum low EPS growth estimates from Value Line, Zacks and First Call for each company in his proxy groups, to calculate a range of high and low ROE estimates. The results were an ROE range of 10.82-12.05 per cent, and 7.56-9.42 per cent for his Canadian and U.S. utility proxy groups, respectively, using the single-stage DCF, exclusive of flotation cost adjustments.[530] Relative to Mr. Hevert's corresponding DCF estimates in the 2016 GCOC proceeding,[531] both ROE ranges for this proceeding have decreased.

410. Mr. Hevert explained that although the model's form focuses on dividends, the growth rate also represents the assumed rate of capital appreciation, and "because dividends and price appreciation are sustained by earnings growth, the assumed growth rate should represent investors' expectations of growth in Earnings Per Share."[532]

411. Mr. Hevert acknowledged that in Decision 20622-D01-2016, the Commission did not accept growth rate estimates greater than the long-term GDP in the single-stage model. However, Mr. Hevert continued to disagree with this conclusion. Mr. Hevert argued that long-term GDP growth represents the average growth of the all sectors within the economy, and thus, should not be a ceiling for the growth component of the single-stage model. Mr. Hevert further explained that under the single stage model's assumptions, the growth rate equals the rate of capital appreciation and that, over time, capital appreciation has not been constrained by GDP growth. To demonstrate that projected EPS growth is a valid proxy for the growth rate in the constant

526 Exhibit 22570-X0193.01, PDF pages 72-75.
527 Exhibit 22570-X0193.01, PDF page 73.
528 Exhibit 22570-X0193.01, PDF page 77.
529 Decision 20622-D01-2016, Table 10.
530 Exhibit 22570-X0153.01, Table 22 and Table 23.
531 12.49-13.88 per cent for his Canadian utility proxy group, and 8.53-10.02 per cent for his U.S. utility proxy group. Decision 20622-D01-2016, paragraph 244.
532 Exhibit 22570-X0153.01, PDF page 51.

growth DCF model, Mr. Hevert conducted an analysis that found projected EPS as the only statistically significant predictor variable of the variables considered.[533]

412. Although his position remained that analysts' projections are a valid measure of growth for the constant growth DCF model, in order to address the Commission's concerns regarding the relationship between long-term earnings growth and GDP, Mr. Hevert also employed a multi-stage DCF model to address the limitations of the single-stage model.[534] Mr. Hevert explained that the multi-stage DCF can serve as a method to assess the reasonableness of its inputs by referencing certain market-based metrics.[535]

413. To apply the multi-stage method to his Canadian proxy group, Mr. Hevert applied a Canadian long-term growth rate of 5.02 per cent based on the real GDP growth rate of 3.15 per cent from 1961 through 2016, and an inflation rate of 1.82 percent. To apply the multi-stage method to his U.S. proxy group, Mr. Hevert calculated a long-term growth rate of 5.35 per cent in a manner similar to his Canadian estimate. Due to a lack of Value Line reports for companies in his Canadian proxy group, Mr. Hevert relied on current payout ratios for the first period, and the interpolated payout ratio for the second period. He then assumed that by the end of the second period (i.e., the end of year 5-10), the payout ratio would converge to each group's long-term average.[536] Applying this method, Mr. Hevert calculated results ranging from 9.77 to 10.15 per cent and 8.59 to 9.12 per cent for his Canadian and U.S. utility proxy groups, respectively.[537]

414. Mr. Hevert explained that an alternative to calculating the terminal value based on assumed GDP growth rates is to adopt one of the fundamental assumptions underlying the constant growth DCF model, that the current P/E ratio remains constant in perpetuity. Because the multi-stage model projects EPS in the terminal year, Mr. Hevert applied the current P/E ratio to the projected EPS estimate to arrive at the terminal price.[538] Applying this method, the results calculated by Mr. Hevert ranged from 9.88 to 10.76 per cent and 9.69 to 11.08 per cent for his Canadian and U.S. utility proxy groups, respectively.[539] Mr. Hevert recommended that principal weight be given to his Canadian utility proxy group DCF results that exclude sustainable growth.[540]

415. Mr. Coyne used a single-stage DCF model and a multi-stage DCF model for his three proxy groups. For his DCF analysis, Mr. Coyne calculated dividend yields for each company in his Canadian utility proxy group and for each company in his U.S. electric proxy group, by dividing the current annualized dividend by the average of the stock prices for the 90-trading-day period ending August 31, 2017. Mr. Coyne calculated the constant growth DCF model estimates using security analysts' EPS growth rate forecasts as the growth component from SNL Financial,

[533] Exhibit 22570-X0153.01, PDF page 57. Mr. Hevert conducted four separate regressions, with P/E as the dependent variable and projected EPS, dividends per share, book value per share and the sustainable growth, respectively, as the explanatory variables. Upon reviewing the results, Mr. Hevert found that the only statistically significant growth rate was projected EPS.
[534] Exhibit 22570-X0153.01, PDF pages 62-63.
[535] Exhibit 22570-X0153.01, PDF page 62.
[536] Exhibit 22570-X0153.01, PDF pages 64-65.
[537] Exhibit 22570-X0153.01, PDF page 65.
[538] Exhibit 22570-X0153.01, PDF pages 65-66.
[539] Exhibit 22570-X0153.01, PDF page 67.
[540] Exhibit 22570-X0153.01, PDF pages 6 and 56.

Value Line, Zacks and First Call for each company in the two proxy groups.[541] Similar to Mr. Hevert, Mr. Coyne explained that analysts' earnings growth estimates are typically relied on when using the DCF model.[542]

416. In order to address the limiting assumptions present in the single-stage DCF model, Mr. Coyne developed a multi-stage model to estimate ROE. In his multi-stage model, Mr. Coyne transitioned from near-term growth (i.e., the average of Value Line, Zacks, SNL Financial and First Call forecasts used in the constant growth model) for the first stage of the analysis (years 1-5), to the long-term forecast of GDP growth for the third stage of the analysis (years 11 and beyond). In his second stage, Mr. Coyne connected the near-term growth with the long-term growth for the transitional period by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows at the same rate as GDP to perpetuity (or a total of 200 years in the model).[543]

417. Mr. Coyne explained that his DCF analyses across all methods indicate an average cost of common equity of 10.24 per cent, 8.89 per cent and 9.13 per cent for his Canadian utility proxy group, U.S. electric proxy group and North American electric proxy groups, respectively, inclusive of a 50 bps adjustment for flotation costs.[544]

418. In formulating his utility single-stage DCF model estimates, Dr. Cleary derived two sustainable growth rates for each of the companies in his three proxy groups.[545] Dr. Cleary calculated results for all three of his proxy groups, using both sustainable growth rates. The resulting ROEs, excluding flotation allowance, ranged from an average of 5.01 per cent for his four company Canadian utility proxy group, to 7.24 per cent, which was the median for his seven company Canadian utility proxy group.[546] Using the mid-point of the average ROEs and the median ROEs for his three proxy groups, Dr. Cleary determined a best-estimate single-stage ROE of 5.90 per cent, excluding flotation allowance.[547]

419. Dr. Cleary also applied the multi-stage model to his three utility proxy groups. He estimated the short-term growth rate using payout ratios and ROEs from 2016. Dr. Cleary estimated the long-term growth rate using long-term averages for payout ratios and ROEs.[548] The resulting ROEs, excluding flotation allowance, ranged from an average of 6.30 per cent for his nine company Canadian utility proxy group, to 7.65 per cent for his seven company Canadian utility proxy group.[549] Dr. Cleary reported his best estimate multi-stage ROE was 6.90 per cent, excluding flotation allowance.[550]

420. Dr. Cleary weighted the best estimates of his single-stage DCF model, 5.90 per cent, and his multi-stage DCF model, 6.90 per cent, equally, to arrive at an ROE of 6.40 per cent. He added a 50 bps flotation allowance to arrive at his DCF based ROE recommendation of 6.90 per

541 Exhibit 22570-X0131, PDF page 66.
542 Exhibit 22570-X0131, PDF pages 62-63
543 Exhibit 22570-X0131, PDF page 67.
544 Exhibit 22570-X0131, PDF page 69.
545 Exhibit 22570-X0562.01, PDF pages 56-58.
546 Exhibit 22570-X0562.01, PDF page 57.
547 Exhibit 22570-X0562.01, PDF page 58.
548 Exhibit 22570-X0562.01, PDF page 58.
549 Exhibit 22570-X0562.01, Table 14.
550 Exhibit 22570-X0562.01, Table 15.

cent.[551] Dr. Cleary's DCF based ROE recommendation in the 2016 GCOC proceeding was 8.04 per cent, inclusive of a 50 bps flotation allowance.[552]

421. Mr. Hevert, Dr. Villadsen, Mr. Coyne and Dr. Cleary all exchanged critiques regarding the specific DCF models employed, the inputs used and the corresponding results.

422. In his evidence, Dr. Cleary disagreed with the utilities' experts' use of analyst earnings growth estimates because they were simply too high. He pointed out that his views were shared by the Commission in the last two GCOC decisions. Dr. Cleary highlighted that in the 2016 GCOC decision, the Commission explicitly stated that it did not accept a single-stage DCF model which uses a growth rate exceeding the long-term GDP growth rate of the economy. Dr. Cleary submitted that Dr. Villadsen's, Mr. Hevert's and Mr. Coyne's single-stage models should be rejected in this proceeding as they all violate the aforementioned condition.[553]

423. Dr. Cleary explained that a similar issue arises within Dr. Villadsen's, Mr. Hevert's and Mr. Coyne's multi-stage DCF estimates. Dr. Cleary pointed out that the implied constant perpetual growth rates used by Dr. Villadsen, Mr. Hevert and Mr. Coyne in their multi-stage DCF models exceed estimates for Canadian nominal GDP growth.[554]

424. In response to this criticism, Dr. Villadsen explained that there is no reason to believe that any one company cannot grow at a higher or lower rate than the economy in the near term. Dr. Villadsen also pointed out that the economy of Alberta is a relevant benchmark and is expected to grow faster than the overall Canadian GDP in the near future.[555] Mr. Coyne pointed out that in the 2016 GCOC decision, the Commission stated it would accept growth rates above the nominal long-term GDP growth in the initial stages of the multi-stage model.[556] Mr. Hevert responded to Dr. Cleary's criticisms by pointing out that the single-stage and multi-stage DCF models serve separate purposes and are not meant to be equivalent.[557]

425. According to Dr. Villadsen, the DCF estimates put forward by Dr. Cleary were flawed because they failed to consider the impact of share buybacks and, therefore, underestimated the expected market returns. Dr. Villadsen expressed her disagreement with the use of the historic average Canadian GDP growth rate as a long-term growth rate because it is a backward-looking metric that is conceptually flawed and inconsistent with the underlying principles of the model.[558]

426. Regarding Dr. Cleary's multi-stage estimates, Dr. Villadsen took issue with the use of Canadian GDP growth in 2023-2027 from *Consensus Forecasts* as the short-term growth rate and the use of historical GDP growth over an arbitrarily chosen period for the long-term growth input, without justification as to why these inputs were used in the model.[559] Dr. Villadsen also pointed out that while Dr. Cleary criticized *Consensus Forecasts* for predicting government

[551] Exhibit 22570-X0562.01, PDF page 60.
[552] Decision 20622-D01-2016, paragraph 256.
[553] Exhibit 22570-X0562.01, PDF pages 62-63.
[554] Exhibit 22570-X0562.01, PDF page 64.
[555] Exhibit 22570-X0562.01, PDF page 63.
[556] Exhibit 22570-X0562.01, PDF page 42.
[557] Exhibit 22570-X0890.01, PDF page 73.
[558] Exhibit 22570-X0767.01, PDF page 63.
[559] Exhibit 22570-X0767.01, PDF page 57.

yields above what occurred since the last GCOC, Dr. Cleary used their estimates for future GDP growth.[560]

427. Mr. Coyne critiqued Dr. Cleary's dismissal of analyst growth rates and his derivation of the sustainable growth rate in his multi-stage model. Mr. Coyne pointed out that Dr. Cleary's derivation of the sustainable growth rate is incomplete and understates the applicable growth rate. Mr. Coyne explained that Dr. Cleary's derivation assumes that utilities will not issue new financing to support growth, and that in order to properly calculate the sustainable growth rate, long-term expected stock financing should be factored into the equation. Mr. Coyne also pointed out that an additional issue with this formulation is that it requires ROE as an input, creating a circularity problem.[561] Mr. Hevert pointed out that Dr. Cleary's recommended growth rates are unreasonable and, since they are below the Bank of Canada's target inflation of two per cent, are negative in terms of real growth.[562]

428. The UCA highlighted that Dr. Cleary did not dispute that some of his growth rates would imply a negative real rate of return; however, he stressed that other factors, such as stable dividends, might attract investors.[563]

429. In response to Dr. Cleary's view that regulated utilities should be expected to grow at a slower pace than the overall GDP, Mr. Coyne developed a comparison of actual earnings and dividends per share growth rates for his three proxy groups and highlighted that both earnings and dividend growth exceeded GDP growth by a wide margin during the period analyzed.[564]

430. Consistent with the other utility witnesses, Mr. Hevert explained that Dr. Cleary's DCF estimates are understated largely because of his reliance on sustainable growth rate estimates. Mr. Hevert explained that contrary to the premise of sustainable growth, which Dr. Cleary applied, empirical research has demonstrated that higher growth is associated with higher payout ratios.[565]

431. A summary of the DCF models ROE results are included in Table 5 below.

[560] Exhibit 22570-X0767.01, PDF pages 57-58.
[561] Exhibit 22570-X0562.01, PDF page 36.
[562] Exhibit 22570-X0890.01, PDF page 75.
[563] Exhibit 22570-X0897.01, PDF page 47.
[564] Exhibit 22570-X0775, PDF pages 44-45.
[565] Exhibit 22570-X0741.01, PDF pages 51-52.

**Table 5. ROE results determined using various DCF models, including flotation allowance**

| | ROE 2018 GCOC | ROE 2016 GCOC[566] |
|---|---|---|
| | (%) | |
| Dr. Villadsen-recommendation-without leverage[567] | 8.00-9.75 | 9.00-11.50 |
| Mr. Hevert-Canadian utility proxy group-single-stage[568] | 11.32-12.55 | 12.99-14.38 |
| Mr. Hevert-Canadian utility proxy group-multi-stage[569] | 10.27-10.65 | N/A |
| Mr. Hevert-U.S. utility proxy group-single-stage[570] | 8.06-9.92 | 9.03-10.52 |
| Mr. Hevert-U.S. utility proxy group-multi-stage[571] | 9.09-9.62 | N/A |
| Mr. Coyne-Canadian utility proxy group-single-stage[572] | 10.85 | N/A |
| Mr. Coyne-Canadian utility proxy group-multi-stage[573] | 9.63 | N/A |
| Mr. Coyne-U.S electric proxy group-single-stage[574] | 9.11 | N/A |
| Mr. Coyne-U.S electric proxy group-multi-stage[575] | 8.66 | N/A |
| Mr. Coyne-North American electric proxy group-single-stage[576] | 9.47 | N/A |
| Mr. Coyne-North American electric proxy group-multi-stage[577] | 8.79 | N/A |
| Dr. Cleary-recommendation[578] | 6.90 | 8.04 |

### Discounted cash flow estimates – Canadian and U.S. equity markets

432. Dr. Cleary, Mr. Coyne and Mr. Hevert each provided single-stage DCF ROE estimates for the overall equity market. Dr. Cleary also utilized a multi-stage DCF model for this purpose. Dr. Cleary and Mr. Hevert used the results to gauge the reasonableness of their ROE estimates. Mr. Hevert and Mr. Coyne used their results to calculate their MERP estimates.

433. Dr. Cleary equally weighted the results of his single-stage and multi-stage results, and provided a best estimate for the Canadian market required ROE of 7.70 per cent.[579] This is lower than the 8.75 per cent figure he presented in the 2016 GCOC decision.[580]

434. Mr. Hevert calculated estimated total returns of 14.84 per cent and 13.83 per cent for the S&P/TSX and S&P 500, respectively.[581] In the 2016 GCOC decision, the results presented by Mr. Hevert were 12.65 per cent and 13.78 per cent for the S&P/TSX and S&P 500, respectively.[582]

566 Decision 20622-D01-2016, Table 10.
567 Exhibit 22570-X0767.01, PDF page 77.
568 Exhibit 22570-X0153.01, Table 22.
569 Exhibit 22570-X0153.01, Table 22.
570 Exhibit 22570-X0153.01, Table 23.
571 Exhibit 22570-X0153.01, Table 23.
572 Exhibit 22570-X0131, Table 15.
573 Exhibit 22570-X0131, Table 15.
574 Exhibit 22570-X0131, Table 15.
575 Exhibit 22570-X0131, Table 15.
576 Exhibit 22570-X0131, Table 15.
577 Exhibit 22570-X0131, Table 15.
578 Exhibit 22570-X0562.01, PDF page 61.
579 Exhibit 22570-X0562.01, PDF page 54.
580 Decision 20622-D01-2016, paragraph 252.
581 Exhibit 22570-X0153.01, PDF page 66.
582 Decision 20622-D01-2016, paragraph 243.

435. Mr. Coyne calculated an estimated total return of 12.64 per cent and 12.74 per cent for the S&P/TSX and S&P 500, respectively.[583]

436. Dr. Cleary was the only expert to use a multi-stage model to estimate the market return. Mr. Hevert critiqued Dr. Cleary's estimates as too conservative, pointing out that sustainable growth is an inferior measure of expected growth.[584]

**Commission findings**

437. The Commission was presented with ROE estimates determined using both single-stage and multi-stage DCF models.

438. With respect to the single-stage DCF model estimates presented by Dr. Villadsen, Mr. Coyne and Mr. Hevert, the growth rates used by each of these three witnesses in their single-stage DCF models are in excess of the long-term GDP growth estimates they put forward.[585] Consistent with its determinations in prior GCOC decisions, the Commission will not accept, in a single-stage DCF model, the use of long-term or terminal growth rates that exceed estimates of the nominal long-term GDP growth rate for the economy. The Commission recognizes that the utilities are, as Dr. Cleary stated in his evidence, 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.[586]

439. With regard to the single-stage DCF model results submitted by Dr. Cleary, the Commission notes that the implied overall average long-term growth rate across his 12 scenarios was 1.89 per cent.[587] The Commission notes that this growth rate is within the Bank of Canada's targeted range of one to three per cent for inflation. If long-term inflation exceeds Dr. Cleary's 1.89 per cent long-term growth rate, this results in negative real growth. The Commission considers that over the long term, investors would not accept the risks of equity ownership if the expected long-term outlook for real growth was at or near negative levels. Consequently, the Commission will not accept the single-stage DCF model results submitted by Dr. Cleary.

440. With regard to the multi-stage DCF ROE estimates submitted by Dr. Cleary, Dr. Villadsen, Mr. Coyne and Mr. Hevert, there was disagreement among the witnesses regarding whether it is acceptable to use growth rates above the nominal long-term GDP growth rate, in the initial stages of a multi-stage DCF model. In the 2016 GCOC decision, the Commission accepted that in some circumstances, the use of growth rates above the nominal long-term GDP growth rate may be reasonable in the initial stages.[588]

441. In this proceeding, Dr. Villadsen contended that there is no reason to believe that any one company cannot grow at a higher rate than the economy in the near term. She noted that Alberta's economy is expected to grow faster than the Canadian GDP in the near future.[589] The Commission agrees with these submissions of Dr. Villadsen, and therefore, it will accept the use

583 Exhibit 22570-X0132, worksheets JMC-3 Canada MRP and JMC-4 US MRP.
584 Exhibit 22570-X0741.01, PDF page 51.
585 Exhibit 22570-X0562.01, Table 16.
586 Exhibit 22570-X0562.01, PDF page 63.
587 Exhibit 22570-X0562.01, Table 13, average of 1.92 per cent and 1.86 per cent.
588 Decision 20622-D01-2016, paragraph 287.
589 Exhibit 22570-X0767.01, A78.

of growth rates above the nominal long-term GDP growth rate, in the initial stages of the multi-stage DCF models used by Dr. Villadsen, Mr. Coyne and Mr. Hevert.

442. On the subject of the long-term growth rates used in the multi-stage DCF models, Mr. Hevert used 5.02 per cent for Canada and 5.35 per cent for the U.S. He developed these estimates using real historical GDP growth rates.[590] Dr. Villadsen and Mr. Coyne used long-term growth rates of 3.85 per cent and 3.84 per cent, respectively, for Canada.[591] For the U.S., Dr. Villadsen and Mr. Coyne used a long-term growth rate of 4.35 per cent.[592] Dr. Villadsen's and Mr. Coyne's long-term growth rates were developed using information from *Consensus Forecasts*.[593]

443. The Commission notes that Mr. Hevert's long-term estimates are grounded in historical data, whereas the *Consensus Forecast* long-term growth rate forecasts are forward looking. The Commission finds that historical growth rates, developed over a 55-year period,[594] might not be a valid indicator or a fair representation of future growth. Consequently, the Commission prefers the multi-stage DCF models of Dr. Villadsen and Mr. Coyne because these use forward-looking, long-term growth estimates.

444. Mr. Hevert criticized the growth rates that Dr. Cleary used in his multi-stage DCF model. Mr. Hevert described them as being "unduly low."[595] The Commission notes that the implied overall average long-term growth rate across Dr. Cleary's six scenarios was 2.83 per cent.[596] The Commission considers that this long-term growth rate is within the Bank of Canada's targeted range of one to three per cent for inflation. However, as noted above, if long-term inflation exceeds Dr. Cleary's 2.83 per cent long-term growth rate, this results in negative real growth. Again, the Commission considers that over the long term, investors would not accept the risks of equity ownership if the expected long-term outlook for real growth was at or near negative levels. Consequently, the Commission will not accept the multi-stage DCF model results submitted by Dr. Cleary.

445. The Commission finds that both Mr. Coyne's and Mr. Hevert's estimates of the expected Canadian and U.S. market returns using the DCF model, which range from 12.65 to 14.84 per cent, are too high. These results are driven by unreasonable growth rate estimates. The Commission observes that the basis of Mr. Coyne's estimate of the Canadian market return relied on a sample with approximately 14 per cent of the companies having growth rates that exceeded 20 per cent.[597] Turning to Mr. Hevert's estimate of the Canadian market return, approximately 16.5 per cent of the companies in his sample had growth rates that exceeded 20 per cent.[598] Considering that the single-stage DCF model assumes a growth rate into perpetuity, the Commission finds the resulting estimate unrealistic, and affords Mr. Hevert's and Mr. Coyne's equity market DCF estimates no weight. In addition, the Commission notes that the expected market return rates used by Mr. Coyne and Mr. Hevert use analyst estimates of growth

590 Exhibit 22570-X0153.01, PDF page 64.
591 Exhibit 22570-X0193.01, A68. Exhibit 22570-X0131, Table 14.
592 Exhibit 22570-X0193.01, A68. Exhibit 22570-X0131, Table 14.
593 Exhibit 22570-X0193.01, A68. Exhibit 22570-X0131, PDF page 68.
594 Exhibit 22570-X0153.01, PDF page 64.
595 Exhibit 22570-X0741.01, PDF page 30.
596 Exhibit 22570-X0562.01, Table 14, using the average of 2.42 per cent, 3.57 per cent, and 2.51 per cent.
597 Exhibit 22570-X0132, Sheet JMC-3 Canada MRP.
598 Exhibit 22570-X0154.01, Sheet Sch 6 MRP TSX.

rates that far exceed GDP growth. Accordingly, the Commission finds that the expected market return rates put forward by Mr. Coyne and Mr. Hevert are too high. No meaningful evidence was provided that would enable the Commission to quantify the extent of the over-estimation in order to develop a more reasonable estimate.

446. Given the foregoing, the Commission finds that the resulting range of ROE estimates is 8.00 to 9.75 per cent, which is the recommended range of Dr. Villadsen, consisting of the 8.00 per cent ROE estimate for her U.S. gas LDC utility proxy group, and the 9.75 per cent ROE estimate for her Canadian utility proxy group, to be reasonable. However for reasons discussed further below, the Commission finds Dr. Villadsen's recommended range to be biased upward. The Commission also notes that Mr. Coyne's three multi-stage estimates all fall within this range.

447. The 9.75 per cent upper end of Dr. Villadsen's ROE estimate from her multi-stage DCF model is based on the results from her Canadian utility proxy group, which consists of nine companies. The growth rate used in the initial stage of her multi-stage DCF model for three of the companies in her Canadian utility proxy group is in excess of 14.00 per cent, while the initial growth rates for the other six companies range from 2.60 to 7.48 per cent, and average 4.98 per cent. Accordingly, the Commission considers that the results of Dr. Villadsen's multi-stage DCF model for her Canadian utility proxy group are skewed upward because of the use of growth rates that exceed 14.00 per cent, in combination with the small number of companies included in this proxy group.

448. The 9.63 per cent ROE estimate from Mr. Coyne's multi-stage DCF model for his Canadian utility proxy group suffers from the same issue as Dr. Villadsen's result of 9.75 per cent. Mr. Coyne's Canadian utility proxy group consists of five companies, and includes an average initial growth rate estimate of 5.96 per cent. However, there are two companies in this proxy group that have initial growth rates in excess 8.25 per cent, which is over 38 per cent above the average of 5.96 per cent. The Commission considers that including these two companies in such a small proxy group significantly skews the results upward.

449. The Commission considers that the 8.79 per cent ROE estimate from Mr. Coyne's multi-stage DCF model for his North American electric proxy group, which excludes one of the Canadian companies that had a growth rate in excess of 8.25 per cent, and includes all of the companies from his U.S. electric proxy group, largely mitigates the issue regarding the outcomes associated with the use of higher than average initial growth rates and small proxy group sizes. Accordingly, the Commission finds that 8.79 per cent is a reasonable point estimate for the multi-stage DCF method.

## 8.5 Stock market return expectations of finance professionals

450. The Commission has indicated in previous GCOC decisions that it will consider evidence regarding return expectations of market professionals in determining a fair ROE for the regulated utilities in Alberta. However, the Commission gave little weight to this information in Decision 20622-D01-2016 because the referenced reports and articles, with one exception, predated the

2016 GCOC proceeding, making it unclear whether the expressed expectations reflected the current expectations of market professionals at the time of that proceeding.[599]

451. Consistent with his evidence from past GCOC proceedings, Dr. Cleary recommended consideration of the return expectations of market professionals in determining the fair ROE. He stated that beliefs of professionals participating in the markets and influencing market activity are far more relevant than market expectations developed by utilities' experts. To this end, Dr. Cleary provided data showing historical long-term real returns for Canadian equity markets. This data suggested average real returns of 6.55 per cent for Canada, with a range of estimates from 5.6 to 7.4 per cent over approximately the last 100 years. Combining these figures with expected inflation of two per cent would suggest expected nominal returns of 8.55 per cent, with a range of estimates from 7.6 to 9.4 per cent based solely on long-term historical results.

452. Dr. Cleary also provided 2017 publications from several sources[600] that expressed an expectation of long-term market returns for Canada in the nominal range of 4.0 to 8.1 per cent, with an average of 5.83 per cent. In response to a Commission IR, Dr. Cleary provided updated numbers for some of these reports; however, he confirmed that the updated documents do not alter his conclusions.[601] Dr. Cleary then subtracted an expected inflation rate of 2.0 per cent to arrive at an average real return of 3.83 per cent, which he pointed out was below the long-term average for the Canadian market:

> Deducting the 2% expected inflation, this translates to an average real return of 3.83%. In other words, most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term real rates of return in the 5.6-7.4% range over the next 5-10 years, with most of them citing the current low interest rate environment as one of the main contributing factors.[602]

453. Dr. Cleary expressed his view that both historical returns and current expectations of market professionals represent the best sources of information regarding future long-term market returns. Combining the historical returns and market forecasts for Canada, Dr. Cleary arrived at a market return range of 6-9 per cent, with a midpoint of 7.5 per cent.[603]

454. In reference to the return expectations by market professionals provided by Dr. Cleary, Mr. Coyne stated that such data is conservative and targeted for pension fund managers, and while he saw no reason not to consider this information, he submitted that he would not place primary reliance on this data.[604]

455. Mr. Hevert did not share the view that return expectations of market professionals should be considered when determining a fair ROE for the Alberta utilities. In addition to pointing out that the Commission in previous GCOC decisions indicated that pension fund managers tend to be somewhat conservative, Mr. Hevert noted that fund managers must consider a measure of *expected* returns, whereas the cost of equity is a measure of investors' *required* returns.

599 Decision 20622-D01-2016, paragraph 297.
600 The Financial Planning Standards Council; consulting firms such as AON Hewitt and McKinsey; and several investment management firms such as CIBC Asset Management, BlackRock, etc.
601 Exhibit 22570-X0675, UCA-AUC-2018JAN26-004, PDF page 9.
602 Exhibit 22570-X0562.01, PDF page 36.
603 Exhibit 22570-X0562.01, PDF page 36.
604 Transcript, Volume 5, pages 976- 977.

> A pension fund asset manager will match the expected returns available from various asset classes to the expected liabilities that must be funded. An investor seeking to maximize his risk-adjusted return will only invest in a security if the expected return is equal to or greater than the required return. If it is not, the investor will look to alternative investments for which the expected return is compensatory relative to the expected risks. Because expected returns may or may not equal required returns, it is not clear that pension funding assumptions (that is, expected returns) should be viewed as a measure of investors' required returns.[605]

456. To understand whether the use of market expected returns is an approach endorsed by the finance industry, Mr. Hevert conducted a review of articles published in financial journals, as well as various texts. Mr. Hevert's review showed that analyses of expected market returns, or pension fund assumptions, were not among the analytical techniques used by the authors in the determination of the cost of capital.[606] Mr. Thygesen questioned Mr. Hevert's conclusion by pointing out that the mere absence of applying market expected returns by the authors does not mean that the approach is irrelevant.[607]

457. Mr. Hevert pointed out that several of the documents relied upon by Dr. Cleary "contain clearly stated limiting assumptions and disclaimers, which call into question their use for the purpose of setting the ROE in this proceeding."[608] Mr. Hevert also expressed the view that in establishing their return requirements, investors use the growth rate projections by analysts that cover the individual stocks rather than broad market projections like those provided by Dr. Cleary. Mr. Hevert concluded his rebuttal evidence on this subject with a reference to 2017 Duke Chief Financial Officer survey results projecting average and median hurdle rates of 17.44 per cent and 15.00 per cent, respectively, in Canada, and 13.50 per cent and 12.0 per cent in the U.S.[609]

458. In a similar vein, Mr. Buttke submitted that long-term market aggregate expectations should not be assumed to be similar to investors' required equity returns. In Mr. Buttke's view, this relationship presumes that investors (including pension funds) passively invest in a given country's market indices, are willing to accept the public market's aggregate return over the long term and do not make any dynamic market decisions. Accordingly, it is inferred that Canadian equity market investors are unable to purchase equities from other comparable markets with higher long-term expected returns. Given the global nature of capital markets, Mr. Buttke concluded that it is not supportable to assume that a local expected return would define investors' hurdle rates.[610]

459. At the hearing, Dr. Villadsen added that it is very difficult to sample all relevant information and it can be challenging to figure out what is representative of the market.[611]

605 Exhibit 22570-X0153.01, PDF page 88.
606 Exhibit 22570-X0153.01, PDF pages 88-90.
607 Exhibit 22570-X0551, paragraph 206.
608 Exhibit 22570-X0741.01, PDF page 44.
609 Exhibit 22570-X0741.01, PDF page 25.
610 Exhibit 22570-X0749, PDF pages 98-99.
611 Transcript, Volume 4, page 652.

**Commission findings**

460. Consistent with its determinations in previous GCOC decisions, the Commission continues to hold the view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities, while keeping in mind the purpose and limitations of such estimates.

461. Regarding Mr. Hevert's point that fund managers must consider a measure of expected returns, whereas the cost of equity is a measure of investors' required returns, the Commission has discussed in Section 4 of this decision that one of the elements of the fair return standard is investments with comparable risk. The Commission considers that the expected returns for the equity market as a whole provide a useful reasonableness check for the fair return established for the affected utilities. In Decision 2004-052, the board determined that it is reasonable to "expect the required return for utilities to be below the required overall equity market return,"[612] given that investments in utility stocks are typically less risky than investments in the average company stock in the market. The Commission agrees.

462. The Commission also acknowledges Mr. Buttke's view with respect to the relationship between capital markets and the option for investors to seek alternatives in markets with higher expected returns than available in Canada. In previous GCOC decisions, the Commission communicated that in determining a fair return for Alberta utilities, it is reasonable to rely on the U.S. market return data given the globalization of the world economy and the integration of North American capital markets.[613]

463. Notwithstanding that the market return expectations of finance professionals may be of some informational value in the determination of a fair ROE for regulated utilities, in this proceeding the evidence received was of little assistance to the Commission for the following reasons.

464. Mr. Hevert provided data showing hurdle rates in the range of some 15 to 17 per cent in Canada, and 12 to 13 per cent in the U.S. In Decision 2191-D01-2015, the Commission agreed with those parties who stated that caution needs to be exercised when comparing hurdle rates to the cost of equity estimates. This is because hurdle rates are often project-specific, whereas the objective of the ROE estimation models (and a GCOC proceeding in general) is to estimate the cost of capital for the company as a whole.[614] Further, the Commission finds the results of Mr. Hevert's review of financial journals do not lead to the conclusion that expected market returns and pension fund assumptions are not relevant in the determination of cost of capital.

465. In the 2016 GCOC decision, the Commission expressed concerns with the potential suitability of the reports cited by the intervener witnesses because only one report was published since the time of the 2013 GCOC decision. In the current proceeding, Dr. Cleary addressed this concern and presented reports published in 2017. The Commission takes note of Dr. Cleary's statement that "most market professionals are of the belief that Canadian stocks are unlikely to earn their historic long-term rates of return in the 5.6-7.4% range over the next 5-10 years, with most of them citing the current low interest rate environment as one of the main contributing

[612] Decision 2004-052, page 29.
[613] Decision 20622-D01-2016, paragraph 302 with reference to Decision 2009-16, paragraph 200.
[614] Decision 2191-D01-2015, paragraph 69.

factors."[615] Dr. Cleary used this information, along with the historical market returns, to arrive at his point estimate of 7.5 per cent return for the Canadian market.

466. The Commission finds that Dr. Cleary's point estimate of 7.50 per cent for the expected Canadian market return is too low. Subtracting Dr. Cleary's risk-free rate recommendation of 2.60 per cent from his point estimate of 7.50 per cent, results in a MERP of 4.90 per cent. The Commission finds that this is much lower than the suggested minimum MERP value of 6.89 per cent, as discussed in Section 8.2.2, and the Commission's MERP value of seven per cent it used in determining its CAPM point estimate. Accordingly, the Commission will not place any weight on Dr. Cleary's point estimate of 7.50 per cent for the expected Canadian market return, in determining the approved ROE.

## 8.6 Flotation allowance

467. ROE estimates obtained through CAPM, DCF or risk premium models are usually adjusted upward by a "flotation allowance" or "flotation costs." The Commission noted in previous GCOC decisions that a flotation allowance is normally included in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution.[616] In the 2016 GCOC decision, the Commission found that a flotation allowance of 50 bps was reasonable and consistent with the historical practice of the Commission and its predecessor.

468. In this proceeding, Dr. Villadsen,[617] Mr. Hevert,[618] Mr. Coyne[619] and Dr. Cleary[620] adopted the 0.50 per cent flotation costs adjustment allowed by the Commission in previous GCOC decisions, including the most recent Decision 20622-D01-2016.[621]

### Commission findings

469. The Commission finds that a flotation allowance of 0.50 per cent continues to be reasonable and will accept this adjustment to the ROE results obtained through CAPM, DCF or risk premium models.

## 8.7 Other considerations in establishing a fair approved return on equity

470. In addition to the models and information discussed in previous sections of this decision, parties employed other considerations in arriving at their recommendations regarding a fair ROE for the Alberta utilities.

471. Dr. Villadsen indicated that because investors compare returns across jurisdictions, it is important to recognize the ROE and capital structures that utilities have recently been granted in other jurisdictions.[622] Therefore, she presented information on the approved ROE and capital structure for other Canadian and U.S. utilities for 2016 and 2017. Dr. Villadsen stated it is clear

615 Exhibit 22570-X0562.01, PDF page 36.
616 Decision 2011-474, paragraph 68. Decision 2009-216, paragraph 255.
617 Exhibit 22570-X0193.01, PDF page 8.
618 Exhibit 22570-X0153.01, PDF page 101.
619 Exhibit 22570-X0131, PDF page 69.
620 Exhibit 22570-X0562.01, PDF pages 49, 61 and 67.
621 Decision 20622-D01-2016, paragraph 157.
622 Exhibit 22570-X0193.01, PDF page 77.

that the approved ROE both in Canada and the U.S. has been substantially higher than the ROE awarded by the Commission in the 2016 GCOC decision. She noted that the average deemed equity ratio is in the range of 40 to 50 per cent. Excluding Crown corporations, the approved ROE elsewhere in Canada is approximately 9.3 per cent, and the deemed equity ratios have averaged approximately 40 per cent.[623]

472. In presenting her ROE recommendations, and recognizing that the cost of equity depends on the leverage of the company to which it is applied, Dr. Villadsen considered the difference in leverage between the data she used to estimate the cost of equity and a benchmark equity percentage. Using the established techniques (such as the Modigliani-Miller and Hamada adjustments),[624] Dr. Villadsen adjusted her ROE estimates for leverage and presented both the adjusted and unadjusted recommendations. Mr. Hevert raised a similar point in his evidence.[625]

473. Dr. Cleary presented evidence on the relevance of market P/B ratios in assessing the cost of equity. Dr. Villadsen submitted that consistent with her position in the 2016 GCOC, she finds information on P/B ratios to be problematic.[626] In her rebuttal evidence, Dr. Villadsen provided further critique of Dr. Cleary's evidence on P/B values and their relevance to the fair ROE.[627]

### Commission findings

474. As previously discussed in Section 4, the Commission will not take any guidance from the evidence presented about approved utility ROEs in other Canadian and U.S. jurisdictions. The objective of the GCOC is to consider the market expectation for the affected utilities and not what other regulators are allowing.

475. In Decision 20622-D01-2016, the Commission considered the relationship between capital structure and ROE and techniques to account for financial risk by adjusting for leverage, such as the Modigliani-Miller and Hamada models. The Commission concluded that "As a consequence of the uncertainty created by the number of untested assumptions as well as the lack of sensitivity analysis provided for some of the models, the Commission will not employ any of these suggested models in its determination of the deemed equity ratios or the approved ROE in this proceeding except to illustrate that a relationship exists."[628]

476. The Commission has not been persuaded to depart from these earlier findings. In this proceeding, Mr. Hevert appears to have come to a similar conclusion when he stated:

> Please note that although the Modigliani-Miller and Hamada adjustments may be used to generally measure the magnitude of the effect of incremental increases in leverage on the Cost of Equity, it is important to recognize the results are imprecise due to the complex and the dynamic nature of the relationship. It also is important to keep in mind that any measure of an "optimal" capital structure must consider numerous objectives and constraints. Nonetheless, the analytical results are consistent with the proposition that increasing financial leverage increases the Cost of Equity.[629]

623 Exhibit 22570-X0193.01, PDF page 78.
624 Refer to Exhibit 22570-X0192.01, PDF pages 38-42.
625 Exhibit 22570-X0153.01, PDF pages 105-108.
626 Exhibit 22570-X0193.01, PDF page 79.
627 Exhibit 22570-X0767.01, PDF pages 72-74.
628 Decision 20622-D01-2016, paragraph 101.
629 Exhibit 22570-X0153.01, PDF pages 107-108.

477. Dr. Villadsen adjusted her overall ROE recommendation somewhat in recognition of the Commission's preference for results that do not take leverage into account.[630]

478. With respect to the relevance of P/B ratios, the Commission notes that the experts disagreed on the merits of using these ratios in assessing the cost of equity. The Commission further notes that no new transactions affecting Alberta utilities have been cited in evidence since the 2013 GCOC proceeding for the Commission to consider. Consistent with the 2016 GCOC decision,[631] the Commission has not given any weight to P/B ratio evidence in this proceeding.

## 8.8 Conclusions on ROE

479. The Commission has been presented with a wide range of recommended ROEs as set out in Table 6 below.

**Table 6. ROE recommendations presented**

| | Recommended by Mr. Hevert [632] | Recommended by Dr. Villadsen[633] | Recommended by Dr. Cleary[634] | Recommended by Mr. Coyne[635] |
|---|---|---|---|---|
| | (%) | | | |
| 2018 | 9.00 – 10.75 | 10.00 | 6.30 | 9.50 |
| 2019 | 9.00 – 10.75 | 10.00 | 6.30 | 9.50 |
| 2020 | 9.00 – 10.75 | 10.00 | 6.30 | 9.50 |

480. Mr. Hevert, on behalf of AltaLink, EPCOR and FortisAlberta, arrived at his recommended ROE range of 9.00 to 10.75 per cent, giving primary weight to his Canadian utility proxy group and, within that group, giving principal weight to the DCF model-based results, with less weight given to the CAPM and risk premium based methods. Mr. Hevert submitted that his recommendations consider higher levels of current and expected growth, increased short-term rates, normalization of monetary policy, a continued increase in utility bond yields and increased risk, as measured by Bloomberg's beta coefficients.[636]

481. Dr. Villadsen, on behalf of the ATCO Utilities and AltaGas, recommended an approved ROE in the range of 9.50 to 10.50 per cent, with 10.00 per cent as a reasonable point estimate. Dr. Villadsen stated that this value was supported by her Canadian utility proxy group, her U.S. gas LDC utility proxy group, and her U.S. water utility proxy group, before any consideration of financial risk.[637] Dr. Villadsen submitted that it was preferable to consider the ROE estimates using multiple methods, consistent with the approach taken by other provincial regulators. Dr. Villadsen based her recommendation on the results from her CAPM, single- and multi-stage

630 Exhibit 22570-X0193.01, PDF page 80.
631 Decision 20622-D01-2016, paragraph 305.
632 Exhibit 22570-X0153.01, PDF page 131.
633 Exhibit 22570-X0193.01, PDF page 99.
634 Exhibit 22570-X0562.01, PDF page 6.
635 Exhibit 22570-X0562.01, PDF page 117.
636 Exhibit 22570-X0153.01, PDF page 97.
637 Exhibit 22570-X0193.01, PDF page 99.

DCF models, and considering the business risk analysis of Dr. Carpenter and Mr. Buttke's submissions on relevant changes in global economic and Canadian capital market conditions. [638]

482. Dr. Cleary, on behalf of the UCA, recommended an ROE of 6.3 per cent. In making this recommendation, he gave equal weight to his CAPM, DCF and BYPRPM estimates. Dr. Cleary noted that his results were reasonable compared to expected long-term market returns in the 6.00 to 9.00 per cent range, and the low-risk nature of regulated utilities.[639]

483. Mr. Coyne, on behalf of ENMAX, recommended an approved ROE of 9.50 per cent as a reasonable point estimate. Mr. Coyne's recommendation was based on the CAPM and DCF model results for all three of his proxy groups, with greater weight placed on the results of his North American electric proxy group and his Canadian utility proxy group.[640]

484. Mr. Thygesen, on behalf of the CCA, recommended an ROE of 7.75 per cent. Rather than develop his recommendation using financial models, Mr. Thygesen compared the affected utilities' average actual ROE of 9.44 per cent for 2014 to 2016, to the average actual ROE of 8.90 per cent for the same period, for the companies in Mr. Hevert's U.S. utility proxy group. Mr. Thygesen noted the resulting difference of 54 bps and he stated that a downward adjustment to the approved ROE for 2014 to 2016 of 8.30 per cent[641] would be required to bring the ROE of the affected utilities to the level of comparable investments.[642]

485. The Commission finds Mr. Thygesen's recommended ROE, which is only based on a comparison of average actual ROEs achieved over a three-year period between utilities in Alberta and the U.S. is not a reasonable method to establish approved ROEs for the affected utilities for 2018 to 2020. His comparison lacks the detailed analysis that should be performed to identify the reasons why the actual ROEs achieved by the companies in Mr. Hevert's U.S. utility proxy group were different than the ROEs achieved by the affected utilities over the same period. Accordingly, the Commission will place no weight on Mr. Thygesen's recommendation in determining the approved ROE.

486. Turning to the ROE estimates presented using the CAPM, the Commission found in Section 8.2.4 that the wide range of CAPM results does not, on its own, provide much assistance to the Commission in determining an approved ROE. Further, the relatively wide range of betas, and interest rates still being lower relative to average historical rates, continue to be factors that will lead the Commission to assign relatively less weight to the CAPM ROE results. Nonetheless, the Commission has determined a point estimate of 7.90 per cent with respect to the CAPM, which it will consider to establish an approved ROE.

487. Regarding the ECAPM, the Commission found in Section 8.2.5 that different empirical adjustment factors may need to be employed when applied to adjusted betas or, conversely, unadjusted betas may need to be employed in any future ECAPM that relies on the empirical adjustment factors used by Dr. Villadsen and Mr. Hevert, and that other modifications to the empirical ECAPM adjustment coefficients may be required, unique to regulated utilities. The

638 Exhibit 22570-X0193.01, PDF pages 11-12.
639 Exhibit 22570-X0562.01, PDF pages 74-75.
640 Exhibit 22570-X0131, PDF page 10.
641 Exhibit 22570-X0701.01, CCA-AUC-2018JAN26-019.
642 Exhibit 22570-X0551, paragraphs 120-129.

Commission remains of the view expressed in the 2016 GCOC decision that the empirical adjustment factor in ECAPM does not resolve the issue with respect to the wide range of estimated betas. As a result, the Commission will not assign significant weight to the ECAPM results in this proceeding. The Commission considers it preferable to improve the CAPM results by way of multi-factor models that specifically aim to identify factors explaining the required return, if possible, rather than using empirical adjustment factors as is done under the ECAPM.

488. With respect to the BYPRPM, the Commission found in Section 8.3 that this approach is a valid tool in estimating the cost of equity as it is simple to use, incorporates readily observable, market-determined data (such as bond returns and yields), and conforms to the basic principle that investors require a higher return for assets with greater risk. However, the BYPRP models presented in this proceeding falter in their application of the equity risk premium adder to the bond yield. Accordingly, the Commission did not place any weight on the results of the BYPRP models presented by Dr. Cleary, Mr. Hevert or Mr. Coyne. The Commission did, however, take note of Dr. Cleary's observation that yields on Bloomberg generic long-term A-rated Canadian utility bonds (which parties agreed track the yields on Alberta utility bonds with reasonable accuracy) have been relatively stable since the time of the 2016 GCOC proceeding, and that this stability in the overall yield was the result of an inverse relationship between interest rates (which increased) and credit spreads (which narrowed) over the period leading up to this proceeding. This led the Commission to note that changes in the interest rate and the utility bond credit spread appear to have offset each other to some extent.

489. The Commission also found in Section 8.3 that without any meaningful analysis of the PRPM on the record of this proceeding, and without any evidence being presented that the PRPM has been vetted and accepted by other utility regulators as a valid approach to estimate ROEs for regulated utilities, the Commission is not prepared to assign the PRPM any weight in this proceeding.

490. Regarding the DCF models presented, the Commission indicated in Section 8.4 that it preferred the multi-stage models of Dr. Villadsen and Mr. Coyne because they use forward-looking long-term growth estimates. The Commission considers that the 8.79 per cent ROE estimate from Mr. Coyne's multi-stage DCF model for his North American electric proxy group, which excludes one of the Canadian companies that had a growth rate in excess of 8.25 per cent, and includes all of the companies from his U.S. electric proxy group, largely mitigates the issue regarding the outcomes associated with the use of high growth rates and small proxy group sizes. Accordingly, the Commission found that 8.79 per cent is a reasonable point estimate for the multi-stage DCF method.

491. Regarding the evidence submitted on stock market return expectations of finance professionals, in Section 8.5 the Commission maintained its view from previous GCOC decisions that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities, while keeping in mind the purpose and limitations of such estimates.

492. Notwithstanding that the market return expectations of finance professionals may be of some informational value in the determination of a fair ROE for regulated utilities, in this proceeding the evidence received was of little assistance to the Commission for the reasons described in Section 8.5.

493. In Section 8.7, the Commission stated that it will not take any guidance from the evidence presented about approved utility ROEs in other Canadian and U.S. jurisdictions, because the objective of the GCOC is to consider the market expectation for the affected utilities in Alberta and not what other regulators are allowing. With respect to the relationship between capital structure and ROE, and techniques to account for financial risk by adjustment for leverage, the Commission indicated that it had not been persuaded to depart from its findings in the 2016 GCOC decision that it would not employ any of the suggested models in its determination of the deemed equity ratios or the approved ROE except to illustrate that a relationship exists. In the same section, the Commission stated that it has not given any weight to P/B ratio evidence in this proceeding.

494. In this proceeding, the Commission was presented with evidence that utility credit spreads have narrowed since the 2016 GCOC proceeding. In Section 6, the Commission stated that it continues to be of the view that credit spreads are an objective measure, based on observable market data, which help to inform the Commission about utility bond investors' risk perceptions, and by implication, to some extent, the expectations of utility equity investors. While evidence was put forward by Mr. Hevert that a decline in credit spreads may be of a short-term, temporary nature, and may not be indicative of a change in risk perceptions in the market,[643] the Commission is not persuaded by this evidence, which is contradicted by Mr. Hevert's own claims during the 2016 GCOC proceeding that the increase in credit spreads at that time demonstrated an increase in investors' risk perceptions.[644] The Commission agrees with the following statement by the CCA:

> The CCA does not find it credible that, co-incidental with a rise in credit spreads, Mr. Hevert would find that credit spreads are indicative of a need to increase ROE and when they fall, there is no correlation or that within the space of two years the relationship would be broken. Similarly, correlation is not causation. Simply because there is no correlation does not prove that there is no information value. It would be difficult to argue that market has the same perception of risk when credit spreads of 206 versus 140 – it makes no sense since credit spreads are designed to compensate for risk. Finally, while there may be no linkage in the short term, that does not prove anything for the long term – which is what this proceeding is about. For these reasons and given the previous findings of the Commission that credit spreads are informative as to risk, the conclusion of AEF [AltaLink EPCOR FortisAlberta] should be accorded no weight.[645]

495. In Section 6, the Commission found that the global economic and Canadian capital market conditions have improved since the 2016 GCOC proceeding, and are far removed from the 2008-2009 financial crisis. In particular, the Commission observed that there has been 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, the Commission finds that the upward pressure associated with certain of these factors is largely offset by the downward pressure associated with others. On balance, these factors indicate the approved ROE for 2018 should be at or near that set in the 2016 GCOC decision.

643 Exhibit 22570-X0741, PDF pages 14-18.
644 Decision 20622-D01-2016, paragraph 64.
645 Exhibit 22570-X0920, PDF page 21.

496. The Commission also found that the expectations of diminishing national GDP growth rates, moderately higher inflation to reach the mid-point of the Bank of Canada's target range, increasing short-term interest rates, a flattening yield curve, but uncertain long-term interest rates and market uncertainty with respect to international trade, result in a similar offset and together indicate that the approved ROE for 2019 and 2020 should be the same or similar to the value set for 2018.

497. The Commission notes that in the 2016 GCOC decision it awarded an ROE of 8.3 per cent for 2016, and an ROE of 8.5 per cent for 2017. In its correspondence initiating this proceeding, the Commission detailed that this proceeding would consider, amongst other things, whether a change in the approved ROE established in the 2016 GCOC decision is warranted.

498. In the Commission's view, if there has been some upward pressure on ROE since the 2016 GCOC proceeding, part of that pressure has already been accounted for in the 20 bps increase in ROE awarded in 2017. No party focused on the changes since 2016 and no party explained why this increase is either still warranted or is insufficient on a going-forward basis.

499. The 20 bps increase awarded in 2017 was premised on the Commission finding that economic conditions were generally expected to improve in 2017, including an expected increase in interest rates and utility bond yields. The expected increase in 30-year GOC bond yields forecast by the witnesses in this proceeding would arguably signal an increase in approved ROE for 2018 to 2020. However, in the Commission's view, the concomitant expected increase in ROE has been mitigated at least somewhat by the tightening of credit spreads. This has resulted in utility bonds being effectively unchanged since the 2016 GCOC proceeding, contrary to what the Commission considered would occur in Decision 20622-D01-2016. Although the Commission cannot assume that changes in utility equity investors' required returns will align exactly with changes in utility bond investors' expected return, and given that the approved ROE has been increased by 20 bps in that same period, the Commission finds that any additional ROE required by utility investors is largely accounted for in the 2017 adjustment approved in the 2016 GCOC decision.

500. On balance, the Commission is not persuaded by the evidence on the record that a departure from the current approved ROE of 8.50 per cent is warranted. Consequently, the Commission approves 8.50 per cent as the ROE for the affected utilities for 2018, 2019 and 2020.

### 8.9 Returning to a formula-based approach to establishing ROE

501. References were made in this proceeding to the formula-based approach to setting ROE, previously employed by the Commission and its predecessor. For example, in response to a question from Commission counsel with respect to the Consensus economic outlook, Mr. Coyne stated: "… just as this Commission has done in the past when it used a formula, to look to an outside indicator that's readily available, it's transparent. It takes the Commission out of the role of having to guess what the forward path of interest rates is going to be, which is a tough proposition."[646]

[646] Transcript, Volume 5, page 934

502. A standardized approach to the establishment of a single generic ROE to be applied uniformly to all utilities and adjusted yearly using an annual adjustment formula, was approved in Decision 2004-052. In Decision 2009-216, the Commission noted as follows:

> Administrative efficiency in dealing with cost of capital evidence in rate proceedings was clearly an impetus for the Board and parties to consider a generic ROE formula approach and a single proceeding for setting capital structure for all utilities. The Commission considers that the proliferation of regulated companies caused by electric and gas deregulation, unbundling, and corporate reorganizations that influenced the Board to adopt a generic approach remains a compelling reason to continue with that approach.[647]

503. While the Commission has subsequently maintained the approach of having a single proceeding for setting a generic ROE and capital structure for all utilities, it discontinued the annual adjustment/generic ROE formula approach in the 2009 GCOC decision. In departing from the annual adjustment/generic ROE formula approach, the Commission accepted that "during the current financial crisis, the traditional relationship between the risk-free rate (measured as a yield on long Canada bonds) and the required market return on equities has not continued."[648] The Commission also stated that it recognized "there remains a considerable amount of uncertainty in the financial markets and the Commission is concerned that awarding a generic ROE that does not take these uncertainties into account would be unreasonable."[649]

504. The Commission understands that a formula-based approach continues to be employed by certain other regulators. The Commission remains of the view that administrative efficiency is an impetus for consideration of a generic ROE formula approach. The Commission also considers that some of the issues and concerns articulated in this, and previous GCOC decisions, in relation to the approaches to estimating ROE and the varied inputs and results, may be remedied by adopting a formula-based approach in a future proceeding.

505. Based on the evidence regarding market conditions in this proceeding, as summarized in Section 6, the Commission considers that returning to an annual adjustment/generic formula approach to ROE may be reasonable. Specifically, it would appear, based on the evidence in this proceeding, that the reasons justifying a departure from the annual adjustment formula in 2009 may no longer be a concern.

506. The Commission intends to explore the possibility of returning to a formula-based approach to cost of capital matters. The Commission will be initiating a proceeding to explore available options in this regard and will provide notice to that effect to all parties registered in this proceeding in due course.

# 9 Capital structure matters

## 9.1 Overview

507. To satisfy the fair return standard, the Commission is required to determine deemed equity ratios (also referred to as capital structure) for each of the affected utilities. In this

[647] Decision 2009-216, paragraph 220.
[648] Decision 2009-216, paragraph 324.
[649] Decision 2009-216, paragraph 330.

decision, the Commission has established an approved ROE of 8.5 per cent for 2018 through 2020 for all of the affected utilities on a final basis.

508. For the 2018-2020 period, the Commission will maintain its previous approach of setting a uniform approved ROE, and then adjusting for any differences in risk among each of the affected utilities by adjusting the deemed equity ratios. The Commission will make adjustments, if required, to recognize changes in relative risk for each affected utility from the approved deemed equity ratios established in the 2016 GCOC decision.

509. This section of the decision determines the approved deemed percentage of rate base (net of no-cost capital) supported by common equity. The section is organized as follows. Section 9.2, identifies the deemed equity ratios requested by the affected utilities. The Commission's consideration of the factors relevant to the determination of an approved deemed equity ratio for each affected utility begins in Section 9.3 with a review of the evidence in relation to changes in business risk that impact all the affected utilities. In that section, the Commission also compares business risk and deemed equity ratios between the affected utilities and utilities in other jurisdictions. Mr. Hevert's submissions on industry financing practices are addressed in Section 9.4, and the submissions from FortisAlberta on capital attraction are set out in Section 9.5.

510. Before the Commission addresses credit metrics, in Section 9.6 it examines its approach and assesses the submissions from parties on the importance of targeting deemed equity ratios that will permit the affected utilities to maintain A-range credit ratings. The evidence in respect of the credit metrics required by a typical pure-play regulated utility in Canada in order to maintain an A-range credit rating is examined in Section 9.7. In Section 9.8 and Section 9.9, the Commission addresses whether there is a need for different deemed equity ratios for each of the transmission, distribution and the non-taxable utilities. The Commission also evaluates the credit metrics of the affected 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. The Commission addresses the submissions of ENMAX regarding its deemed equity ratio in Section 9.10. The Commission's approved deemed equity ratios for 2018 to 2020 for each of the affected utilities, with the exception of AltaGas, are included in Section 9.11. The approved deemed equity ratio for AltaGas is included in Section 10.

## 9.2 Deemed equity ratios requested

511. Mr. Buttke submitted that investors will look at the results of the 2018 GCOC decision to help form their views of regulatory risk, and to discern trends.[650] He stated that the reductions in the deemed equity ratios made in the 2016 GCOC decision implied that the Commission considered the risk of operating a utility in Alberta was decreasing. However, the market's belief was that the risk was increasing, based on the utility asset disposition (UAD) decision[651] and the transition to PBR.[652]

[650] Exhibit 22570-X0179, A7.
[651] Decision 2013-417: Utility Asset Disposition, Proceeding 20, Application 1566373-1, November 26, 2013.
[652] Exhibit 22570-X0179, A9.

512. Dr. Villadsen[653] commented that in the 2016 GCOC decision, the Commission's focus seemed to be on establishing a deemed equity ratio that would satisfy the bare minimum credit quality standards necessary to obtain an A-range credit rating. Mr. Coyne stated that the Commission appeared to have shifted away from its prior rationale for setting deemed equity ratios on the basis of long-run business and financial risk.[654] Mr. Hevert submitted that the use of pro forma credit metrics as the basis of setting the deemed equity ratios is "concerning."[655]

513. Dr. Villadsen and Mr. Coyne suggested that the credit metric analysis undertaken by the Commission in the 2016 GCOC decision received more weight than (1) the Commission's finding that there was a general increase in generic business risk because of the UAD decision; (2) the Commission's finding that there continued to be differences in business risk as between distribution and transmission utilities; and (3) the Commission's acknowledgement that there is a disadvantage for non-taxable utilities in terms of cash flow and financial flexibility.[656]

514. Dr. Villadsen stated that a singular focus on credit metrics is not sufficient to ensure that a utility can (1) attract equity capital; (2) offer a return equal to that of an alternative investment of comparable risk; and (3) provide a cushion should economic or market conditions move in a negative direction.[657]

515. Dr. Villadsen indicated that her deemed equity ratio recommendations are based on her review of commonly approved equity ratios for regulated utilities and credit metric benchmarks, as well as a review and analysis of credit rating agencies' commentaries on capital structures. Dr. Villadsen recommended a 300 bps increase to the deemed equity ratios for AltaGas and the ATCO Utilities. She stated that the resulting 40 per cent deemed equity ratio for the ATCO Utilities is consistent with other regulated utilities in Canada.[658]

516. AltaLink[659] and EPCOR[660] suggested that while a consideration of credit metrics is important, it is only one factor to be considered in determining a fair return, because credit metrics do not properly account for relevant business risk, financial risks and uncertainties. They submitted that quantitative and qualitative business risk factors must be taken into account, similar to how credit rating agencies take both into account when determining credit ratings.[661]

517. FortisAlberta stated that the Commission's exercise of judgment in determining capital structure should be expanded to address other important factors relating to the role that deemed equity ratios play in overall capital attraction, including the importance of ensuring that equity investors remain willing to support the utility's operations.[662]

518. Mr. Hevert explained that his recommended deemed equity ratio focuses on industry financing practices and ongoing business risks, and considers the Commission's practice of

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[653] Exhibit 22570-X0193.01, A75.
[654] Exhibit 22570-X0131, PDF page 82.
[655] Exhibit 22570-X0153.01, PDF page 111.
[656] Exhibit 22570-X0193.01, A78. Exhibit 22570-0131, PDF page 97.
[657] Exhibit 22570-X0193.01, A75 and A79.
[658] Exhibit 22570-X0193.01, A5.
[659] Exhibit 22570-X0141, paragraphs 27 and 32.
[660] Exhibit 22570-X0195, paragraph 59.
[661] Exhibit 22570-X0141, paragraph 44. Exhibit 22570-X0195, paragraphs 59 and 61.
[662] Exhibit 22570-X0228, paragraphs 14-15.

referring to certain credit metrics.[663] After considering industry financing practices, the historical variability in the parameters underlying the pro forma credit metric calculations used by the Commission in the 2016 GCOC decision, the breadth of data considered by credit rating agencies in arriving at credit ratings, and the relationship between financial leverage and the cost of equity, Mr. Hevert recommended a deemed equity ratio of 40 per cent for AltaLink, EPCOR and FortisAlberta for 2018, 2019 and 2020.[664]

519. Mr. Coyne considered the differences in business risk as between the affected utilities and the utilities in his U.S. electric proxy group, in combination with financial risks, in recommending a deemed equity ratio of 40 per cent for the taxable Alberta electric transmission and distribution utilities. He recommended that the Commission restore the 200 bps adder for the non-taxable utilities in Alberta to compensate for their reduced cash flows and weaker credit metrics. Consequently, his recommended deemed equity ratio for ENMAX is 42 per cent.[665]

520. Calgary argued that circumstances have not changed enough for the Commission to change either the ROE or deemed equity ratios approved in the 2016 GCOC decision. However, Calgary submitted that if the Commission determines that changes should be made, the deemed equity ratio for ATCO Gas should be reduced to 35 per cent, as Mr. Johnson concluded that its business risk is at the low end for natural gas and electricity distribution companies in Canada.[666]

521. Mr. Madsen considered that the Commission's past practice of using credit metrics to assess the deemed equity ratios remains appropriate, and ensures that the approved deemed equity ratios support the ability of the affected utilities to continue to operate in a safe, reliable and economic manner.[667] Mr. Madsen indicated that the primary focus of his recommendations on deemed equity ratios was a consideration of credit metrics and matters relevant to those credit metrics.[668] Mr. Madsen performed an assessment of each utility to arrive at his recommended deemed equity ratio for that utility.[669] His assessment included a review of the deemed equity ratio he calculated for each utility to achieve an A-range credit rating, and a consideration of any utility specific risks. Mr. Madsen's recommended deemed equity ratios are set out in Table 7 below.

522. Dr. Cleary commented that the Alberta utilities possess low risk, as demonstrated by their low earnings volatility, their ability to generate high operating profit margins, and their opportunity for growth in operating earnings. Based on these considerations, combined with his positive economic and capital market outlook, Dr. Cleary recommended no change in the deemed equity ratios. Dr. Cleary instead emphasized the impetus for a reduction in the approved ROE. He submitted that his recommendations are supported by the credit metric analysis provided by Mr. Bell.[670]

523. Mr. Bell recommended a deemed equity ratio of 37 per cent, which he submitted is well within the credit metric guidelines established by S&P and DBRS Limited (DBRS) to maintain

663 Exhibit 22570-X0153.01, PDF page 7.
664 Exhibit 22570-X0153.01, PDF page 11.
665 Exhibit 22570-X0131, PDF pages 9, 87-88, 101.
666 Exhibit 22570-X0903, PDF pages 4-5. Exhibit 22570-X0611.02, A4.
667 Exhibit 22570-X0557, paragraph 144.
668 Exhibit 22570-X0557, paragraph 118.
669 Exhibit 22570-X0557, paragraph 265.
670 Exhibit 22570-X0562.01, PDF page 6.

an A-range credit rating. He did not object to the continuation of a 400 bps increase in deemed equity ratio for AltaGas.[671]

524. The currently approved deemed equity ratios, and the recommended figures for 2018, 2019 and 2020, are set out in the following table.

**Table 7. Currently approved deemed equity ratios and the deemed equity ratios recommended for 2018, 2019 and 2020**

| | Last approved [672] | Recommended by AltaGas and the ATCO Utilities[673] Dr. Villadsen | Recommended by AltaLink/ EPCOR/ FortisAlberta[674] Mr. Hevert | Recommended by ENMAX[675] Mr. Coyne | Recommended by Calgary[676] Mr. Johnson | Recommended by the CCA[677] Mr. Madsen | Recommended by the UCA[678] Dr. Cleary |
|---|---|---|---|---|---|---|---|
| | (%) | | | | | | |
| **Electricity and natural gas transmission** | | | | | | | |
| AltaLink | 37 | | 40 | | | 35 | 37 |
| ATCO Electric Transmission | 37 | 40 | | | | 35 | 37 |
| ATCO Pipelines | 37 | 40 | | | | 36 | 37 |
| ENMAX Transmission | 36 | | | 42 | | 36 | 36 |
| EPCOR Transmission | 37 | | 40 | | | 36 | 37 |
| Lethbridge | 37 | | | | | | |
| Red Deer | 37 | | | | | | |
| TransAlta | 37 | | | | | | |
| **Electricity and natural gas distribution** | | | | | | | |
| AltaGas | 41 | 44 | | | | 41 | 41 |
| ATCO Electric Distribution | 37 | 40 | | | | 36 | 37 |
| ATCO Gas | 37 | 40 | | | 35 | 35 | 37 |
| ENMAX Distribution | 36 | | | 42 | | 36 | 36 |
| EPCOR Distribution | 37 | | 40 | | | 36 | 37 |
| FortisAlberta | 37 | | 40 | | | 35 | 37 |

671 Exhibit 22570-X0559, A18.
672 Decision 20622-D01-2016, Table 26, paragraph 622. For ATCO Electric Transmission, the deemed equity ratio was approved in Decision 22121-D01-2016: ATCO Electric Ltd. Transmission Operations, Application for Finalization of Return on Equity and Deemed Equity Ratio for 2016-2017, Proceeding 22121, December 16, 2016. For ENMAX Transmission and ENMAX Distribution, the deemed equity ratio was approved in Decision 22211-D01-2017: ENMAX Power Corporation, Application for Finalization of Deemed Equity Ratio for 2016-2017, Proceeding 22211, July 27, 2017.
673 Exhibit 22570-X0193.01, Figure 33.
674 Exhibit 22570-X0153.01, PDF page 123.
675 Exhibit 22570-X0131, PDF page 10.
676 Exhibit 22570-X0611.02, PDF page 2.
677 Exhibit 22570-X0557, PDF page 74.
678 Exhibit 22570-X0562.01, PDF page 96. Transcript, Volume 10, pages 2098-2099.

### 9.3 Generic business risk analysis

525. In this section of the decision, the Commission considers the evidence on business risk factors impacting all the affected utilities, or a particular segment of the affected utilities, that may require the Commission to adjust the deemed equity ratios approved in the 2016 GCOC decision.

526. As previously mentioned, Mr. Hevert, Mr. Coyne, Mr. Johnson and Dr. Cleary each indicated that business risk was either one of the factors, or the primary factor, underlying their recommended deemed equity ratios. In addition, based primarily on the business risk assessment undertaken by Dr. Carpenter, Dr. Villadsen argued for using the deemed equity ratios of U.S. utilities as comparators.[679]

527. Dr. Carpenter defined business risk as "the underlying risks inherent in a particular company's operations." He added that while business risk is "a somewhat subjective concept, and there is more than one way of structuring an analysis of business risk, an approach that is commonly taken is to consider five elements of business risk: supply risk, demand (or market) risk, competitive risk, operating risk and regulatory risk."[680] Mr. Hevert agreed that these five elements of business risk all have a direct bearing on earnings levels and volatility.[681]

528. Dr. Carpenter assessed the business risk of AltaGas and the ATCO Utilities relative to their business risk in the past, and relative to the business risks of utilities in other jurisdictions. He particularly focused on utilities owned by the companies that Dr. Villadsen used as proxy groups in her evidence. Dr. Carpenter's analysis also focused on the natural gas and electricity distribution functions, which he noted the Commission had used as a benchmark in prior proceedings.[682]

529. Mr. Coyne undertook a proxy group risk analysis in order to help determine his recommended equity ratios. Noting the limited number of companies in his Canadian utility proxy group, Mr. Coyne looked to a U.S. sample of low-risk electric utilities. Mr. Coyne indicated that he examined the business and financial risks of his U.S. electric proxy group, relative to those of a typical Alberta electric transmission and electric distribution utility.[683]

530. Mr. Johnson assessed the business risk of ATCO Gas relative to other natural gas distributors in Canada and the U.S.

531. Mr. Hevert identified uncertainties associated with regulation that are faced by AltaLink, EPCOR and FortisAlberta.

532. Dr. Cleary primarily used quantitative analysis to assess the business risks of the utilities in Alberta on an overall basis, as well as in comparison to U.S. utilities.

533. The Commission will first examine the overall assessment of business risk of the utilities in Alberta offered by Dr. Cleary. Next, the Commission will address changes in business risks

679 Exhibit 22570-X0193.01, A17.
680 Exhibit 22570-X0186, A10.
681 Exhibit 22570-X0153.01, PDF page 21.
682 Exhibit 22570-X0186, A4.
683 Exhibit 22570-X0131, PDF page 86.

since the 2016 GCOC decision that were identified by Dr. Carpenter, Mr. Coyne, Mr. Hevert and the affected utilities. Subsequent to that, the Commission will address the business risk comparisons between the affected utilities and other jurisdictions submitted by Dr. Carpenter, Mr. Coyne, Mr. Johnson and Dr. Cleary.

### 9.3.1 Overall assessment of business risk

534. Dr. Cleary agreed with the favourable assessment of business risk for the affected utilities included in credit rating reports issued by DBRS and S&P.[684] Dr. Cleary stated that regulated Alberta operating utilities possess low business risk and enjoy solid regulatory support.[685] Dr. Cleary undertook some empirical analysis that purported to support his conclusion that the affected utilities operate in a low-risk environment that enables them to earn above their approved ROEs with very little volatility in income.[686]

535. Part of Dr. Cleary's empirical analysis examined the ability of the affected utilities to earn their approved ROE on a consistent basis from 2005 to 2016, which he described as a bottomline measure of the total risks faced by the utilities.[687] The yearly figures illustrated that the affected utilities earned average and median ROEs above the approved ROE in all years except 2005, when the average ROE was 0.18 per cent below the approved ROE. Dr. Cleary submitted this can be considered the strongest indication that the affected utilities possess low overall risk.[688]

**Commission findings**

536. The Commission accepts that the favourable financial performance and low volatility of earnings illustrated by Dr. Cleary is support for the conclusion that the affected utilities have generally low business risk.

### 9.3.2 Changes in business risk since the 2016 GCOC decision

537. The affected utilities and their witnesses focussed on issues related to regulatory risk. The main issues identified were (1) the 2018-2022 PBR term; (2) the Commission's UAD decision and the related issue of asset utilization; (3) the increase in customer contributions; (4) regulatory lag; and (5) clean energy initiatives. These issues will be addressed in the following sections.

#### 9.3.2.1 2018-2022 PBR term

538. Dr. Carpenter, Mr. Coyne and EPCOR submitted that changes associated with the 2018-2022 PBR term will increase risk, primarily with respect to the distribution utilities' ability to recover operating and capital costs.[689] ENMAX noted the Commission's adoption of the K-bar methodology, and submitted that the Commission's willingness to reopen aspects of the PBR framework at the last minute, and in isolation, is a troubling development that materially increases the risks and uncertainty that its distribution utility faces.[690]

684 Exhibit 22570-X0562.01, PDF pages 74-75.
685 Exhibit 22570-X0562.01, PDF page 75.
686 Exhibit 22570-X0562.01, PDF page 77.
687 Exhibit 22570-0562.01, PDF page 79.
688 Exhibit 22570-0562.01, PDF pages 79-81.
689 Exhibit 22570-X0186, A41. Exhibit 22570-X0131, PDF page 78. Exhibit 22570-X0733, A22.
690 Exhibit 22570-X0773, paragraphs 17-21.

539. With respect to the increased uncertainty of operating cost recovery, Dr. Carpenter submitted that the Commission's approach to rebasing for the 2018-2022 PBR term does not align revenues with costs at the start of the term; as a result, business risk is increased.[691] Dr. Carpenter stated it is unusual that rebasing is not cost-of-service based,[692] and he commented that this is a fundamentally different approach for rebasing.[693] Mr. Coyne agreed that the 2018-2022 PBR term plan is a significant departure from the previous PBR plan, and provides additional risk on several fronts.[694] Dr. Carpenter submitted that the Commission's decision to reject all of the expense anomalies proposed by the distribution utilities will create a shortfall for the utilities and increases business risk.[695] He proposed that rejection of the anomalies requested by AltaGas and the ATCO Utilities amount to a reduction of 50 bps in annual ROE.[696]

540. Dr. Carpenter submitted that the Commission's evolving approach to the calculation of K-bar, including its decision to apply a new K-bar methodology for the 2018-2022 PBR plan, is a source of increased risk.[697] He submitted this new methodology creates a disconnect between the need for and the availability of supplemental capital funding, which creates capital recovery risk.[698] EPCOR submitted that the annual updating of the K-bar will reduce the certainty and predictability of the capital funding that will be provided.[699] Dr. Carpenter estimated the impact of applying this annual K-bar update for ATCO Electric Distribution and ATCO Gas to be equivalent to an annual reduction in authorized ROE of over 100 bps.[700] EPCOR indicated that annual updates to base K-bar alone would reduce its expected ROE by nearly 200 bps.[701]

541. EPCOR suggested there is substantial uncertainty as to whether its distribution function will have access to the supplemental funding it requires to address the AESO's proposed 2018 tariff application, which will require more transmission connection projects costs to be funded by customer contributions.[702] Mr. Coyne referred to the provincial government's target of 30 per cent renewable generation by 2030, which the government hopes to accomplish in part by the widespread deployment of distributed generation. Mr. Coyne stated that costs required for the distribution utilities to develop infrastructure capable of integrating increased volumes of distributed generation are currently not provided for under PBR.[703]

542. The UCA submitted that the use of a K-bar mechanism under the 2018-2022 PBR term improves the incentive properties of the PBR plan. It stated that any changes made to the K-bar mechanism in the 2018-2022 PBR term rebasing decision do not impact the underlying PBR plan and it suggested that the annual updating of the inputs into the K-bar mechanism could result in increased K-bar revenues.[704] The UCA stated that the Commission addressed concerns about lack

691 Exhibit 22570-X0751, A64.
692 Exhibit 22570-X0751, A61.
693 Exhibit 22570-X0186, A41.
694 Exhibit 22570-X0775, PDF page 58.
695 Exhibit 22570-X0751, A59-A60.
696 Exhibit 22570-X0751, A63.
697 Exhibit 22570-X0751, A51.
698 Exhibit 22570-X0751, A52.
699 Exhibit 22570-X0733, A11.
700 Exhibit 22570-X0751, A66, A69.
701 Exhibit 22570-X0733, A11.
702 Exhibit 22570-X0195, paragraphs 23, 25, 27-28.
703 Exhibit 22570-X0131, PDF page 76.
704 Exhibit 22570-X0767.01, paragraph 298.

of sufficient funding under K-bar, as part of Decision 22394-D01-2018. It noted that the Commission was not persuaded by the arguments of the utilities in that proceeding about having a lack of sufficient funding.[705]

543. Mr. Bell disagreed with the concerns about the 2018-2022 PBR term raised by the utilities and their experts. He submitted that the financial performance of the distribution utilities under the first PBR term improved, when compared to the utilities that remained under cost of service. Mr. Bell indicated that the actual ROEs for the distribution utilities under the first term of the PBR plan improved, as compared to their actual ROEs prior to PBR. He submitted this improvement indicates that risk declined in the first PBR term. Mr. Bell noted that while the approved ROEs have declined from the time prior to the first PBR term, the actual ROEs achieved over the first PBR term have increased.[706]

544. Mr. Johnson stated that being under a PBR regime does not increase the regulatory risk of ATCO Gas. He referred to the actual ROEs earned by ATCO Gas in 2013 (11.86 per cent), 2014 (10.95 per cent), 2015 (11.10 per cent) and 2016 (12.93 per cent), and noted that, in each year, the actual ROEs were in excess of the approved ROEs, which were 8.30 per cent.[707]

545. Dr. Carpenter submitted that Mr. Bell's examination of historically achieved ROEs is unlikely to be meaningful because it compares actual ROEs averaged over a different number of years. Based on his own calculations using data averaged over time periods of four years, Dr. Carpenter reported that the difference between the actual ROEs in the most recent four-year PBR time period and the prior four-year cost-of-service period are nearly the same as the difference in the actual ROEs between the 2005 to 2008 and 2009 to 2012 cost-of-service periods.[708] EPCOR commented that Mr. Bell's use of four data points lacks statistical rigour.[709]

546. EPCOR commented that increased returns under PBR are not surprising because of the incentives that exist under PBR, and they are not indicative of decreased risk. EPCOR submitted it will have more difficulty identifying and implementing efficiency improvements during the 2018 to 2022 PBR term and because of this, it will face greater uncertainty and risk under the 2018 to 2022 PBR term than it did under the first PBR term.[710]

547. Mr. Madsen stated that the distribution utilities will have a reasonable opportunity and incentives to recover their prudently incurred costs over the 2018 to 2022 PBR term, which is consistent with the Commission's findings in Decision 20414-D01-2016 (Errata).[711]

548. The UCA submitted that the intent of PBR was not to increase risk, but rather to provide appropriate incentives for regulated utilities to improve efficiencies and share any resulting cost savings with customers. It contended that this intent will be significantly undermined if the utilities are able to successfully argue that the presence of such incentives increases their risk and

705 Exhibit 22570-X0913, paragraph 164.
706 Exhibit 22570-X0559, A14.
707 Exhibit 22570-X0611.02, A7.
708 Exhibit 22570-X0751, A46.
709 Exhibit 22570-X0733, A7.
710 Exhibit 22570-X0733, A6.
711 Decision 20414-D01-2016 (Errata): Errata to Decision 20414-D01-2016, 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, February 6, 2017. Exhibit 22570-X0557, paragraph 127.

therefore requires additional compensation through the GCOC. The UCA stressed that in the 2013 GCOC decision, the Commission was not persuaded that the transition to PBR had resulted in a change in the risk profile that warranted any adjustments to the approved ROE and deemed equity ratios.[712]

**Commission findings**

549. As part of the 2013 GCOC decision, the Commission considered whether PBR increased the business risk of the distribution utilities. In that decision, the Commission denied a request for an increase of 75 bps in the deemed equity ratio because of the implementation of PBR.[713] The Commission noted that the utilities had the opportunity to apply for Y, Z and K factor adjustments and, since the implementation of PBR in 2013, all but one of the distribution utilities achieved actual ROEs in 2013 that were in excess of the interim approved ROE for that year. The Commission also noted that the risks asserted by the distribution utilities had not manifested themselves through credit rating downgrades.[714]

550. In this proceeding, the evidence likewise fails to support that any changes associated with the 2018 to 2022 PBR term will increase risk to the distribution utilities, including risk respecting the ability to recover operating and capital costs. As a preliminary observation, the Commission notes that while the 2018 to 2022 PBR term includes adoption of new rebasing and capital funding mechanisms, the underlying structure and intent of PBR is largely unchanged. The Commission has received no persuasive evidence of any negative market response to the PBR framework since its implementation in 2013. The Commission agrees with the UCA's submission that the intent of implementing PBR was not to increase risk for the distribution utilities, but to provide incentives for the utilities to improve efficiencies, and to benefit financially from these improvements. The evidence supports that intent has generally been realized. While EPCOR submitted it will have more difficulty identifying and implementing efficiency improvements during the 2018 to 2022 PBR term, this does not rule out the possibility that efficiencies will continue to be achieved. In addition, the 2018 to 2022 PBR plan retains the opportunity to apply for Y, Z and K factor adjustments, and includes off-ramp and reopener provisions to safeguard the financial integrity of the affected utilities.

551. As for the more specific risks asserted by Mr. Coyne, Dr. Carpenter and EPCOR with respect to the distribution utilities' ability to recover operating and capital costs due to changes associated with the 2018-2022 PBR term, the Commission has, in Decision 20414-D01-2016 (Errata), stated it "is satisfied that the distribution utilities will have a reasonable opportunity to earn their allowed rates of return over the next generation PBR plans."[715] The Commission added to this finding in Decision 22394-D01-2018 as follows:

> 425. The Commission is satisfied that the distribution utilities will have a reasonable opportunity to earn their allowed rates of return over the period covered by the 2018-2022 PBR plans. The Commission has reached this conclusion having had regard to the evidence filed in Proceeding 20414, the additional evidence filed in this compliance proceeding and the elements of the PBR plans approved in Decision 20414-D01-2016

712 Exhibit 22570-X0913, paragraphs 156-157.
713 Decision 2191-D01-2015, paragraph 380.
714 Decision 2191-D01-2015, paragraphs 377-378.
715 Decision 20414-D01-2016 (Errata), paragraph 288.

(Errata) as refined in this decision, and having applied its experience, expertise and judgement in carrying out its mandate to set just and reasonable rates.[716]

552. No persuasive evidence has been offered to support a conclusion contrary to those quoted above from Decision 20414-D01-2016 (Errata) and Decision 22394-D01-2018.

553. Based on the foregoing, the Commission finds that there is no increase in business risk as a result of the 2018 to 2022 PBR plan.

#### 9.3.2.2 The Commission's UAD decision and the related issue of asset utilization

554. In the 2016 GCOC decision, the Commission addressed the issue of incremental business risk to utility investors stemming from developments with respect to the UAD decision that occurred between the 2013 GCOC proceeding and the 2016 GCOC proceeding.[717] In the current proceeding, Mr. Buttke indicated that the market took some comfort from the Commission's acknowledgement in the 2016 GCOC decision that the UAD decision directionally increased investor risk.[718]

555. AltaLink[719] and EPCOR[720] submitted that no new developments have occurred since the 2016 GCOC decision that would reduce their risk associated with the UAD decision. Dr. Carpenter,[721] EPCOR,[722] FortisAlberta[723] and AltaLink[724] pointed out that since the 2016 GCOC decision, new developments have occurred with respect to the UAD decision that increase the business risk of the affected utilities.

556. Dr. Carpenter noted several changes since the 2016 GCOC decision. He noted that the Government of Alberta initiated a consultation with stakeholders regarding possible legislation to address outstanding concerns in relation to UAD-related decisions. He submitted this underscores the significance of investor uncertainty associated with the Commission's UAD policy.[725] EPCOR and FortisAlberta agreed that this consultation has increased the level of uncertainty regarding their ability to recover capital.[726]

557. Dr. Carpenter also noted that the Commission expressed its intent to initiate a process to consider the issue of transmission asset utilization, which was raised by the CCA as part of deferral account proceedings for AltaLink and ATCO Electric Transmission.[727] AltaLink stated that any suggestion that a denial of prudently incurred capital costs could be based on asset utilization is a significant new uncertainty that will be closely monitored by capital market

716 Decision 22394-D01-2018, paragraph 425.
717 Decision 20622-D01-2016, Section 7.4.1.
718 Exhibit 22570-X0179, A13.
719 Exhibit 22570-X0141, paragraph 14.
720 Exhibit 22570-X0195, paragraph 21.
721 Exhibit 22570-X0186, A61. Exhibit 22570-X0751, A66, A69, A76.
722 Exhibit 22570-X0195, paragraph 21.
723 Exhibit 22570-X0228, paragraph 28.
724 Exhibit 22570-X0141, paragraph 13.
725 Exhibit 22570-X0186, A61.
726 Exhibit 22570-X0195, paragraph 21. Exhibit 22570-X0228, paragraph 28.
727 Exhibit 22570-X0186, A5.

participants. AltaLink indicated that credit rating agencies have already taken notice of this issue.[728]

558. Dr. Carpenter indicated his understanding that the Commission's asset utilization proceeding will raise the prospect that capital cost recovery might be denied for certain prudently constructed new electric transmission capital assets. He submitted this represents a new source of capital recovery risk for the electric transmission utilities.[729] Dr. Carpenter stated he is not aware of any other regulatory jurisdictions that are considering whether cost recovery for prudently incurred capital assets should be denied.

559. Dr. Carpenter submitted that the future uncertainty about potential disallowances is what causes an increase in business risk. He noted that in its decision on the 2018 to 2022 PBR term rebasing,[730] which was issued since the 2016 GCOC decision, the Commission denied EPCOR's request to recover the undepreciated capital costs of its conventional meters.[731] Dr. Carpenter submitted that while the costs at stake with respect to EPCOR's conventional meters were relatively small, the decision was important because it reaffirmed the Commission's application of the UAD principles, and emphasized the Commission's belief that it lacks any discretion in their application.[732]

560. EPCOR stated that the asset utilization proceeding has increased the level of uncertainty regarding its ability to recover invested capital.[733] AltaLink suggested that where this issue will end up is unclear, but it is clear that it increases the uncertainty that must be assessed by any informed investor in an Alberta utility.[734]

561. The CCA noted that AltaLink was acquired by Berkshire Hathaway Energy after the issuance of the UAD decision. It submitted this is clear evidence that sophisticated shareholders are aware of, and accept, the UAD risks in Alberta.[735]

562. Mr. Madsen commented that the Commission has already compensated the affected utilities for the UAD asset risk.[736] He also contended that any risks associated with UAD are fully or partially offset by the upside benefits obtained when assets are sold.[737]

563. Mr. Bell suggested that the return associated with UAD risk for a utility should be the gains realized when a utility sells a capital asset, and he stated that the affected utilities have benefitted from removing property from rate base, in the amount of $17.3 million at least, to date.[738]

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728 Exhibit 22570-X0141, paragraphs 9, 11.
729 Exhibit 22570-X0186, A57, A60.
730 Decision 22394-D01-2018.
731 Exhibit 22570-X0751, A74-A75.
732 Exhibit 22570-X0751, A66, A69, A76.
733 Exhibit 22570-X0195, paragraph 21.
734 Exhibit 22570-X0141, paragraph 13.
735 Exhibit 22570-X0920, paragraph 256.
736 Exhibit 22570-X0557, paragraph 177.
737 Exhibit 22570-X0557, paragraph 182.
738 Exhibit 22570-X0559, A9-A10.

564. Mr. Johnson stated that, unlike other Canadian regulators, the Commission has enunciated UAD principles, which confirm that the affected utilities have an equal opportunity to enhance their return by selling capital assets that are no longer required to provide utility service. Mr. Johnson submitted that this additional return offsets the potential for losses. He contended that ATCO Gas has been successful in this regard.[739]

565. Dr. Carpenter contended that the risk of disallowances under UAD is a forward-looking risk and because of this, any past gains earned by the affected utilities cannot reduce the forward-looking risk.[740] EPCOR noted that Mr. Bell's submissions were filed before the release of the Commission's decision on the 2018 to 2022 PBR term rebasing, in which the Commission denied EPCOR's request to recover $9 million related to its conventional meters.[741]

566. AltaLink submitted it is critical to be proactive in managing risk. It contended that it takes many years to recover from a credit rating downgrade when one occurs. AltaLink commented that the Commission has made it clear that it is more beneficial to act to mitigate risk than to wait and take action after a downgrade has occurred.[742]

567. The CCA pointed out that, as described in Decision 20407-D01-2016,[743] EPCOR made a decision to proceed with its advanced metering infrastructure project regardless of the Commission's determinations on the treatment of the remaining net book value of the conventional meters.[744] It stated that the Commission also made a number of findings of fact in Decision 20407-D01-2016, which made it clear that there would be stranded asset costs at the time of the PBR rebasing.[745]

568. The UCA commented that the Commission first addressed EPCOR's meter replacement issue in Decision 3100-D01-2015,[746] which was issued in January 2015. It noted that in Decision 3100-D01-2015, the Commission determined that the book value of the undepreciated meters was to the account of EPCOR's shareholder.[747] The UCA summarized that in Proceeding 22394, EPCOR argued that the law had changed to give the Commission greater flexibility and discretion to depart from the strict application of the principles applied in the Stores Block decision. The UCA indicated that in Decision 22394-D01-2018, the Commission disagreed that such discretion exists and found no basis upon which to alter its previous findings.[748]

569. Mr. Madsen stated that asset utilization is a risk that is related to the UAD decision, and he noted that the Commission's asset utilization proceeding had not been initiated as of January 2018.[749] He submitted that no real cost, or risk of a cost, has materialized to date with regard to

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739 Exhibit 22570-X0611.02, A8.
740 Exhibit 22570-X0751, A82.
741 Exhibit 22570-X0733, A30.
742 Exhibit 22570-X0738, paragraphs 54, 57-58.
743 Decision 20407-D01-2016: EPCOR Distribution & Transmission Inc., 2014 Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20407, February 7, 2016.
744 Decision 20407-D01-2016, paragraph 647.
745 Decision 20407-D01-2016, paragraphs 616-618.
746 Decision 3100-D01-2015: EPCOR Distribution & Transmission Inc., 2013 PBR Capital True-Up and 2014-2015 PBR Capital Tracker Forecast, Proceedings 3216 and 3100, Applications 1610565-1 and 1610362-1, January 25, 2015.
747 Decision 3100-D01-2015, paragraph 691.
748 Exhibit 22570-X0913, paragraph 51.
749 Exhibit 22570-X0557, paragraph 177.

asset utilization.[750] The CCA submitted the asset utilization issue has existed at least since the issuance of the UAD decision, and therefore it is not a new issue.[751]

570. On May 8, 2018, AltaGas and the ATCO Utilities, in the cover letter accompanying their reply argument, noted that Bill 13: *An Act to Secure Alberta's Electricity Future*, had been tabled in the Alberta legislature on April 19, 2018. AltaGas and the ATCO Utilities stated that Bill 13 touched on a number of matters that received attention at the hearing, and noted that legislative action was specifically identified in Dr. Carpenter's evidence regarding UAD. AltaGas and the ATCO Utilities stated that they were reserving their rights to address the impact of any legislative changes on the cost of capital over the 2018 to 2020 period and requested that the Commission confirm that the record would be reopened to address the impact of any legislative changes over the GCOC test period.

**Commission findings**

571. The three factors cited by the affected utilities in support of their submission that their business risk has increased since the 2016 GCOC decision as a result of the UAD decision or the related issue of asset utilization are (1) the Government of Alberta's stakeholder consultation; (2) the Commission's intent to initiate a process to consider transmission asset utilization; and (3) the Commission's decision to deny EPCOR's request to recover the undepreciated capital costs of its conventional meters. The Commission addresses each of these considerations below.

572. The Alberta legislature passed Bill 13 on June 11, 2018. It does not include any provisions relating to the UAD decision, stranded asset cost recovery or asset utilization. Nor has any party requested that the record of this proceeding be reopened to address the impact of these legislative changes, as discussed in the above-mentioned correspondence filed on behalf of AltaGas and the ATCO Utilities on May 8, 2018. Accordingly, the Commission is not persuaded that the outcome of the Government of Alberta's stakeholder consultation on the UAD decision has resulted in any change in business risk for the affected utilities for the 2018 to 2020 period.

573. With respect to the transmission asset utilization issue, the Commission advised parties on June 20, 2017, that it would be "issuing a bulletin shortly to initiate a process to consider the issue."[752] As of the close of the record of this proceeding, no bulletin has been issued and no proceeding has been initiated. The timing and outcome of any transmission asset utilization proceeding that may be subsequently held is unknown at this time and purely speculative.

574. Additionally, issues around transmission asset utilization are connected to the UAD decision, "and how the corporate and property law principles applied by the courts in the Alberta legislative context as referenced in the UAD decision may relate."[753] The Commission considers that the markets and investors have had ample opportunity to become familiar with these principles since the UAD decision was released in November 2013. The UAD decision and subsequent decisions implementing its principles are not new, and the Commission expects that investors already factor this into their decision making. The CCA noted that Berkshire Hathaway Energy acquired AltaLink subsequent to the issue of the UAD decision.

[750] Exhibit 22570-X0557, paragraph 179.
[751] Exhibit 22570-X0920, paragraph 316.
[752] Exhibit 22393-X0150, paragraph 8.
[753] Exhibit 22393-X0150, paragraph 7.

575. For the foregoing reasons, the Commission finds that speculation regarding the potential outcome of any future asset utilization proceeding is not justification for an overall increase in business risk.

576. As to the suggestion that business risk has increased as a result of the Commission's denial of EPCOR distribution's request to recover $9 million related to its conventional meters, the Commission agrees with the CCA and the UCA that this issue was initially addressed in 2015, when the Commission issued Decision 3100-D01-2015. In that decision, the Commission determined that the book value of the undepreciated conventional meters was to the account of EPCOR's shareholder.[754] In Decision 22394-D01-2018, which was issued on February 5, 2018, the Commission found no basis upon which to alter its previous findings of fact with respect to this matter.[755] The Commission finds that the confirmation of previous findings made with respect to UAD in decisions from 2015 and early 2016 are not reflective of an increase in business risk for the affected utilities since the 2016 GCOC proceeding.

577. In conclusion, the Commission is not satisfied that there has been an increase in business risk for the affected utilities since the 2016 GCOC proceeding with regard to the UAD decision or the related issue of asset utilization.

#### 9.3.2.3 Increase in customer contributions

578. AltaLink stated that it has been, and continues to be, exposed to risks and liabilities associated with owning and operating capital assets for which customer contributions have been received, but on which it earns no return. It noted that these customer contributions continue to increase, and there is the potential for these to increase even more because of the AESO's proposal in its 2018 tariff application that will classify more transmission connection project costs to be funded by customer contributions.[756] EPCOR indicated that this potential increase in customer contributions also creates uncertainty for its transmission function.[757]

579. EPCOR stated that its transmission function is responsible for the operating and maintenance (O&M) costs for any capital assets funded by customer contributions, and it faces forecasting risk with respect to these O&M costs. EPCOR contended that forecasting risk is typically compensated by the return component of the revenue requirement, but in the case of customer contributions, it receives no return and thus no compensation for the forecasting risk.[758]

580. Mr. Madsen stated that AltaLink's forecast balance of the gross and net customer contributions as of December 31, 2017 and December 31, 2018, as a percentage of the gross and net property, plant and equipment (PP&E) balances, do not exceed historical actual levels.[759]

581. Mr. Bell commented that the vast majority of the customer contributions received by the electricity transmission utilities are from the electricity distribution utilities. He suggested that if the transmission utilities are correct about their level of risk increasing because of increased

[754] Decision 3100-D01-2015, paragraph 691.
[755] Decision 22394-D01-2018, paragraph 395.
[756] Exhibit 22570-X0141, paragraphs 23-24.
[757] Exhibit 22570-X0195, paragraph 32.
[758] Exhibit 22570-X0195, paragraph 31.
[759] Exhibit 22570-X0557, paragraphs 223-227.

customer contributions, then there should be a corresponding decrease in the risk for the distribution utilities.[760]

582. EPCOR commented that any customer contributions paid from its distribution utility to its transmission utility increases uncertainty and risk to both entities. It explained that the increased uncertainty for the distribution utility arises because the recovery of its carrying costs related to the customer contributions is not guaranteed under the PBR framework.[761]

**Commission findings**

583. AltaLink's forecast customer contribution amounts at the end of 2018 comprise less than 10 per cent of its total PP&E. The forecast percentages for 2018 (9.0 per cent of the gross PP&E and 9.4 per cent of the net PP&E) are within the range of the actual percentages for the years 2013 to 2016, which range from 8.3 per cent to 9.1 per cent of the gross PP&E, and 8.7 per cent to 10.4 per cent of the net PP&E.[762] This evidence does not support AltaLink's submissions regarding increased business risk since the 2016 GCOC proceeding.

584. While both AltaLink and EPCOR referenced the potential for electricity transmission utilities to receive increased customer contributions because of proposals included in the AESO's 2018 tariff application, no decision on the AESO's 2018 tariff application has been issued. The Commission cannot know whether this proposal will be accepted or not, and it will not speculate on the outcome. An AESO proposal not yet addressed is not justification for an increase in business risk.

585. EPCOR submitted that there would be increased business risk for its distribution utility if the AESO's proposal is approved, because of the uncertainty associated with the capital funding mechanism under the 2018 to 2022 PBR plan. The Commission has previously found that the 2018 to 2022 PBR plan does not increase the business risk of the distribution utilities relative to the risk at the time of the 2016 GCOC proceeding.

586. No evidence was presented that would enable the Commission to assess whether the risks in operating assets that were funded in whole or in part by customer contributions are any different than the risks in operating assets for which no customer contributions have been received. No evidence was presented on how customer contributions may help reduce stranded asset risk.

587. Customer contributions are treated as no-cost capital, as are funds collected for FIT. The pre-collection of future returns through CWIP-in-rate base, and the pre-collection of funds through higher salvage rates and excess depreciation rates, can also be considered a form of no-cost capital on regulatory balance sheets.

588. The Commission allowed CWIP-in-rate base and the collection of FIT for AltaLink and ATCO Electric Transmission to assist with cash flow and credit metric support during the large transmission build, but has allowed these utilities to refund those no-cost capital accumulations. ATCO Electric Transmission had requested an increase in net salvage in their last general tariff application (GTA) but was denied. AltaLink had requested an increase in net salvage in their last

760 Exhibit 22570-X0559, A19-A23.
761 Exhibit 22570-X0733, A26.
762 Exhibit 22570-X0464, AML-CCA-2017NOV21-005.

litigated GTA before their negotiated settlement GTA and that was partially approved. In this GCOC proceeding, AltaLink indicated that they are looking at potentially applying for a reduction in net salvage on the same terms as EPCOR.[763]

589. The Commission observes that no-cost capital is an inherent aspect of regulated utilities' balance sheets and requests for increases and decreases to these no-cost capital balances have occurred over the years for many reasons. Cash flow injections have assisted utilities at critical times in their operations and have supported credit metrics. Yet at the same time utilities request increases to their approved ROE because of the increase in business risk of managing these no-cost capital assets.

590. With CWIP-in-rate base removed, and pre-collected FIT amounts as well as pre-collected excess depreciation amounts refunded by AltaLink, in the Commission's view it can be argued that utilities have reduced their business risk through reductions in no-cost capital.

591. For all of the above reasons, the Commission finds that there is no increase in business risk from customer contributions for the affected utilities since the 2016 GCOC proceeding.

#### 9.3.2.4 Regulatory lag

592. Dr. Carpenter stated that approximately $3 billion of capital costs are subject to deferral account proceedings for the electric transmission utilities, and the lag in finalizing these proceedings creates uncertainty.[764] Mr. Buttke commented that regulatory lag generates increased uncertainty with respect to revenues and ROE. He added that this increased uncertainty will cause investors to increase their required rate of return, all else equal, or it will cause them to shift their capital to jurisdictions with less uncertainty.[765]

593. AltaLink stated that it remains subject to regulatory lag. It noted that the 2018 GCOC decision will result in prospective ROEs for all of 2019 and all of 2020, but only for a portion of 2018. It anticipates a decision on its 2014 direct assigned capital deferral account (DACDA) in 2018 at the earliest, and it advised that this decision will not result in final approval if the asset utilization issue is not resolved by that time. AltaLink stated that it has approximately $4 billion of completed capital projects pending prudency reviews through DACDA proceedings.[766]

594. AltaLink commented that regulatory lag is harmful because it creates market uncertainty and increases the risk of adverse credit-rating action. It added that regulatory lag increases the uncertainty and volatility in cash flows, which increases the market perception of risk.[767]

595. Mr. Madsen contended that if the Commission disallows any capital expenditures made by a utility, it would be because the expenditure was deemed to be imprudent. He submitted that any such disallowances should not be considered when the Commission determines a fair return for the utilities.[768]

[763] Transcript, Volume 6, page 1088.
[764] Exhibit 22570-X0131, A5.
[765] Exhibit 22570-X0179, A10.
[766] Exhibit 22570-X0141, paragraphs 15, 17-18.
[767] Exhibit 22570-X0141, paragraphs 19 and 21.
[768] Exhibit 22570-X0557, paragraphs 204-207.

596. AltaLink submitted that it is not seeking compensation for prudency risk. It explained that regulatory lag prevents the timely implementation of ongoing Commission findings and recommendations into its project execution, in order to address any prudency concerns the Commission has identified.[769] AltaLink also argued that increased regulatory lag increases the risk of adverse credit-rating action.

**Commission findings**

597. The Commission agrees with Dr. Carpenter and Mr. Buttke that regulatory lag creates uncertainty. However, this lag has existed for many years and is not new. The 2016 GCOC decision resulted in an approved ROE and deemed equity ratios that were fully prospective for one year. The ROE and deemed equity ratios approved by the Commission in this decision will result in fully prospective ROE and deemed equity ratios for two full years, which the Commission considers will help reduce regulatory lag related to the cost of capital element of rates for these years.

598. Mr. Buttke and AltaLink argued that regulatory lag increases uncertainty with respect to revenues and cash flows. While AltaLink and Dr. Carpenter noted the large amount of capital additions that are subject to deferral account proceedings for the electric transmission utilities, this is not reflective of the cash balances in the deferral accounts that these utilities have requested as part of those deferral account proceedings. No information was provided on the magnitude of these balances, without which the Commission cannot properly assess the cash flow and revenue uncertainty associated with these deferral account proceedings.

599. The Commission acknowledges that the capital additions the electric transmission utilities have requested be added to rate base as part of their deferral account proceedings are substantial. These capital additions will be assessed for prudence, as is the Commission's normal practice. The Commission is not persuaded, however, that the magnitude of capital additions currently in a deferral account presents a different level of risk than at the time of the 2016 GCOC proceeding. The Commission has addressed the argument for any potential increased risk associated with these deferral account proceedings because of the asset utilization issue in Section 9.3.2.2.

600. Based on the foregoing, the Commission considers that regulatory lag has, in general, stayed the same or improved relative to the period leading up to the 2016 GCOC decision. Accordingly, the Commission does not find that business risk has increased since the 2016 GCOC proceeding as a result of regulatory lag.

### 9.3.2.5 Clean energy initiatives

601. Dr. Carpenter indicated that policies to encourage the connection of distributed generation could reduce utilization of some electric transmission assets in the future.[770] Mr. Coyne commented that recent clean energy initiatives encourage utility customers to pursue distributed generation, and this will reduce customer demand.[771] He added that the expansion of

[769] Exhibit 22570-X0891, paragraph 48.
[770] Exhibit 22570-X0186, A60.
[771] Exhibit 22570-X0131, PDF page 73.

distributed generation could significantly impact the long-term business risk profile of the distribution utilities.[772]

602. EPCOR suggested that there is an increasing likelihood that Alberta will see growing levels of distributed generation in the near term and further into the future. It stated that the prospect of these increased levels of distributed generation creates uncertainty for utility investors because of the possibility of stranded assets, and the potential for increased costs that are not contemplated within the PBR plan.[773]

**Commission findings**

603. The issue of the impact of green energy initiatives was raised by Mr. Hevert in the 2016 GCOC proceeding. In the Commission's view, this is not an entirely new development. Given the minimal information provided in this proceeding with respect to the actual and forecast levels of distributed generation and associated impacts on the distribution systems, the Commission is not in a position to adequately assess the effect that clean energy initiatives will have on the long-term business risk profile of the affected utilities. The Commission was in the same position in the 2016 GCOC proceeding. The Commission is not persuaded that the clean energy initiatives that have been instituted since the 2016 GCOC proceeding have increased the business risk of the affected utilities.

604. The Commission has addressed the issue of stranded assets in connection with the UAD decision in Section 9.3.2.2. The Commission has addressed the issue of capital cost recovery and availability under the 2018 to 2022 PBR term in Section 9.3.2.1. In both of those sections, the Commission found that there was no increase in business risk for these two elements since the 2016 GCOC proceeding.

### 9.3.3 Business risk comparisons between the affected utilities and other jurisdictions

605. Dr. Carpenter stated that the Commission did not comment on the similarity of business risk of utilities in the U.S. and Canada in the 2016 GCOC decision.[774] In this section, the Commission will address the comparisons made as part of this proceeding by Dr. Carpenter, Mr. Coyne, Mr. Johnson and Dr. Cleary, and consider the relative regulatory risk in the U.S. and Alberta.

606. Dr. Carpenter assessed the business risk of AltaGas and the ATCO Utilities relative to their business risk in the past, and relative to the business risks of utilities in other jurisdictions. He focused particularly on utilities owned by the companies that Dr. Villadsen used as proxy groups in her evidence. Dr. Carpenter's analysis also focused on the natural gas and electricity distribution functions, which he noted the Commission had used as a benchmark in prior proceedings.[775] Based primarily on the business risk assessment undertaken by Dr. Carpenter, Dr. Villadsen argued for using the deemed equity ratios of U.S. utilities as comparators.[776]

772 Exhibit 22570-X0131, PDF page 74.
773 Exhibit 22570-X0195, paragraph 22.
774 Exhibit 22570-X0186, A24.
775 Exhibit 22570-X0186, A4.
776 Exhibit 22570-X0193.01, A17.

607. Mr. Coyne undertook a proxy group risk analysis in order to help determine his recommended equity ratios. Noting the limited number of companies in his Canadian utility proxy group, Mr. Coyne looked to a U.S. sample of low-risk electric utilities. Mr. Coyne indicated that he examined the business and financial risks of his U.S. electric proxy group, relative to those of a typical Alberta electric transmission and electric distribution utility.[777]

608. Dr. Carpenter stated that the regulatory risks facing distribution utilities in Alberta and the U.S. are similar, and both are relatively low risk. He indicated that both the U.S. regulatory regime and the Alberta regulatory regime are supportive in relation to long-term capital cost recovery, with the exception of the Commission's UAD policy.[778]

609. Dr. Carpenter noted the Commission's concerns in previous GCOC proceedings that in comparing the regulatory frameworks between the U.S. and Canada, there are differences due to the use of deferral accounts and reduced regulatory lag in Canada. Dr. Carpenter submitted that if he were to compare a jurisdiction that makes significant use of deferral accounts with a jurisdiction that does not, he would expect the jurisdiction that uses deferral accounts to have slightly lower business and regulatory risk, but the difference would not be large.[779]

610. Dr. Carpenter indicated that none of the utilities in Dr. Villadsen's U.S. gas LDC utility proxy group are exposed to commodity price risk, most of them have some form of revenue decoupling, and most have a capital tracker mechanism.[780] Dr. Carpenter expected regulatory lag to be a relatively minor contributor to business risk differentials, unless regulatory lag gives rise to a risk that invested capital will not be recovered. He noted the regulatory lag in Alberta associated with the electric transmission capital asset deferral account proceedings, and he indicated that the asset utilization proceeding will be reviewing electric transmission capital asset additions from 2014 onward.[781]

611. Noting changes associated with the 2018 to 2022 PBR term, as discussed in Section 9.3.2.1 above, Dr. Carpenter indicated he is not aware of any distribution utilities in the U.S. that are exposed to these risks. He stated that these regulatory risk factors significantly differentiate the utilities in Alberta from the utilities in Dr. Villadsen's U.S. gas LDC utility proxy group.[782]

612. Dr. Carpenter submitted that the business risk of AltaGas and the ATCO Utilities are similar to those of the utilities in Dr. Villadsen's U.S. gas LDC utility proxy group, with the exception of UAD risk and PBR risk.[783] He submitted that since the 2016 GCOC proceeding, business risk in Alberta has increased because of the Commission's decisions on the 2018 to 2022 PBR term and the asset utilization issue.[784]

613. Dr. Carpenter indicated he would not expect there to be large differences in business risk between the companies in Dr. Villadsen's U.S. gas LDC utility proxy group and the companies in her U.S. water utility proxy group. Dr. Carpenter considered the companies in Dr. Villadsen's

777 Exhibit 22570-X0131, PDF page 86.
778 Exhibit 22570-X0186, A16.
779 Exhibit 22570-X0186, A35.
780 Exhibit 22570-X0186, A36.
781 Exhibit 22570-X0186, A37.
782 Exhibit 22570-X0186, A48.
783 Exhibit 22570-X0186, A31.
784 Exhibit 22570-X0186, A62.

U.S. pipeline proxy group to constitute an upper bound of the risk that a natural gas distribution utility might face, primarily because the pipeline companies have higher business risk due to greater exposure to competition risk and more regulatory risk.[785]

614. Based on Dr. Carpenter's identification of the UAD risk and the PBR risk for AltaGas and the ATCO Utilities, which he submitted the U.S. natural gas distribution utilities do not face, Dr. Carpenter judged the business risk of AltaGas and the ATCO Utilities to be greater than the risk of Dr. Villadsen's U.S. gas LDC utility proxy group, but not as great as Dr. Villadsen's U.S. pipeline proxy group.[786] Dr. Villadsen agreed.[787]

615. Mr. Coyne summarized his comparison of business risk between the utilities in Alberta and the companies in his U.S. electric proxy group as follows:

> In sum, I find risk profiles of the U.S. proxy group and the Alberta utilities to be different but comparable. The U.S. proxy group has somewhat more risk due to the vertical integration of its utilities. But, Alberta utilities are directly exposed to changes in throughput due to declining load or loss of customers, whereby nearly half the U.S. utilities are protected from such risks through decoupling mechanisms. Both jurisdictions have established regulatory processes geared towards providing reasonably timely cost recovery and mitigating regulatory lag through the use of forecast test years and capital trackers, though Alberta's recent use of historical OM&A [operating, maintenance and administration] data and capital for rebasing its PBR plan is a significant departure from established precedents. Consequently, Alberta utilities have greater risk under a multi-year PBR plan where costs and revenues are deliberately decoupled. The reliance on a PBR framework in Alberta places earnings at greater risk and adds risk relative to the U.S. utilities that are predominantly regulated on a cost of service basis. Alberta utilities also have greater risk due to the low level of awarded returns in Alberta and the uncertainty around cost recovery stemming from the UAD Decision. These risks do not exist elsewhere in the proxy group. Overall, I consider the U.S. proxy group to have lower risk than the Alberta utilities, despite the added risk to the U.S. proxy group for its inclusion of vertically integrated electric utilities, and will consider these risk differences in combination with financial risks in recommending an equity ratio for Alberta's electric transmission and distribution utilities.[788]

616. Mr. Coyne submitted there is no substance to the belief that U.S. electric utilities are measurably riskier than the affected utilities. He noted an upgrade made by Moody's to most U.S. utilities in January 2014 to reflect its revised view that U.S. regulators have generally provided regulated utilities a reasonable opportunity to recover costs and returns.[789]

617. Mr. Coyne submitted details of the regulatory environments under which the companies in his U.S. electric proxy group operate. The 33 operating companies in his U.S. electric proxy group are primarily regulated electric transmission and distribution utilities. Of the 33 operating companies, six of them operate in two states and one operates in three states. The information provided by Mr. Coyne included the jurisdictions the companies operate in, the jurisdiction's regulatory risk assessments, the regulatory framework under which the companies operate, the

785 Exhibit 22570-X0186, A50-A51.
786 Exhibit 22570-X0186, A50-A51.
787 Exhibit 22570-X0193.01, A17.
788 Exhibit 22570-X0131, PDF pages 87-88.
789 Exhibit 22570-X0775, PDF page 55.

test year basis, whether there is revenue decoupling and the parent companies credit rating. While Mr. Coyne indicated that regulatory lag for these companies is mitigated by the use of deferral accounts,[790] no information was provided on the nature of these deferral accounts, including whether the operating companies have deferral accounts associated with capital project costs.[791]

618. Mr. Coyne summarized that (1) the majority of the companies in his U.S. electric proxy group operate under regulatory frameworks that are based on costs of service, in exclusive territories; (2) more than half of the companies operate under a forecast or partial forecast test year; (3) the parent companies have an average credit rating of A-; and (4) the companies operate in regulatory jurisdictions that are ranked slightly above the average for the constructive nature of the regulatory environment. He noted that many of the companies are vertically integrated, and he stated there is somewhat more risk because of this.

619. The information provided by Dr. Carpenter as part of his regulatory risk comparison was not as detailed as the information provided by Mr. Coyne. Dr. Carpenter focused on (1) whether there was a revenue decoupling mechanism in the states where the companies in Dr. Villadsen's U.S. gas LDC utility proxy group operate; (2) whether there was a capital tracker mechanism in the states these companies operate in; and (3) providing information about the rate case dates. Dr. Carpenter did not indicate whether all the companies were holding companies, operating companies or some combination of the two.[792]

620. Mr. Johnson's assessment of relative business risk was restricted to ATCO Gas. He submitted that, unlike most other natural gas distribution companies in Canada and the U.S., ATCO Gas has one of the lowest supply risks. Mr. Johnson noted that, unlike Union Gas and Enbridge Gas in Ontario, ATCO Gas has a weather deferral account that protects it from reduced consumption. Mr. Johnson commented that ATCO Gas has minimal market risk, and has similar regulatory risk to the other utilities in Alberta. Mr. Johnson identified that the operating risk for ATCO Gas may have increased because the urban main pipelines it proposes to acquire from ATCO Pipelines have not been tested for integrity.[793]

621. Dr. Cleary's analysis of business risk centered on numerical factors. Dr. Cleary used a CV of the earnings before interest and income taxes (EBIT)/sales ratio to quantify the level of business risk of the affected utilities and a number of the U.S. utilities used by Dr. Villadsen, Mr. Hevert and Mr. Coyne in their evidence. Based on his analysis, Dr. Cleary stated that the affected utilities have less volatility in operating profit margins, which demonstrates lower business risk than the U.S. utilities.[794]

622. Dr. Cleary also compared the affected utilities to the U.S. utilities on the basis of the CV of their earned ROEs from 2005 to 2016. Dr. Cleary concluded that the U.S. utilities displayed

790 Exhibit 22570-X0131, PDF page 87.
791 Exhibit 22570-X0132, worksheet JMC-9 Regulatory Risk.
792 Exhibit 22570-X0186, A36-A38.
793 Exhibit 22570-X0611.02, A6.
794 Exhibit 22570-X0562.01, PDF pages 82-86.

much greater volatility in ROEs than the affected utilities, which again suggests that the U.S. utilities possess greater risk than the affected utilities.[795]

623. Dr. Carpenter disagreed with the use of historical accounting-based ROEs to assess business risk in the context of setting the ROE and the deemed equity ratios. He submitted that any comparison involving historical ROEs does not constitute evidence of business risk on a go-forward basis.[796]

624. Mr. Coyne submitted that the EBIT/sales ratio represents a company's profit margin, but not its earnings. He stated that operating profits are measured by EBIT.[797] He stated that Dr. Cleary's use of the EBIT/sales ratio to compare U.S. and Canadian utilities should be dismissed because it is not related to business risk, but rather revenue mix. He contended that revenue mix is not a factor in discussing the variability of earnings.[798] Dr. Carpenter noted that the sales figures for the U.S. utilities that Dr. Cleary used in his analysis of the CV of the EBIT/sales ratios include commodity revenues, whereas this is not the case for the affected utilities.[799]

625. Dr. Carpenter noted Dr. Cleary's concern about using an analysis of the CV of the EBIT of the affected utilities, in the context of the high rate base growth of the affected utilities over the last 10 years. Dr. Carpenter calculated an alternative measure that subtracts out the impact of growth from the CV (EBIT), and indicated that the earnings volatility from 2005 to 2016 for the affected utilities is comparable to the U.S. utilities that Dr. Cleary analyzed through his CV of the EBIT/sales ratio.[800]

626. Dr. Villadsen pointed out some inconsistencies in Dr. Cleary's CV of ROE comparison. She noted that Dr. Cleary's analysis excludes all of the companies in her U.S. pipeline proxy group and her U.S. water utility proxy group, among other U.S. companies, as well as a group of publicly traded Canadian utility holding companies. Dr. Villadsen stated that Dr. Cleary's analysis used data from 2005 to 2017 for the affected utilities, but used data from 2007 to 2016 for the U.S. utilities.[801]

627. Dr. Villadsen stated that the companies in her U.S. gas LDC utility proxy group and her U.S. water utility proxy group have a much lower CV of ROE than the U.S. companies used by Dr. Cleary in his analysis.[802] Dr. Villadsen added that these lower CVs of ROE are similar to those of the affected utilities. She noted, however, that the affected utilities have earned lower returns on average than either her U.S. gas LDC utility proxy group or her U.S. water utility proxy group.[803]

628. Instead of quantifying volatility based on the CV (EBIT/sales) calculation that Dr. Cleary used, Mr. Hevert stated that the CV of net operating income (NOI) was a more appropriate

795 Exhibit 22570-X0562.01, PDF pages 89-91.
796 Exhibit 22570-X0751, A90.
797 Exhibit 22570-X0775, PDF page 49.
798 Exhibit 22570-X0775, PDF page 51.
799 Exhibit 22570-X0751, A18.
800 Exhibit 22570-X0751, A20.
801 Exhibit 22570-X0767.01, A16.
802 Exhibit 22570-X0767.01, A19.
803 Exhibit 22570-X0767.01, A19.

measure of business risk because income taxes are an operating expense for utility companies. He commented that the affected utilities have the highest CV of NOI. Mr. Hevert stated that the CV (NOI), together with the CV of earned ROE, is another measure regarding relative riskiness. Mr. Hevert submitted that the average of the CV (NOI) and the CV (ROE) shows that all proxy groups considered by the parties in this proceeding are relevant in deriving an ROE for the affected utilities.[804] Dr. Cleary questioned the informative value of averaging these two ratios.[805]

629. Mr. Hevert also described S&P's use of the volatility of profitability, when S&P weighs profitability in its assessment of financial risk. Mr. Hevert noted that when S&P's approach is applied to Dr. Cleary's data, it demonstrates that the Canadian utilities' EBIT and earnings before interest, income taxes, depreciation and amortization (EBITDA) margins are not less volatile than the U.S. utilities. Based on this, Mr. Hevert stated he does not agree with Dr. Cleary's claim that the U.S. utilities display greater operating income variability.[806]

630. Mr. Buttke submitted that equity analysts focus on differences in outcomes across regulatory jurisdictions. He noted a recent equity research article from Canadian Imperial Bank of Commerce (CIBC) in which CIBC articulated its view that differences in the U.S. and Canadian regulatory environments may make U.S. acquisitions attractive for Canadian utilities.[807] AltaLink referred to a report from February 2016 in which DBRS scored the regulatory regime for electric transmission utilities in Alberta as below average with respect to deemed equity percentages, political interference and stranded cost recovery.[808]

**Commission findings**

631. In the 2009 GCOC decision, the Commission agreed that the business risks, other than regulatory risks, of the utility business are similar as between utilities in Alberta and the U.S.[809] Based on the evidence presented during this proceeding, the Commission remains of this view.

632. With respect to regulatory risk, the Commission considered in the 2009 GCOC decision that while the differences in regulatory practice between the U.S. and Canada may have narrowed, on the whole, "Canadian utilities enjoy a more supportive regulatory environment and have less regulatory risk than their American counterparts."[810]

633. In this proceeding, both Dr. Carpenter and Mr. Coyne took the position that companies in certain U.S. proxy groups have lower regulatory risk than the utilities in Alberta. While Dr. Carpenter stated that the regulatory risks facing distribution utilities in Alberta and the U.S. are similar, he judged that because of the UAD and PBR risks the Alberta utilities face, their regulatory risk is higher than the companies in Dr. Villadsen's U.S. gas LDC utility proxy group. Mr. Coyne submitted that the companies in his U.S. electric proxy group have lower regulatory risk than the affected utilities.

[804] Exhibit 22570-X0741.01, PDF pages 58-59.
[805] Transcript, Volume 10, page 2057.
[806] Exhibit 22570-X0741.01, PDF pages 59-60.
[807] Exhibit 22570-X0179, A15.
[808] Exhibit 22570-X0141, paragraph 43.
[809] Decision 2009-216, paragraph 144.
[810] Decision 2009-216, paragraph 168.

634. Dr. Carpenter focused on the Commission's prior identification of differences between the U.S. regulatory regime and Canada with regard to the use of deferral accounts and regulatory lag. Regarding deferral accounts, Dr. Carpenter indicated that most of the companies in Dr. Villadsen's U.S. gas LDC utility proxy group have some form of revenue decoupling and most have a capital tracker mechanism. The Commission observes that in three of the states in which these companies operate, the operations are limited to less than 10 per cent of the company's total rate base.[811] Of the remaining nine states, three of them have no revenue decoupling, five have partial decoupling through the use of weather normalization, and one accounts for differences between authorized and actual revenues, except for the effects of weather.[812] The average annual revenue for these six companies is $1.7 billion.[813] Compared to ATCO Gas, which had revenue of approximately $1 billion in 2016[814] and has a weather deferral account, the Commission considers that the companies in Dr. Villadsen's U.S. gas LDC utility proxy group face much more revenue risk.

635. Dr. Carpenter mentioned the use of capital tracker mechanisms in the jurisdictions where the companies in Dr. Villadsen's U.S. gas LDC utility proxy group operate. The Commission notes that three of the nine states have no such mechanism.[815] For the six states that utilize capital tracker mechanisms, no information was submitted with respect to the capital funding that is provided through these mechanisms, compared to what has been provided for the distribution utilities in Alberta. Consequently, the Commission is not able to make an informed assessment of the value of the capital tracker mechanisms as between Alberta and these six states.

636. The Commission agrees with the submission of Dr. Carpenter that regulatory lag for the distribution utilities in Alberta is similar to that of the six companies used by Dr. Villadsen in her U.S. gas LDC utility proxy group. The period between rate cases of five years for the Alberta distribution utilities, as noted by Dr. Carpenter, is equivalent to the average years between rate cases for the companies in Dr. Villadsen's U.S. gas LDC utility proxy group.[816] The Commission is aware that the distribution utilities in Alberta will have their K-bar funding mechanism updated annually. No evidence was provided regarding the frequency of the capital tracker mechanism approval for the companies in Dr. Villadsen's U.S. gas LDC utility proxy group.

637. Based on its review above of the information provided by Dr. Carpenter about the regulatory jurisdictions under which the companies in Dr. Villadsen's U.S. gas LDC utility proxy group operate, the Commission finds Dr. Carpenter's submission that the regulatory risks facing distribution utilities in Alberta and the U.S. to be similar is unsupported.

638. The Commission considers that the wide variation in practice with respect to revenue decoupling and capital trackers does not establish any type of consistent baseline that would support Dr. Carpenter's submission that the regulatory risks facing distribution utilities in Alberta and the U.S. are similar. In addition, Dr. Carpenter's analysis did not address some of the other differences identified in the 2009 GCOC decision, including (1) the increased importance

811 Exhibit 22570-X0186, Table 1.
812 Exhibit 22570-X0186, Table 2.
813 Exhibit 22570-X0193.01, Figure 10.
814 Exhibit 22570-X0163.01, PDF page 96.
815 Exhibit 22570-X0186, Table 3.
816 Exhibit 22570-X0186, A39 and Table 4.

in the U.S. of "the reliance of market forces as a substitute for hands on regulation,"[817] which led to unexpected consequences and an unexpected exposure to business risk; (2) the use of forward test years in Canada compared to their use in the U.S.; and (3) a review of depreciation studies when stranded asset risk changes.[818]

639. The Commission also reviewed the information provided by Mr. Coyne about the regulatory jurisdictions under which the companies in his U.S. electric proxy group operate. Based on the review of this information, the Commission finds Mr. Coyne's submission that the regulatory risks for the companies in his U.S. electric proxy group are lower than the utilities in Alberta, to be unsupported.

640. The 33 operating companies in Mr. Coyne's U.S. electric proxy group operate in 27 different states. The regulatory systems in place for these 27 states are not consistent. Nine have regulatory regime rankings of above average, 15 have rankings of average, and three are ranked as being below average. The regulatory frameworks in the 27 states are (1) original cost, which is used in 18 states; (2) known and measurable adjustments, which is in place for five states; (3) average rate base, for two of the states; (4) fair value, in one state; and (5) alternative rate plans, used in one state. The test year methodologies in place are (1) fully forecasted, for 13 states; (2) historical, for 10 states; (3) partially forecasted, for two states; and (4) two states that use both fully forecasted and historical.[819] The Commission considers that the wide variation in regulatory rankings, regulatory frameworks and test year methodologies among the 27 states does not establish any type of consistent baseline that would support Mr. Coyne's submission that the regulatory risks are lower for the companies in his U.S. electric proxy group than they are for the utilities in Alberta.

641. Six of the 33 companies in Mr. Coyne's U.S. electric proxy group operate in two states, while another operates in three states. Of the six companies that operate in two states, five of them are faced with regulatory regimes that are not entirely consistent. The company that operates in three states faces three different test year methodologies. The Commission considers that the regulatory risk faced by the companies that operate in multiple states, under multiple regulatory regimes, is greater than that faced by the utilities in Alberta.

642. Similar to that of Dr. Carpenter's analysis, Mr. Coyne's analysis did not address the increased importance in the U.S. of "the reliance of market forces as a substitute for hands on regulation,"[820] which led to unexpected consequences and an unexpected exposure to business risk.

643. Dr. Carpenter and Mr. Coyne commented that the utilities in Alberta face a unique risk with respect to the UAD decision. The Commission recognized this in the 2016 GCOC decision when it determined that regulatory risk for investors in Alberta utilities had increased by some incremental but unquantifiable amount as a result of the Stores Block-UAD line of decisions.[821] Dr. Carpenter and Mr. Coyne also indicated that the rebasing and capital funding mechanism

817 Decision 2009-216, paragraph 152.
818 Decision 2009-216, Section 3.2.2.1, Section 3.2.2.3.
819 Exhibit 22570-X0132, worksheet JMC-9 Regulatory Risk.
820 Decision 2009-216, paragraph 152.
821 Decision 20622-D01-2016, paragraph 521.

risks faced by the distribution utilities in Alberta are not faced by U.S. utilities. The Commission has addressed this in Section 9.3.2.1.

644. With respect to Dr. Cleary's quantification of the differences in the business risks between the utilities in Alberta and the U.S., by calculating the CV of the EBIT/sales ratios, and the CV of the earned ROEs, the Commission agrees with the submissions of Dr. Carpenter, Mr. Coyne and Mr. Hevert that the EBIT/sales ratio is not valid for determining the volatility of operating income. The Commission also agrees with Dr. Villadsen that the CV (ROE) comparison that Dr. Cleary undertook contained inconsistencies.

645. From a quantitative perspective, the Commission takes note that (1) Dr. Carpenter's CV (EBIT) analysis indicated comparability between the utilities in Alberta and the U.S. companies analyzed by Dr. Cleary; (2) Dr. Villadsen's CV (ROE) analysis indicated similarity between the utilities in Alberta and the companies in her U.S. gas LDC utility proxy group and her U.S. water utility proxy group; (3) Mr. Hevert's analysis indicated that the utilities in Alberta have the highest CV (NOI); (4) Mr. Hevert's use of the average of the CV (NOI) and CV (ROE) indicated comparability between the utilities in Alberta and the U.S. utilities; and (5) Mr. Hevert's volatility of profitability analysis indicated that the utilities in Alberta are no less volatile than the U.S. utilities.

646. The Commission considers that there is no single accepted mathematical way to quantify business risk, as demonstrated by the number of different quantitative analyses undertaken by the parties in this proceeding,

647. Based on the determinations above, the Commission finds there is no basis to support the proposal that regulatory risk for U.S. utilities is lower than it is for the utilities in Alberta. The Commission is also satisfied that, for the reasons expressed above, the Commission's conclusion in the 2009 GCOC decision still holds; that is, "while the differences in regulatory practice between the U.S. and Canada may be narrower,"[822] on the whole, "Canadian utilities enjoy a more supportive regulatory environment and have less regulatory risk than their American counterparts."[823]

### 9.3.4 Comparability of deemed equity ratios

648. As previously mentioned, one of Dr. Villadsen's considerations in the determination of her recommended deemed equity ratio was a review of commonly approved equity ratios for regulated utilities, including those of U.S. utilities.

649. Dr. Villadsen indicated that the 37 per cent deemed equity ratio approved in the 2016 GCOC decision is several hundred bps lower than the average for other regulated utilities in Canada, and much lower than the ratios for distribution and transmission utilities in the U.S. Dr. Villadsen noted that the approved ROEs for other regulated utilities in Canada and the U.S. are higher than those in Alberta. She suggested that where the utilities in Alberta have lower ROEs and capital structures than their counterparts, the comparability standard is only satisfied if

[822] Decision 2009-216, paragraph 168.
[823] Decision 2009-216, paragraph 168.

the utilities in Alberta have significantly lower business risk. Dr. Villadsen submitted that this is not the case, based on Dr. Carpenter's evidence on business risk.[824]

650. Mr. Coyne indicated that the deemed equity ratios of 36 and 37 per cent awarded for 2016 and 2017, respectively, when combined with the approved ROE of 8.5 per cent, results in weighted equity returns of 3.06 and 3.15 per cent. He stated that these weighted returns are the lowest for comparably regulated electric utilities in all jurisdictions across Canada, with a few exceptions.[825]

651. Mr. Buttke noted DBRS's view that the deemed equity ratio of 37 per cent awarded in the 2016 GCOC decision was in the below-average category.[826]

652. Dr. Villadsen submitted that a benchmark deemed equity ratio of at least 40 per cent, before any company specific adjustments, would be necessary to place the approved equity returns in the range of comparability relative to other regulated distribution and transmission utilities.[827] Dr. Villadsen commented that while the deemed equity ratios recommended by the interveners range from 35 to 37 per cent, the average deemed equity ratios most recently approved in Canada were 36.59 per cent for electricity distributors and 39.86 per cent for natural gas distributors.[828]

653. Using the average approved ROEs and deemed equity ratios for (1) Canadian electricity distributors; (2) Canadian natural gas distributors; and (3) U.S. natural gas distributors, Dr. Villadsen calculated the resulting return on a $1 million rate base. She did the same calculation using the ROE and deemed equity ratios recommended by the UCA, Calgary and the CCA in this proceeding. The differences in the resulting returns between the use of approved figures and the use of the figures recommended by the three interveners ranged from 16 to 37 per cent when compared to the Canadian average, and from 41 to 53 per cent when compared to the U.S. natural gas distributors. Dr. Villadsen stated she did not see any evidence that suggests AltaGas and the ATCO Utilities should receive an ROE that is 16 to 37 per cent lower than that granted for other Canadian utilities.[829]

654. Mr. Coyne noted that the deemed equity ratios for the companies in his U.S. electric proxy group are significantly higher than those in Canada. He suggested this difference is explained, in part, by the different processes used by Canadian and U.S. regulators for setting equity ratios. Mr. Coyne consequently did not recommend any adjustment to account for the different equity ratios between Canadian utilities and the companies in his U.S. electric proxy group.[830]

655. The UCA noted the Commission's previously expressed preference for an approach to estimating the cost of capital that relies on sound principles of finance, as opposed to simply looking to the awards of other regulators developed on the basis of different records and under different circumstances. It noted and agreed with the observation of the chair of this proceeding

824 Exhibit 22570-X0193.01, A82.
825 Exhibit 22570-X0131, PDF page 82.
826 Exhibit 22570-X0179, A13.
827 Exhibit 22570-X0193.01, A83.
828 Exhibit 22570-X0767.01, A5.
829 Exhibit 22570-X0767.01, A98.
830 Exhibit 22570-X0131, PDF page 87.

that relying on the returns approved by other regulators necessarily imports circularity into the process. The UCA also agreed with the chair that the relevant consideration is the market expectation of the cost of capital, and not what other regulators are allowing.[831]

**Commission findings**

656. With respect to the comparability of the deemed equity ratios as between Alberta and the U.S., the Commission agrees with the following submission from Mr. Coyne:

> With respect to the differences in equity ratios, this is explained in part by the process U.S. regulators use for setting equity ratios versus their Canadian counterparts, where equity ratios are deemed. As such, I have not recommended an adjustment for the difference in equity ratios between the U.S. and Canada, as I believe the difference may be justified by the use of deemed equity ratios in Canada versus greater reliance by U.S. regulators on actual capital structures in comparison to peer companies.[832]

657. Mr. Coyne's observation is supported by DBRS in its analysis of the regulatory framework for utilities in Canada and the U.S. DBRS stated:

> For some utilities, returns are based on the actual capital structure which is set within a range determined by the state regulator. Pennsylvania is an example, where the commission intervenes only if quarterly disclosed equity ratios fall outside a reasonable range.[833]

658. In the 2009 GCOC decision, the Commission found that that the equity ratios in the U.S. are likely higher as a result of the ability of management in certain U.S. jurisdictions to set the capital structure within a range acceptable to the regulator. This is a differentiating point between regulation of U.S. and Canadian utilities and an indication that allowed capital structures for U.S. utilities should not be held up as representative of the capital structures required by Canadian utilities in order to satisfy the fair return standard.[834] The Commission continues to be of this view.

659. Dr. Villadsen indicated that the average of the deemed equity ratios most recently awarded in Canada is 36.59 per cent for electricity distributors and 39.86 per cent for natural gas distributors. These figures include the deemed equity ratios awarded by the Commission in 2017 for the utilities in Alberta.[835] In order to make a valid comparison between the deemed equity ratios approved in Alberta and other Canadian jurisdictions, the Commission finds that the deemed equity ratios for the utilities in Alberta must be excluded from the figures presented by Dr. Villadsen. Omitting the deemed equity ratios awarded by this Commission, the averages for the other Canadian jurisdictions are (1) 40 per cent for Canadian gas distributors; (2) 36.41 per cent for Canadian electricity distributors; and (3) 35 per cent for Canadian electric transmission companies.[836]

[831] Exhibit 22570-X0913, paragraph 192.
[832] Exhibit 22570-X0131, PDF page 87.
[833] Exhibit 22570-X0842, PDF page 19.
[834] Decision 2009-216, paragraph 193.
[835] Exhibit 22570-X0766, PDF pages 49-50.
[836] Exhibit 22570-X0766, PDF pages 49-50.

660. With regard to Dr. Villadsen's comparison of the deemed equity ratios for Canadian gas distributors, which average 40 per cent in other jurisdictions, the Commission observes that there is a wide range of deemed equity ratios that make up this average, from 30 to 46.50 per cent. The deemed equity ratios of 37 per cent and 39 per cent for ATCO Gas and AltaGas, respectively, approved in Section 9.11 and Section 10, respectively of this decision are within this range. Further, when these deemed equity ratios are compared to the approved deemed equity ratio of 36 per cent for the two large gas distribution utilities in Ontario, Union Gas Limited and Enbridge Gas Distribution Inc., the deemed equity ratios of ATCO Gas and AltaGas are higher.[837] With regard to comparing the deemed equity ratio for electric distribution and transmission utilities, the deemed equity ratio of 37 per cent approved in Section 9.11 of this decision is 59 bps greater than the average for other Canadian electricity distributors, and 200 bps greater than the average for other Canadian electric transmission companies.

## 9.4 Industry financing practices

661. Mr. Hevert indicated that one of the focuses of his recommended deemed equity ratio was on industry financing practices.[838] He submitted that the capital structure of a utility must support the financial strength of the utility during normal market conditions and during periods of market uncertainty. Mr. Hevert described a key financing practice known as "maturity matching" that applies when optimizing capital structure. The goal of maturity matching is to align the average life of the securities in the capital structure with the average lives of the capital assets being financed. He explained that the perpetual life of common equity mitigates refinancing risk, whereas relying more heavily on debt increases the risk of refinancing maturing debt obligations during less accommodating market environments. Mr. Hevert submitted that the long-term nature of refinancing risks is not reflected in the near-term, pro forma credit metrics used by the Commission to determine deemed equity ratios.[839]

662. Mr. Hevert stated that capital structure management is focused on multiple factors, some that are company specific and others that are market-dependent. He indicated that these factors are dynamic and complex, and are forward looking. Mr. Hevert suggested that utility capital structure decisions recognize the long-term nature of the assets that support utility operations, the need for short-term financial liquidity, and the fact that capital market conditions are not always accommodating. He submitted that because utility operations are so dependent on capital market access, his belief is that those considerations should extend to the factors that will enable the cost-effective, efficient and timely access to capital over the long term under both constrained and accommodating market conditions.[840]

### Commission findings

663. Financial strength of the utilities is one of the factors the Commission considered as part of its determination of the approved ROE and deemed equity ratios for 2018 to 2020. This is evidenced by the Commission's targeting of credit ratings in the A-range for the affected utilities, as discussed in Section 9.6 and Section 9.7. An A-range credit rating should support the financial strength of the utilities under varying market conditions, and help to ensure capital attraction.

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837 Exhibit 22570-X0766, PDF page 49.
838 Exhibit 22570-X0153.01, PDF page 7.
839 Exhibit 22570-X0153.01, PDF page 104.
840 Exhibit 22570-X0741.01, PDF page 75.

664. Mr. Hevert commented on the long-term nature of refinancing risks, but he did not provide any type of detailed analysis that would help guide the Commission with respect to this risk. Given the long-term nature of utility assets, and especially considering that the age of the electricity transmission assets completed under the big build will be less than 10 years at the end of 2020, the Commission considers that assessing long-term refinancing risk for the utilities in Alberta will involve long-term assumptions about bond markets, which could change substantially over the ensuing years.

665. The Commission observes that the affected utilities have issued a substantial amount of 30-year debt and some 40- and 50-year debt as well in recent years. All this debt matures as a balloon payment at the end, except for ENMAX's ACFA funding, which is a debenture by which capital is paid off during the term. These debt issuances typically fund long-life assets of 40 to 50 years. At the end of 30 years, where a 40-year asset has been funded by 30-year debt, approximately three-quarters of the asset's cost will have been recovered already in depreciation rates. Accordingly, the refinancing risk is only on one quarter of the original cost, which will also be reduced by the equity component, and that is after 30 years of accumulated inflation so any historic cost would not be significant, and the residual refinancing risk is only for a term of 10 years. The Commission has not been presented with any evidence that would indicate that this risk is substantial.

666. Even if rates did increase dramatically, debt costs are a flow-through item to ratepayers and the regulated firm can pass through these costs. In that way the utility is insulated from any refinancing risk.

667. Mr. Hevert stated that the perpetual life of common equity mitigates against refinancing risk. The Commission considers that unless the utility is financed 100 per cent by equity, there will always be some level of refinancing risk; however, that risk is minimal and flowed through to ratepayers.

## 9.5 Factors raised by FortisAlberta

668. FortisAlberta submitted that the determination of a deemed equity ratio for 2018 to 2020 should recognize the importance of equity funding in meeting the utility's overall capital funding requirements, and seek to foster the utility's ability to attract capital from both equity and debt investors on reasonable terms, and in required amounts. It contended that the need to foster equity funding is heightened during the 2018 to 2020 period, because of the 2018 to 2022 PBR term, and the provincial government's climate leadership plan.[841] FortisAlberta stated it will be an important contributor to the development of distributed generation in Alberta, and it indicated this will require significant amounts of capital investment. It submitted that the Commission's approval of an increase in the utility's deemed equity ratio will help to ensure that the required capital is available.[842]

669. FortisAlberta commented that the large amount of debt that currently comprises its capital structure may not be sustainable as capital markets continue to evolve, and future debt rates may not always be as low as they currently are. It submitted that these concerns with debt

[841] Exhibit 22570-X0228, paragraph 4.
[842] Exhibit 22570-X0228, paragraph 35.

should be recognized by the Commission and addressed by increasing the deemed equity ratio, in order to attract more equity investment.[843]

670. Mr. Thygesen responded that the credit spreads for FortisAlberta have decreased almost 50 per cent since the time of the 2016 GCOC oral hearing, and its recent debt issue in September 2017 had a credit spread that was much lower than the spread on the debt issues in 2015 and 2016.[844] He indicated that FortisAlberta does not face any refinancing risk until 2034.[845]

671. FortisAlberta cautioned that the reduction to its deemed equity ratio as a result of the 2016 GCOC decision potentially impairs its ability to attract equity in the future. It explained that because it has one equity investor, and that equity investor has investments in other regulated utilities, FortisAlberta's ability to obtain future equity injections may be impaired to the extent that it cannot demonstrate that it represents an investment possessing value, comparable to the other regulated utilities owned by its investor.[846]

### Commission findings

672. As discussed in Section 9.11, the Commission considers that the ROE and deemed equity ratio it has approved for FortisAlberta as part of this decision satisfies the fair return standard. The fair return standard includes consideration of the capital attraction, financial integrity and comparability factors. The Commission considers this fosters FortisAlberta's ability to attract debt and equity capital.

673. FortisAlberta stated that the large amount of debt in its capital structure may not be sustainable as capital markets evolve, but it provided no evidence about what this evolution may entail. The submission from FortisAlberta that future debt rates may not always be as low as they currently are, is likewise not supported by any evidence.

674. With respect to the potential impairment of FortisAlberta's ability to attract equity in the future, the Commission considers that FortisAlberta's equity investor would likely assess the approved ROE as well as the actual ROEs that have been achieved by FortisAlberta. The actual ROEs achieved by FortisAlberta have averaged 10.2 per cent over the years 2010 to 2016.[847]

## 9.6 Maintaining credit ratings in the A-range

675. In the 2016 GCOC decision, the Commission noted its historical recognition of the importance of maintaining a credit rating in the A-range. The Commission explained that an objective of the analysis it undertook when establishing the approved deemed equity ratios was to ensure that the deemed equity ratio, when combined with the approved ROE, would achieve target credit ratings in the A-range.[848]

676. In this proceeding, the Commission asked Dr. Villadsen, Dr. Carpenter, Mr. Buttke, Mr. Coyne, Mr. Thygesen, Mr. Madsen, Mr. Bell, Dr. Cleary and Mr. Johnson to comment on

843 Exhibit 22570-X0228, paragraphs 16-17.
844 Exhibit 22570-X0551, paragraphs 158-159.
845 Exhibit 22570-X0551, paragraph 160.
846 Exhibit 22570-X0228, paragraphs 19-20, 22.
847 Exhibit 22570-X0561.01, worksheet WP 4 – ROE Variation.
848 Decision 20622-D01-2016, paragraph 345.

whether it should continue to recognize the importance of maintaining a credit rating in the A-range for the affected utilities.

677. Mr. Hevert stated that he considered the importance of maintaining an A-range credit rating when he developed his recommended deemed equity ratio.[849] Dr. Carpenter indicated his agreement with the comments provided by Dr. Villadsen and Mr. Buttke.[850]

678. Mr. Hevert,[851] Mr. Coyne,[852] Dr. Villadsen[853] and Mr. Buttke[854] commented that having A-range credit ratings helps ensure the affected utilities are able to attract capital from the long-term Canadian bond market in almost all market conditions. Mr. Coyne noted that the BBB bond market is not as well established in Canada as it is in the U.S., and consequently there is less trading of sub-A rated debt in the Canadian credit market.[855] Mr. Buttke suggested that a number of large Canadian insurance companies may not buy long-term utility debt that is BBB rated.[856] Mr. Buttke's suggestion was supported by Mr. Coyne, who stated that life-insurance companies and pension funds account for the bulk of the demand in long-term debt, and many of these companies are limited to A-range rated securities.[857]

679. Mr. Buttke submitted that while credit ratings in the A-range are not guarantees of a fair rate of return, they help reassure investors that some minimum level of return will likely be forthcoming in this GCOC proceeding, as well as future GCOC proceedings.[858]

680. Dr. Villadsen stated that bond investors and DBRS have recognized the Commission's A-range credit rating policy as a sign of regulatory support for the utilities.[859] Mr. Buttke suggested that if the Commission renounced this policy, investors would change their assumption about the level of regulatory support in Alberta.[860] Dr. Villadsen commented that debt investors and credit rating agencies would have a negative perception of any deviation in the Commission's policy.[861]

681. Dr. Villadsen stated that all else equal, sub-A rated debt has higher rates than debt rated in the A-range.[862] Mr. Madsen and Mr. Thygesen,[863] as well as Dr. Cleary,[864] provided information on the current credit spreads for BBB and A-rated utilities, which suggested that the differences were in the range of 18 bps to 30 bps. Mr. Coyne submitted that the difference in credit spreads has narrowed at the current time because of the strong credit markets.[865]

849 Exhibit 22570-X0153.01, PDF page 109.
850 Exhibit 22570-X0308, AUI/ATCO-AUC-2017NOV17-001.
851 Exhibit 22570-X0153.01, PDF page 109.
852 Exhibit 22570-X0286, EPC-AUC2017NOV21-011.
853 Exhibit 22570-X0308, AUI/ATCO-AUC-2017NOV17-001.
854 Exhibit 22570-X0749, A16.
855 Exhibit 22570-X0775, PDF page 12. Transcript, Volume 6, page 1263.
856 Exhibit 22570-X0749, A16.
857 Exhibit 22570-X0775, PDF page 12.
858 Exhibit 22570-X0308, AUI/ATCO-AUC-2017NOV17-001.
859 Exhibit 22570-X0308, AUI/ATCO-AUC-2017NOV17-001.
860 Exhibit 22570-X0308, AUI/ATCO-AUC-2017NOV17-001.
861 Exhibit 22570-X0767.01, A111.
862 Exhibit 22570-X0308, AUI/ATCO-AUC2017NOV21-001.
863 Exhibit 22570-X0701.01, CCA-AUC-2018JAN26-001.
864 Exhibit 22570-X0675, UCA-AUC-2018JAN26-005.
865 Exhibit 22570-X0775, PDF page 12.

Mr. Buttke commented that the magnitude of the credit spread differences would vary, depending on market conditions.[866] He pointed out that during the 2016 GCOC proceeding, the Royal Bank of Canada estimated that the relative spread on 30-year debt between A-rated bonds and BBB-rated bonds could have been nearer 100 bps.[867]

682. Mr. Thygesen, Mr. Madsen and Dr. Cleary focused on this difference in debt rates, as well as the corresponding reduction in the deemed equity ratio, that they suggested could accompany the targeting of credit ratings in the sub-A range.

683. Mr. Thygesen and Mr. Madsen submitted that the Commission should only target an A-range credit rating if the higher interest costs being avoided by targeting the A-range are greater than the higher cost of equity capital that results from maintaining the A-range credit rating.[868] Mr. Bell echoed these comments when he submitted that the lowest cost alternative to provide safe and reliable utility service should be incorporated into customer rates.[869]

684. Mr. Johnson stated the Commission's primary responsibility is to the fair return standard, and suggested that an A-range credit rating should only be maintained without exceeding what is required by the fair return standard.[870]

685. Dr. Cleary noted that there is a trade-off in deciding how much relief to provide the utilities, in order to help them achieve a credit rating in the A-range.[871] He suggested that if it becomes extremely expensive to provide high equity ratios or an approved ROE to maintain an A-range credit rating, it could make sense to allow one metric to slip a little bit into the triple B plus range, rather than to strictly target credit metrics consistent with an A-range credit rating.[872] Dr. Cleary submitted that the Commission should look at the circumstances of each utility, and use judgment as well as analysis, including a cost-benefit analysis, to determine if it is too expensive or infeasible to maintain an A-range credit rating.[873]

686. Mr. Madsen developed a quantitative model as a cost/benefit analysis.[874] Based on the outputs of his model, under different scenarios, Mr. Madsen submitted that a reduction in the deemed equity ratios could be made, up to a certain limit. He cautioned that his submission is dependent upon the credit spreads used as inputs to his model.[875]

687. Mr. Coyne contended that Mr. Madsen's conclusions do not account for the additional cost of equity that would be required due to the increased financial risk. Mr. Coyne stated that an equity investor with an increase in financial risk because of a lower deemed equity ratio would not be expected to have the same cost of equity as an investor with lower financial risk.[876]

866 Exhibit 22570-X0308, AUI/ATCO-AUC2017NOV21-001.
867 Exhibit 22570-X0749, A16.
868 Exhibit 22570-X0701.01, CCA-AUC-2018JAN26-001.
869 Exhibit 22570-X0675, UCA-AUC-2018JAN26-005.
870 Exhibit 22570-X0667, CALGARY-AUC-2018JAN26-001.
871 Exhibit 22570-X0675, UCA-AUC-2018JAN26-005.
872 Transcript, Volume 10, page 2055.
873 Exhibit 22570-X0675, UCA-AUC-2018JAN26-005.
874 Exhibit 22570-X0701.01, CCA-AUC-2018JAN26-001.
875 Exhibit 22570-X0701.01, CCA-AUC-2018JAN26-001.
876 Exhibit 22570-X0775, PDF page 11.

688. Mr. Coyne submitted that the logic of finding the lowest possible credit rating such that the marginal cost of debt does not exceed the cost of equity ignores the comparability requirement of the fair return standard.[877]

**Commission findings**

689. After considering the evidence and submissions, the Commission is not prepared, at this time, to depart from its historical practice of maintaining credit ratings in the A-range for the affected utilities.

690. Mr. Madsen, Mr. Thygesen and Dr. Cleary focused their attention on the quantitative aspect of the trade-off between the cost of increased ROE and deemed equity ratio needed to maintain the lower debt cost associated with an A-range credit rating. The Commission considers that while such a quantitative analysis is required, it is also necessary to consider qualitative factors. The Commission agrees with Dr. Villadsen that this matter cannot be addressed simply by considering the differences in debt rates between A-range debt and BBB-rated debt.

691. Mr. Madsen cautioned that the results of his quantitative analysis are dependent upon the credit spreads used, which at this time are quite narrow as between A-rated debt and BBB-rated debt. However, no evidence was presented as to whether this narrow difference is a long-term trend. The Commission also agrees with Mr. Coyne that Mr. Madsen's quantitative model does not demonstrate whether he accounted for the additional cost of equity that might be required due to lower deemed equity ratios being awarded.

692. The Commission finds that the qualitative factors put forward by Dr. Villadsen, Mr. Hevert, Mr. Coyne and Mr. Buttke are valid considerations, and provide support for targeting credit ratings in the A-range.

693. S&P's current regulatory advantage assessment of Alberta is strong, but still on a negative trend.[878] The Commission considers it important to maintain this strong regulatory assessment, and targeting the maintenance of credit ratings in the A-range plays an important role in achieving this.

694. 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. Generally, utilities with A-range credit ratings can obtain debt rates that are lower than utilities with sub-A rated debt. Lower debt rates help bolster financial integrity. Credit ratings in the A-range help foster the attraction of debt investors, as submitted by Mr. Hevert, Mr. Coyne, Dr. Villadsen and Mr. Buttke. Regarding the attraction of equity capital, Mr. Buttke submitted that while credit ratings in the A-range are not guarantees of a fair rate of return, they help reassure investors that some minimum level of return will likely be forthcoming. The Commission considers that maintaining credit ratings in the A-range, when combined with a sufficient ROE, meets the fair return standard.

877 Exhibit 22570-X0775, PDF pages 11-12.
878 Exhibit 22570-X0141, paragraph 34.

695. Based on these findings, in combination with the ROE approved in Section 8.8 above, 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 2018 to 2020.

### 9.7 Credit ratings and credit metric analysis

696. Dr. Villadsen,[879] Mr. Hevert,[880] Mr. Coyne,[881] Mr. Madsen[882] and Dr. Cleary[883] 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.

#### 9.7.1 Financial ratios, capital structure and actual credit ratings

697. 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.

698. 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 2016 GCOC decision, the Commission has historically assessed three principal credit metrics:[884]

- 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.[885] In the Commission's credit metric model, it is calculated by adding the net income and the

879 Exhibit 22570-X0193.01, A5.
880 Exhibit 22570-X0153.01, PDF page 123.
881 Exhibit 22570-X0131, PDF pages 100-101.
882 Exhibit 22570-X0557, paragraph 118.
883 Exhibit 22570-X0562.01, PDF page 6.
884 Decision 20622-D01-2016, paragraph 356.
885 Exhibit 20622-X0089, PDF page 736.

depreciation collected and dividing the resulting figure by the sum of the deemed mid-year debt for rate base and CWIP.

699. In the 2016 GCOC decision, the Commission took guidance from the EBIT coverage ratio threshold used in the 2009 GCOC proceeding,[886] in which the Commission observed that an EBIT coverage of 2.0 was the minimum threshold associated with regulated utilities with an A-range credit rating.

700. In the 2016 GCOC decision, the Commission also placed greater weight on S&P's credit metric benchmarks for FFO coverage and FFO/debt, using a "low volatility scale." The Commission noted that the credit metric benchmarks used by S&P for an A-range credit rating are an FFO coverage ratio of 2.0 to 3.0, an FFO/debt ratio of 9.0 per cent to 13.0 per cent, and an EBITDA coverage ratio of 2.5 to 4.0. The Commission did not focus on the EBITDA coverage ratio in the 2016 GCOC decision.[887]

701. In the 2016 GCOC decision, the Commission also calculated the deemed equity ratios that were required to attain the minimum credit metrics necessary to maintain an A-range credit rating for a typical taxable distribution utility, a typical non-taxable distribution utility, a typical taxable transmission utility and a typical non-taxable transmission utility. The Commission has performed the same calculations as part of this decision.

**Mr. Hevert's comments on credit metrics**

702. Mr. Hevert stated that while credit metrics are important inputs into the credit rating process, they are only one consideration used by the credit-rating agencies.[888] He explained that in assessing credit ratings, DBRS and S&P consider many factors, including the quality of the regulatory regime, as well as historical and forward-looking credit ratios.[889]

703. Mr. Hevert noted that there is considerable variation in the historical Rule 005 data that is used by the Commission and, as a result, it is not certain that the parameters used in the Commission's credit metric calculations will equal those likely to be observed in 2018, 2019 and 2020.[890]

704. Mr. Hevert demonstrated how changes in two parameters (mid-year CWIP percentage and depreciation) would have affected the FFO/debt credit metric calculated by the Commission in the 2016 GCOC decision. He indicated that if the actual CWIP percentage is higher than expected, this will reduce actual cash flows and the FFO/debt ratio. If the actual depreciation parameter is lower than expected, this will also reduce actual cash flows and the FFO/debt ratio. Mr. Hevert pointed out that the Commission should understand how these variations affect the credit metrics.[891]

705. Mr. Hevert indicated that when S&P calculates ratios using debt, it makes several adjustments to increase debt balances to reflect debt-like financial obligations. He suggested that

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[886] Decision 20622-D01-2016, paragraphs 357-358, 399.
[887] Decision 20622-D01-2016, paragraphs 393, 399.
[888] Exhibit 22570-X0153.01, PDF page 111.
[889] Exhibit 22570-X0153.01, PDF page 121.
[890] Exhibit 22570-X0153.01, PDF pages 111-112.
[891] Exhibit 22570-X0153.01, PDF pages 114-119.

if these adjustments are not reflected in the Commission's credit metric calculations, then the FFO/debt ratio would be overstated.[892] He noted that S&P focuses on variability in earnings when it assesses future expected credit quality, while the only source of variation in the Commission's credit metric calculations is the deemed equity ratio.[893]

**Mr. Coyne's comments on credit metrics**

706. Mr. Coyne indicated that credit metrics are one consideration in assessing financial risk.[894] He acknowledged the three credit metrics used by the Commission in the 2016 GCOC decision, and the A-range thresholds established for these metrics by S&P. He stated that another core ratio used by S&P is the debt/EBITDA ratio, and that the A-range threshold used by S&P for this ratio is 4.0 to 5.0.[895]

707. Mr. Coyne calculated the following ratios as part of his credit metric analysis (1) EBIT coverage; (2) EBITDA coverage; (3) FFO coverage; (4) FFO/debt; and (5) debt/EBITDA.[896]

708. Mr. Coyne calculated and reported these credit metrics as of December 31, 2016, for (1) each of the companies in his U.S. electric proxy group; (2) each of the companies in his Canadian utility proxy group; (3) each of the companies in his North American electric proxy group; (4) the transmission utilities in Alberta; (5) the non-taxable transmission utilities in Alberta; (6) the distribution utilities in Alberta; and (7) the non-taxable distribution utilities in Alberta.[897]

709. Based on the credit metrics he calculated and reported, Mr. Coyne submitted that the utilities in Alberta are well below the median for his North American utility proxy group, and in the majority of cases, are very near the bottom, which indicates a financially vulnerable risk profile. He added that all of the interest coverage ratios for the affected utilities are very low, when compared to his North American utility proxy group. Mr. Coyne submitted that this additional financial risk needs to be considered, in combination with the elevated business risks, to determine an appropriate level of equity for the affected utilities.[898]

710. Mr. Coyne pointed out that, based on his credit metric calculations, the non-taxable distribution and transmission utilities in Alberta would fall below S&P's A-range thresholds for the EBIT coverage ratio and the debt/EBITDA ratio, and the transmission utilities would fall below the debt/EBITDA ratio. He stated that the deemed equity ratios approved in 2016 do not meet the Commission's objective of satisfying the credit metric requirements for an A-range credit rating.[899]

892 Exhibit 22570-X0153.01, PDF page 113.
893 Exhibit 22570-X0153.01, PDF pages 113-114.
894 Exhibit 22570-X0131, PDF page 89.
895 Exhibit 22570-X0131, PDF page 91.
896 Exhibit 22570-X0131, PDF pages 92-93.
897 Exhibit 22570-X0131, PDF pages 91-92.
898 Exhibit 22570-X0131, PDF page 94.
899 Exhibit 22570-X0131, PDF pages 98-99.

### Mr. Thygesen's comments on credit metrics

711. Mr. Thygesen submitted that any credit metric calculations for EPCOR should use the ACFA debt rate.[900] He suggested that the reason why EPCOR's embedded average debt rates are greater than an average Alberta utility is because since 2013, the credit spreads for Westcoast Energy Inc., one of the four comparator companies EPCOR uses to establish its stand-alone debt rates, are much higher than the other three companies in the comparator group. Mr. Thygesen suggested that Westcoast Energy Inc. has little in common with EPCOR, and EPCOR should not include this company as part of its comparator group. He recommended that any credit metric calculations for EPCOR as part of this GCOC proceeding reflect the exclusion of Westcoast Energy from the comparator group.[901]

### EPCOR's comments on credit metrics

712. EPCOR reiterated its position that any issue with respect to its debt rates is beyond the scope of this GCOC proceeding. It stated it continues to address the issues raised by Mr. Thygesen in its tariff-related proceedings. EPCOR added it has placed evidence on the record that completely refutes Mr. Thygesen's claim about the use of Westcoast Energy skewing the credit spread information, which EPCOR submitted was ignored by Mr. Thygesen.[902] EPCOR pointed out that debt rates do not impact the FFO/debt credit metric, which is the metric that Mr. Madsen places the majority of weight on in his credit metric analysis.[903]

713. EPCOR noted that the pro forma credit metrics for its distribution and transmission functions are generally lower than those the Commission calculates for the generic distribution and transmission utilities. EPCOR stated the differences are because it has a higher than average embedded debt rate, a lower than average depreciation rate, a lower than average CWIP percentage, and because it is income tax exempt. It noted that DBRS foresees a deterioration in the cash-flow to debt ratios for EPCOR's distribution and transmission functions, and DBRS expects these ratios to decrease to the BBB-rating range.[904]

### Mr. Bell's comments on credit metrics

714. Mr. Bell's submitted that his base case credit metrics show that an increase in the deemed equity ratio is not required. He indicated that a deemed equity ratio of 35 per cent would satisfy the EBITDA coverage, FFO interest coverage and FFO/debt targets for an A-range credit rating established by S&P, and a slightly higher deemed equity ratio would satisfy the thresholds established by DBRS.[905]

### Mr. Madsen's comments on credit metrics

715. Mr. Madsen agreed with the Commission's increased reliance, as part of the 2016 GCOC decision, on the S&P credit metrics and related thresholds necessary for an A-range credit rating.[906]

900 Exhibit 22570-X0551, paragraph 19.
901 Exhibit 22570-X0551, paragraphs 20-27.
902 Exhibit 22570-X0733, A45.
903 Exhibit 22570-X0733, A43.
904 Exhibit 22570-X0195, paragraphs 67, 70, 74, 77.
905 Exhibit 22570-X0559, A17.
906 Exhibit 22570-X0557, paragraph 165.

716. Mr. Madsen stated that forecast capital expenditures for the Alberta utilities in 2018, 2019 and 2020 are lower than historical levels, which will also result in lower debt issuances over this period. He commented that because of this, there will be less pressure on credit metrics. Mr. Madsen submitted that this reduces business risk, and supports his conclusion for lower deemed equity ratios over the test period.[907]

717. As part of Mr. Madsen's credit metric analysis, he estimated the weighting that the Commission applied to the three credit metrics it used in the 2016 GCOC decision.[908] Mr. Madsen indicated that the input parameters he used in his credit metric analysis were calculated using information from the Rule 005 filings the utilities submitted in 2017, which reported on the results for 2016. He used a simple average for debt rates, and a weighted average for depreciation and CWIP. Mr. Madsen submitted that the most current information from a single year should be used for the input parameters, rather than a number of historical years, because the deemed equity ratio is being approved on a forward basis.[909]

718. Based on his credit metric calculations, and his estimation of the weighting the Commission placed on the three credit metrics in the 2016 GCOC decision, Mr. Madsen concluded that a base level equity ratio of 35.8 per cent would allow the transmission utilities to achieve an A-range credit rating, and a base level equity ratio of 36.5 per cent would allow the distribution utilities to achieve an A-range credit rating.[910]

719. Turning to his assessment that business risk for the transmission utilities has decreased since the 2016 GCOC decision into account, Mr. Madsen stated that the deemed equity ratio for the Alberta transmission utilities should be set at a base level of 35.5 per cent. Combining his assessment of a decline in the business risk of the distribution utilities since the 2016 GCOC decision, with their higher overall credit metric levels, Mr. Madsen stated that the deemed equity ratio for the Alberta distribution utilities should be set at a base level of 36 per cent. He noted that neither of these recommended base levels reflect the possible adoption of the future income tax method.[911]

### Dr. Villadsen's comments on credit metrics

720. Dr. Villadsen recommended that the Commission select a capital structure that is sufficient to meet credit metric thresholds toward the middle of the published guidelines of all the major credit-rating agencies, including DBRS, Fitch Ratings, Moody's Investor Services (Moody's) and S&P.[912]

721. Dr. Villadsen suggested that even without a credit-rating downgrade, operating with credit metrics at the low end of the scale could place AltaGas and the ATCO Utilities at risk of decreased access to credit, or higher debt rates, in the event of an unexpected financial downturn in the economy.[913]

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907 Exhibit 22570-X0557, paragraphs 220 and 222.
908 Exhibit 22570-X0557, paragraph 243.
909 Exhibit 22570-X0557, paragraphs 244-249.
910 Exhibit 22570-X0557, paragraphs 253 and 261.
911 Exhibit 22570-X0557, paragraphs 262-264.
912 Exhibit 22570-X0193.01, A85, A90.
913 Exhibit 22570-X0193.01, A85.

722. Dr. Villadsen was concerned with the Commission's reliance in the 2016 GCOC decision on S&P's credit metric thresholds using the low volatility table. She indicated that S&P only applies the low volatility table if it assesses the utility's regulatory advantage score as being strong. While she acknowledged that S&P's regulatory advantage score for Alberta is strong, she noted it is with a negative trend.[914] Dr. Villadsen submitted that, based on Dr. Carpenter's evidence, the business risk and regulatory risk for AltaGas and the ATCO Utilities is increasing, which reduces their ability to fit into S&P's low volatility category. She also noted the concerns expressed by credit rating agencies about the quality of regulatory support in Alberta. Consequently, Dr. Villadsen cautioned that it is risky to assume that S&P, as well as other rating agencies, will continue to evaluate credit metrics under the assumption of a strong regulatory environment in Alberta.[915]

723. Noting that the Commission placed greater weight on S&P's credit metric guidelines in the 2016 GCOC decision, but considering her concerns with only relying on the low end of the credit metric guidelines established under S&P's low volatility table, Dr. Villadsen submitted that it is more appropriate for the Commission to target the two FFO-based credit metrics using the point of overlap between S&P's low volatility table and medial volatility table. This would set the FFO interest coverage ratio threshold at 3.0, and the FFO/debt ratio threshold at 13.0.[916]

724. Dr. Villadsen noted that in Mr. Bell's credit metric calculations, he incorrectly assumed an income tax rate of 27 per cent when he calculated EBIT and EBITDA.[917] She noted that Mr. Madsen did the same when he calculated EBIT.[918] She stated that this is greater than the effective income tax rate that AltaGas and the ATCO Utilities will have under the flow-through income tax method, and consequently, the EBIT and EBITDA figures are too high.[919] While she acknowledged the Commission's determinations in the 2011 GCOC decision about using the statutory income tax rates to calculate EBIT, Dr. Villadsen submitted that it is proper to consider credit metrics in a manner that is consistent with the income tax method that will be used during the test period.[920] She stated that calculating EBIT and EBITDA using the effective tax rates has a substantial impact.[921]

725. Dr. Villadsen noted that Mr. Bell did not calculate the debt/EBITDA ratio.[922] She calculated the debt/EBITDA ratio using Mr. Bell's inputs, and advised that it would require a deemed equity ratio of 41 per cent in order to meet the minimum standard of S&P.[923]

726. Dr. Villadsen disagreed with Mr. Bell's conclusion that based on his credit metric calculation, a deemed equity ratio slightly higher than 35 per cent would satisfy the DBRS thresholds for an A-range credit rating. She submitted that the required equity ratio would have

914 Exhibit 22570-X193.01, A88.
915 Exhibit 22570-X193.01, A89.
916 Exhibit 22570-X0193.01, A90.
917 Exhibit 22570-X0767.01, A105.
918 Exhibit 22570-X0767.01, A107.
919 Exhibit 22570-X0767.01, A105.
920 Exhibit 22570-X0767.01, A106.
921 Exhibit 22570-X0767.01, A108.
922 Exhibit 22570-X0767.01, A101-A102.
923 Exhibit 22570-X0767.01, A104.

to be at least 39 per cent, and this would only meet the low end of the DBRS threshold for FFO/debt.[924]

727. Dr. Villadsen stated that Mr. Madsen's approach of attempting to infer the weightings the Commission assigned to the three credit metrics it used in the 2016 GCOC decision was confusing and arbitrary, and yields nonsensical results. Dr. Villadsen pointed out that Mr. Madsen ignored his calculated credit metric results when he recommended deemed equity ratios.[925]

**AltaLink's comments on credit metrics**

728. AltaLink suggested that because its business risk is now higher than it was during the 2016 GCOC proceeding, the obvious conclusion is that the credit metric ratio thresholds for the 2018 GCOC proceeding should be higher, in order to account for this increased risk.[926] AltaLink contended that an FFO/debt ratio below the 12.5 per cent absolute minimum of DBRS places it at undue risk and is further evidence that a fair return has not been awarded.[927]

729. AltaLink noted that S&P has not removed the negative trend rating from its regulatory advantage assessment of Alberta that was present during the 2016 GCOC proceeding. Given this negative trend, and the increased uncertainties in its business risk since the 2016 GCOC proceeding, AltaLink submitted that its FFO/debt ratio should be established "in a comfortable range,"[928] in order for it to be able to absorb the financial implications of the business risk uncertainties it faces.[929]

730. AltaLink disagreed with the arbitrary weighting calculations that Mr. Madsen derived for the FFO/debt, FFO interest coverage and EBIT interest coverage ratios. It submitted that the deemed equity ratio cannot be derived from a formula that is based on an unreasonably low FFO/debt ratio.[930]

731. AltaLink commented that the data used by Mr. Madsen and Mr. Bell to derive the inputs for their credit metric calculations was from 2016 and outdated. It submitted that the most current data available, including forecast data, should be used.[931]

732. AltaLink and EPCOR critiqued the credit metric calculations of Mr. Bell. They noted that Mr. Bell used a weighted average for debt, whereas the Commission uses a simple average. They noted that Mr. Bell used a simple average for depreciation, as opposed to the Commission's use of a weighted average. They commented that Mr. Bell did not perform separate calculations for the transmission and distribution utilities, but instead, a combined calculation.[932]

[924] Exhibit 22570-X0767.01, A103.
[925] Exhibit 22570-X0767.01, A109.
[926] Exhibit 22570-X0141, paragraph 32.
[927] Exhibit 22570-X0141, paragraphs 37-38.
[928] Exhibit 22570-X0141, paragraph 35.
[929] Exhibit 22570-X0141, paragraphs 34-35.
[930] Exhibit 22570-X0738, paragraphs 20-21.
[931] Exhibit 22570-X0738, paragraph 33. Exhibit 22570-X0738, paragraph 48.
[932] Exhibit 22570-X0738, paragraphs 44-46. Exhibit 22570-X0733, A34.

### The UCA's comments on credit metrics

733. The UCA opposed Dr. Villadsen's recommendation that the Commission rely on the medial volatility table established by S&P to assess credit metric thresholds. It submitted that Dr. Villadsen has provided no evidence to support her claim that the credit rating agencies no longer view Alberta as possessing a strong regulatory advantage. The UCA recommended that the Commission apply the same credit metric thresholds that were applied in the 2016 GCOC decision.[933]

### The CCA's comments on credit metrics

734. The CCA disagreed with AltaLink's suggestion that forecast values be used to determine the inputs used in a credit metric analysis. It submitted that the use of forecast data adds significant new uncertainty into the credit metric process. The CCA suggested that if forecast data is used, it be should be used uniformly across all the affected utilities.[934]

735. The CCA submitted that the Commission should not factor in the impacts of ACFA funding on a utility's credit metrics in determining the deemed equity ratio in order to maintain a utility's financial integrity.[935]

### Commission findings

736. The Commission will, consistent with its approach in past GCOC decisions, and its findings in Section 9.6, award deemed equity ratios that are, on a stand-alone basis, consistent with credit ratings in the A-range.

737. In this proceeding, parties provided evidence regarding the benchmarks associated with certain credit metrics used by various credit-rating agencies. The Commission acknowledges the submission of Mr. Hevert that credit metrics are only one part of the credit-rating determination process. However, the Commission notes that Mr. Hevert, as well as Dr. Villadsen, Mr. Coyne, Mr. Bell and Mr. Madsen, assessed credit metrics as part of the analysis to determine recommended equity ratios. The Commission is likewise satisfied that formal credit metrics should be considered in the assessment of deemed equity ratios. In doing so, the Commission is cognizant that 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.

738. 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.

933 Exhibit 22570-X0897.01, paragraphs 245-246.
934 Exhibit 22570-X0888, paragraph 346.
935 Exhibit 22570-X0888, paragraph 385.

739. 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 expectations of utility debt and equity investors with respect to credit metric fundamentals. This observation is supported generally by a review of actual market behaviour. The Commission finds that, generally, most utilities in Alberta have had little difficulty raising debt and equity financing on satisfactory terms while maintaining an A-range credit rating.

740. In the 2016 GCOC decision, the Commission placed greater weight on S&P's credit metric benchmarks for FFO coverage and FFO/debt, using a "low volatility scale." No evidence was submitted that this low volatility scale is no longer applicable for the utilities in Alberta. The Alberta regulatory advantage is currently rated by S&P as "strong" with a trend of "negative."[936] This is the same rating that was in place during the 2016 GCOC proceeding. Further support for the continued use of S&P's low volatility scale is the fact that, in Section 9.3 of this decision, the Commission found no significant increase in generic business risk for the affected utilities since the 2016 GCOC proceeding.

741. Dr. Villadsen submitted that the Commission establish a capital structure that is sufficient to meet the credit metric thresholds at the middle of the published guidelines of all the major credit-rating agencies. However, she did not provide the thresholds that are used by Fitch Ratings, and the Commission acknowledged in the 2016 GCOC decision that it is difficult to see how any of the major regulated utilities in Canada could qualify for a credit rating of A from Moody's.[937] The Commission continues to hold this view, especially with respect to the FFO/debt ratio benchmark range of 18 to 26 per cent utilized by Moody's. Consequently, the Commission will not place any reliance on the benchmark ranges of Moody's, nor will the Commission consider Fitch Ratings in its assessment of the affected utilities' credit metrics.

742. The DBRS benchmark ranges for equity ratio, EBIT coverage and FFO coverage were examined during the 2016 GCOC proceeding. In that proceeding, the Commission found evidence that cast doubt on the use of the credit metric benchmark ranges established by DBRS to qualify for an A-range credit rating.[938] No evidence was provided in this GCOC proceeding to satisfactorily eliminate this doubt. Accordingly, the Commission finds the credit metric benchmarks used by DBRS to be less informative than the S&P benchmarks in evaluating the financial parameters necessary for an A-range credit rating.

743. Dr. Villadsen recommended that the Commission target the two FFO-based credit metrics using the point of overlap between S&P's low volatility and medial volatility tables, which would set the FFO interest coverage threshold at 3.0, and the FFO/debt ratio threshold at 13.0. AltaLink contended that a minimum FFO/debt ratio should be 12.5 per cent. The Commission notes that the credit metric analysis it has subsequently prepared, using the approved ROE and deemed equity ratio, shows FFO interest coverage ratios of 3.9 and 3.3 for the distribution and transmission utilities, respectively, and FFO/debt ratios of 13.8 and 11.1 per cent for the distribution and transmission utilities, respectively. Three of these four metrics exceed the thresholds that Dr. Villadsen has recommended.

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[936] Exhibit 22570-X0188.01, PDF page 285.
[937] Decision 20622-D01-2016, paragraph 395.
[938] Decision 20622-D01-2016, paragraph 394.

744. In addition to the three credit metrics the Commission examined in the 2016 GCOC decision, Mr. Coyne calculated the EBITDA coverage and debt/EBITDA ratios in this proceeding. He noted that debt/EBITDA is a core ratio used by S&P, and the benchmark for this ratio, using the low volatility table, is four to five. The Commission calculated the debt/EBITDA ratios resulting from the 2016 GCOC decision credit metric model, and found that while the taxable distribution utilities would have just reached the threshold of five, the non-taxable distribution utilities and both the taxable and non-taxable transmission utilities would not have reached the threshold. This situation remains in the current GCOC proceeding. Considering that the utilities have been able to maintain credit ratings from S&P in the A-range without meeting this credit metric threshold, the Commission considers that meeting the debt/EBITDA ratio is not important, in and of itself. Consequently, the Commission will not focus its attention on the debt/EBITDA credit metric.

745. With respect to the EBITDA coverage ratio, the Commission calculated the results of this ratio resulting from the 2016 GCOC decision credit metric model, and found that both the taxable and non-taxable distribution utilities, as well as the taxable and non-taxable transmission utilities, would have exceeded S&P's medial volatility table benchmark of 2.75. The four ratios were all in excess of 3.1. The same situation remains in the current GCOC proceeding.

746. Mr. Coyne submitted that the credit metrics for the utilities in Alberta are very near the bottom, when compared to the results of his North American electric proxy group. The Commission considers this is mainly because of the higher approved ROEs and deemed equity ratios that the U.S. utilities are awarded. The Commission has discussed the comparability of the U.S. and Canadian regulatory regimes, deemed equity ratios and approved ROEs, in Section 9.3.3, Section 9.3.4 and Section 8.1.

747. Mr. Hevert indicated that changes in the CWIP percentages and the depreciation parameters used in the Commission's credit metric model will affect the FFO/debt ratios. The Commission is aware that changes in these parameters would have an effect on the FFO/debt ratio, and this is one of the reasons the Commission does not target the FFO/debt ratio at the lower end of the threshold. Even if the CWIP and depreciation parameters for the distribution utilities were changed to 10 per cent and five per cent, respectively, the resulting FFO/debt ratio would be 11.8 per cent, which is toward the upper end of S&P's range. If the CWIP and depreciation parameters for the transmission utilities were changed to 10 per cent and 3.8 per cent, respectively, the resulting FFO/debt ratio would be 10 per cent, which is still in excess of the nine per cent threshold established by S&P.

748. Mr. Hevert indicated that S&P makes several adjustments to increase debt balances to reflect debt-like financial obligations, and if these are not reflected in the Commission's credit metric calculations, then the resulting FFO/debt ratio would be overstated. This issue was addressed by the Commission in the 2016 GCOC decision, and the Commission determined that any overstatement is not material.[939] No evidence was brought forward in this proceeding to support a contrary finding.

749. AltaLink contended that an FFO/debt ratio below 12.5 per cent places it at undue risk, and is further evidence that a fair return has not been awarded. The Commission notes that the

[939] Decision 20622-D01-2016, paragraphs 391-392.

12.5 per cent threshold for FFO/debt put forward by AltaLink is from DBRS. The Commission has previously commented that the benchmarks established by DBRS are not as informative as those used by S&P.

750. AltaLink also recommended that the Commission use the most current data available, including forecast data, in calculating credit metrics. The Commission agrees with the CCA that the use of forecast data adds uncertainty into the credit metric process. This is evidenced by the difference in the 2018 forecast CWIP, debt cost and depreciation percentage parameters used by AltaLink in the credit metric calculations included as part of its rebuttal evidence,[940] and those it submitted during the oral hearing.[941] If forecast data was used for AltaLink, the Commission would have to be consistent and use forecast data for all the affected utilities. Forecast data for all the affected utilities, prepared at the same time and for the same years, was not provided. For these reasons, the Commission will continue to base its credit metric analysis on actual data provided through the Rule 005 reports.

751. Dr. Villadsen submitted that it is proper to use the effective income tax rates of the affected utilities, instead of the statutory income tax rates, as part of the credit metric analysis. She indicated that the average effective income tax rate for 2016 for the five utilities that paid income taxes was 8.8 per cent.[942]

752. The Commission notes that the income tax rate does not have any effect on the FFO ratios. In addition, if the Commission uses an income tax rate of 8.8 per cent in its credit metric model, the resulting ratios for the distribution utilities would be an EBIT coverage of 2.1 and EBITDA coverage of 4.0, which are within the Commission's thresholds for an A-range credit rating. Likewise, if an income tax rate of 8.8 per cent for the transmission utilities is used in the Commission's credit metric model, the resulting ratios would be an EBIT coverage of 2.1 and EBITDA coverage of 3.4, which are within the Commission's thresholds for an A-range credit rating. The Commission will continue to analyze credit metrics using an income tax rate of 27 per cent and an income tax rate of zero. Effective income tax rates that are less than the statutory income tax rates will fall somewhere in the range of the results for these two analyses.

753. Mr. Thygesen commented that any credit metric calculations for EPCOR should use the ACFA debt rate, and it should also reflect the exclusion of Westcoast Energy from the comparator group. ACFA debt rates are reflected in the Commission's credit metric analysis, because the average embedded debt rate includes the debt of ENMAX, which is ACFA debt. The Commission will not address the use of Westcoast Energy as a comparator in establishing EPCOR's debt rates for the reasons addressed in Section 7.2, specifically that the Commission is not approving debt rates for EPCOR in this proceeding. This issue is best addressed in a GTA or rebasing proceeding.

754. EPCOR noted that its credit metrics are generally lower than the credit metrics calculated by the Commission for an average distribution and transmission utility. EPCOR stated this is because of its higher debt rates and lower depreciation rates. The Commission has previously stated in Section 7.2 that the City of Edmonton's refusal to make ACFA funding available to EPCOR is reflected in EPCOR's lower credit metrics. The Commission considers that EPCOR's

940 Exhibit 22570-X0738, Table 3.
941 Exhibit 22570-X0858, Table 3.
942 Exhibit 22570-X0767.01, footnote 196.

use of the direct life method for depreciation, and the resulting treatment of salvage, is a contributor to its lower than average depreciation rates. In the decision on EPCOR's 2015 to 2017 transmission GTA, the Commission directed EPCOR to conduct and file research respecting alternative methods of accounting for the cost of removal of retired assets.[943] The Commission will not provide additional credit metric relief to EPCOR on this basis.

755. Mr. Madsen determined base level equity ratios from his credit metric calculations and his estimation of the weighting the Commission placed on the EBIT coverage, FFO coverage and FFO/debt ratios in the 2016 GCOC decision. The Commission agrees with the submissions of Dr. Villadsen and AltaLink that Mr. Madsen's attempt to infer the weightings the Commission placed on these three credit metric ratios in the 2016 GCOC decision was arbitrary, and yielded results that were illogical.

756. Mr. Madsen inferred that for the distribution utilities in the 2016 GCOC decision, the Commission weighted the FFO/debt ratio at 425 per cent, and the EBIT coverage and FFO coverage ratios at negative 163 per cent.[944] There is nothing in the 2016 GCOC decision that would suggest the Commission used any numerical weightings for the three credit ratios.

757. The use of these weightings in determining his deemed equity ratio recommendations leads to results that are not logical. Mr. Madsen's credit metric calculations for ENMAX Distribution showed that in order for it to achieve an A-range credit rating, it required a 39.6 per cent deemed equity ratio. His calculations showed that EPCOR Distribution would require a 30.6 per cent deemed equity ratio in order to achieve an A-range credit rating. This is despite Mr. Madsen's submission that EPCOR Distribution has the worst credit metrics of any utility in Alberta.

758. The Commission notes that, as set out in Table 8, for 2016 ENMAX Distribution's debt cost and CWIP percentages were significantly lower than those of EPCOR Distribution. ENMAX Distribution's depreciation percentage for 2016 was greater than that of EPCOR Distribution. These three differences result in the credit metrics of ENMAX Distribution being better than the credit metrics of EPCOR Distribution. However, based on the use of his inferred weighting results, Mr. Madsen calculated that EPCOR Distribution only required a deemed equity ratio of 30.6 per cent, whereas ENMAX Distribution required a deemed equity ratio of 39.6 per cent. These results are evidence that Mr. Madsen's inferred weightings are not a proper basis upon which to determine a recommended equity ratio.

759. For all the above reasons, the Commission did not find the methodology used by Mr. Madsen to determine his recommended deemed equity ratios helpful, and the Commission has assigned no weight to his deemed equity recommendations.

### 9.7.2 Equity ratios associated with credit metrics

760. In the 2016 GCOC decision (tables 20-23), the Commission provided a sensitivity analysis to illustrate the effect of a range of equity ratios on the three principal credit metrics for the distribution utilities and the transmission utilities, using income tax rates of 27 per cent and

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943 Decision 3539-D01-2015: EPCOR Distribution & Transmission Inc., 2015-2017 Transmission Facility Owner Tariff, Proceeding 3539, Application 1611027-1, October 21, 2015, paragraph 852.

944 Exhibit 22570-X0557, Table 11.

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.

761. The parameter values used by the Commission in the 2016 GCOC decision, as well as the parameter values the Commission has decided to use 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 2016 GCOC decision – taxable distribution utilities | Parameter values applied in 2016 GCOC decision – taxable transmission utilities | Parameter values applied in this decision – taxable distribution utilities | Parameter values applied in this decision – taxable transmission utilities |
|---|---|---|---|---|
| | % | | | |
| Embedded average debt rate | 4.80 | 4.80 | 4.70 | 4.70 |
| ROE | 8.30 | 8.30 | 8.50 | 8.50 |
| Income tax rate | 27.00 | 27.00 | 27.00 | 27.00 |
| Depreciation | 5.75 | 4.10 | 5.85 | 4.20 |
| Construction work in progress | 3.78 | 5.00 | 3.21 | 5.00 |

762. In arriving at the updated parameters, the Commission has reviewed the actual parameters from the 2014 and 2015 Rule 005 filings set out in the 2016 GCOC decision, and the 2016 Rule 005 filings that were submitted as part of this proceeding.

763. 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 affected 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 | | | | |
| 2016 Rule 005 | 2,281,200 | 4.96 | 5.29 | 3.48 |
| 2015 Rule 005 | 2,130,400 | 5.08 | 5.31 | 4.62 |
| 2014 Rule 005 | 1,948,600 | 5.21 | 5.21 | 7.04 |
| FortisAlberta – distribution | | | | |
| 2016 Rule 005 | 2,905,900 | 4.81 | 6.77 | 2.21 |
| 2015 Rule 005 | 2,695,000 | 4.99 | 6.43 | 2.76 |
| 2014 Rule 005 | 2,499,400 | 5.22 | 6.77 | 2.52 |
| ENMAX – distribution | | | | |
| 2016 Rule 005 | 1,177,600 | 3.93 | 5.17 | 1.96 |
| 2015 Rule 005 | 1,093,100 | 4.03 | 5.12 | 2.98 |
| 2014 Rule 005 | 995,900 | 4.24 | 5.06 | 5.09 |
| EPCOR – distribution | | | | |
| 2016 Rule 005 | 987,200 | 5.13 | 4.35 | 3.79 |
| 2015 Rule 005 | 851,000 | 5.00 | 4.30 | 3.57 |
| 2014 Rule 005 | 738,300 | 5.30 | 4.34 | 2.78 |
| ATCO Gas – distribution | | | | |
| 2016 Rule 005 | 2,313,500 | 5.36 | 6.35 | 2.45 |
| 2015 Rule 005 | 2,144,400 | 5.60 | 6.42 | 2.20 |
| 2014 Rule 005 | 1,997,700 | 5.90 | 6.39 | 2.12 |
| AltaGas – distribution | | | | |
| 2016 Rule 005 | 280,500 | 4.54 | 4.90 | 2.39 |
| 2015 Rule 005 | 244,500 | 4.71 | 4.90 | 2.69 |
| 2014 Rule 005 | 215,800 | 4.90 | 5.12 | 1.48 |
| AltaLink – transmission | | | | |
| 2016 Rule 005 | 6,943,100 | 4.00 | 4.58 | 4.71 |
| 2015 Rule 005 | 5,257,400 | 4.11 | 4.50 | 3.49 |
| 2014 Rule 005 | 5,110,500 | 4.10 | 3.37 | -1.20 |
| ATCO Electric – transmission | | | | |
| 2016 Rule 005 | 5,235,700 | 4.77 | 3.59 | 1.44 |
| 2015 Rule 005 | 5,197,900 | 4.72 | 2.67 | 1.40 |
| 2014 Rule 005 | 4,630,200 | 4.84 | 2.83 | 1.54 |
| ENMAX – transmission | | | | |
| 2016 Rule 005 | 424,500 | 3.93 | 3.88 | 6.25 |
| 2015 Rule 005 | 392,200 | 4.03 | 3.86 | 5.82 |
| 2014 Rule 005 | 323,500 | 4.24 | 3.72 | 13.13 |
| EPCOR – transmission | | | | |
| 2016 Rule 005 | 671,900 | 5.22 | 3.54 | 2.52 |
| 2015 Rule 005 | 657,700 | 4.93 | 3.40 | 2.50 |
| 2014 Rule 005 | 624,300 | 4.88 | 3.32 | 3.18 |
| ATCO Pipelines – transmission | | | | |
| 2016 Rule 005 | 1,252,700 | 5.10 | 5.35 | 12.15 |
| 2015 Rule 005 | 1,083,300 | 5.29 | 5.14 | 11.04 |
| 2014 Rule 005 | 956,600 | 5.50 | 5.34 | 8.62 |
| **Simple average** | | | | |
| **2016 Rule 005** | | **4.70** | **4.89** | **3.94** |
| **2015 Rule 005** | | **4.77** | **4.73** | **3.92** |
| **2014 Rule 005** | | **4.94** | **4.68** | **4.21** |

764. 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 | | | |
| 2016 Rule 005 | 4.70 | 4.89 | 3.94 |
| 2015 Rule 005 | 4.77 | 4.73 | 3.92 |
| 2014 Rule 005 | 4.94 | 4.68 | 4.21 |
| Weighted average - overall | | | |
| 2016 Rule 005 | | 4.88 | 3.54 |
| 2015 Rule 005 | | 4.58 | 3.24 |
| 2014 Rule 005 | | 4.39 | 2.35 |
| Simple average – distribution utilities | | | |
| 2016 Rule 005 | 4.79 | 5.47 | 2.71 |
| 2015 Rule 005 | 4.90 | 5.41 | 3.14 |
| 2014 Rule 005 | 5.13 | 5.49 | 3.50 |
| Weighted average – distribution utilities | | | |
| 2016 Rule 005 | | 5.85 | 2.69 |
| 2015 Rule 005 | | 5.77 | 3.16 |
| 2014 Rule 005 | | 5.86 | 3.77 |
| Simple average – transmission utilities | | | |
| 2016 Rule 005 | 4.60 | 4.19 | 5.41 |
| 2015 Rule 005 | 4.62 | 3.91 | 4.85 |
| 2014 Rule 005 | 4.71 | 3.71 | 5.06 |
| Weighted average – transmission utilities | | | |
| 2016 Rule 005 | | 4.22 | 4.12 |
| 2015 Rule 005 | | 3.72 | 3.30 |
| 2014 Rule 005 | | 3.32 | 1.33 |
| Simple average – electric distribution utilities | | | |
| 2016 Rule 005 | 4.71 | 5.39 | 2.86 |
| 2015 Rule 005 | 4.78 | 5.29 | 3.48 |
| 2014 Rule 005 | 4.99 | 5.35 | 4.39 |
| Weighted average – electric distribution utilities | | | |
| 2016 Rule 005 | | 5.73 | 2.78 |
| 2015 Rule 005 | | 5.60 | 3.48 |
| 2014 Rule 005 | | 5.72 | 4.39 |
| Simple average – gas distribution utilities | | | |
| 2016 Rule 005 | 4.95 | 5.62 | 2.42 |
| 2015 Rule 005 | 5.15 | 5.66 | 2.44 |
| 2014 Rule 005 | 5.40 | 5.76 | 1.80 |
| Weighted average – gas distribution utilities | | | |
| 2016 Rule 005 | | 6.19 | 2.45 |
| 2015 Rule 005 | | 6.26 | 2.25 |
| 2014 Rule 005 | | 6.27 | 2.06 |
| Simple average – electric transmission utilities | | | |
| 2016 Rule 005 | 4.48 | 3.90 | 3.73 |
| 2015 Rule 005 | 4.45 | 3.61 | 3.30 |
| 2014 Rule 005 | 4.51 | 3.31 | 4.16 |
| Weighted average – electric transmission utilities | | | |
| 2016 Rule 005 | | 4.12 | 3.36 |
| 2015 Rule 005 | | 3.59 | 2.57 |
| 2014 Rule 005 | | 3.14 | 0.68 |

765. 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**

766. The Commission has applied an ROE value of 8.5 per cent in its credit metric calculations, consistent with its findings in Section 8.8.

**Embedded average debt rate**

767. The simple average of the embedded average debt rates is 4.9 per cent based on the 2014 Rule 005 reports, 4.8 per cent based on the 2015 Rule 005 reports, and 4.7 per cent based on the 2016 Rule 005 reports. These figures demonstrate that the embedded average debt rate is declining, which is to be expected as the affected utilities continue to retire debt with higher interest rates and replace it with lower cost debt.

768. The Commission finds that the use of 4.7 per cent for the embedded average debt rate is reasonable. This figure is between the simple average debt rate for the distribution utilities and the transmission utilities based on the 2016 Rule 005 reports. Given that the affected utilities are expected to continue to retire higher interest debt and replace it with lower interest debt, the Commission considers the use of 4.7 per cent to be conservative.

**Income tax rate**

769. The Commission determined in Section 9.7.1 that it will continue to analyze credit metrics using an income tax rate of 27 per cent. The Commission has also determined credit metrics using an income tax rate of zero, which 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**

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

771. The weighted average depreciation rate as a percentage of invested capital for the distribution utilities based on the 2016 Rule 005 reports is 5.85 per cent, as shown in Table 10. The Commission will use this figure in its credit metric calculations for the distribution utilities. This figure is between the weighted average depreciation rates based on the 2016 Rule 005 reports for the electric distribution utilities (with a figure of 5.73 per cent) and the gas distribution utilities (with a figure of 6.19 per cent).

772. The weighted average depreciation rate as a percentage of invested capital for the transmission utilities based on the 2016 Rule 005 reports is 4.22 per cent, as shown in Table 10. For simplicity and to be conservative, the Commission will round this to 4.2 per cent. This figure is between the weighted average depreciation rate based on the 2016 Rule 005 reports for the electric transmission utilities (with a figure of 4.12 per cent) and the rate for ATCO Pipelines of 5.35 per cent.

### Mid-year CWIP as a percentage of invested capital

773. The overall simple average for the utilities based on the 2014, 2015 and 2016 Rule 005 reports does not provide a clear indication of the trend for this parameter. The percentage decreased from 4.21 using the 2014 Rule 005 report, to 3.92 per cent using the 2015 Rule 005 report. It increased to 3.94 per cent using the 2016 Rule 005 data. The Commission finds the best way to determine this parameter is to use the simple average of the weighted average values for 2014, 2015 and 2016. For the distribution utilities, the result is 3.21 per cent. For the transmission utilities, the result is 2.92 per cent. However, the weighted average percentages for the transmission utilities have increased from 1.33 in 2014, to 3.30 in 2015, to 4.12 per cent in 2016. The Commission finds that in order to reflect this trend, and be conservative, it will continue to use the figure of five per cent that it used in the 2016 GCOC decision for the transmission utilities.

774. 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 2016 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 Table 11, Table 12, Table 13 and Table 14.

**Table 11. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of 27 per cent**

| | EBIT coverage | | FFO coverage | | FFO/debt % | |
|---|---|---|---|---|---|---|
| Equity ratio (%) | 2016 GCOC decision | 2018 | 2016 GCOC decision | 2018 | 2016 GCOC decision | 2018 |
| 30 | 1.9 | 2.0 | 3.3 | 3.4 | 11.3 | 11.6 |
| 31 | 2.0 | 2.0 | 3.4 | 3.5 | 11.6 | 11.9 |
| 32 | 2.0 | 2.1 | 3.4 | 3.6 | 11.9 | 12.2 |
| 33 | 2.1 | 2.2 | 3.5 | 3.6 | 12.2 | 12.5 |
| 34 | 2.1 | 2.2 | 3.6 | 3.7 | 12.5 | 12.8 |
| 35 | 2.2 | 2.3 | 3.6 | 3.8 | 12.6 | 13.2 |
| 36 | 2.2 | 2.3 | 3.7 | 3.8 | 13.2 | 13.5 |
| 37 | 2.3 | 2.4 | 3.8 | 3.9 | 13.5 | 13.8 |
| 38 | 2.4 | 2.4 | 3.8 | 4.0 | 13.8 | 14.2 |
| 39 | 2.4 | 2.5 | 3.9 | 4.1 | 14.2 | 14.6 |
| 40 | 2.5 | 2.6 | 4.0 | 4.1 | 14.6 | 14.9 |
| 41 | 2.5 | 2.6 | 4.1 | 4.2 | 14.9 | 15.3 |
| 42 | 2.6 | 2.7 | 4.2 | 4.3 | 15.3 | 15.7 |
| 43 | 2.7 | 2.8 | 4.2 | 4.4 | 15.8 | 16.2 |
| 44 | 2.8 | 2.9 | 4.3 | 4.5 | 16.2 | 16.6 |
| 45 | 2.8 | 2.9 | 4.4 | 4.6 | 16.6 | 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 (%) | 2016 GCOC decision, non-taxable | 2018 non-taxable | 2016 GCOC decision, non-taxable | 2018 non-taxable | 2016 GCOC decision, non-taxable | 2018 non-taxable |
| 30 | 1.7 | 1.7 | 3.3 | 3.4 | 11.3 | 11.6 |
| 31 | 1.7 | 1.8 | 3.4 | 3.5 | 11.6 | 11.9 |
| 32 | 1.7 | 1.8 | 3.4 | 3.6 | 11.9 | 12.2 |
| 33 | 1.8 | 1.8 | 3.5 | 3.6 | 12.2 | 12.5 |
| 34 | 1.8 | 1.9 | 3.6 | 3.8 | 12.5 | 12.8 |
| 35 | 1.9 | 1.9 | 3.6 | 3.6 | 12.8 | 13.2 |
| 36 | 1.9 | 2.0 | 3.7 | 3.8 | 13.2 | 13.5 |
| 37 | 1.9 | 2.0 | 3.8 | 3.9 | 13.5 | 13.8 |
| 38 | 2.0 | 2.0 | 3.8 | 4.0 | 13.8 | 14.2 |
| 39 | 2.0 | 2.1 | 3.9 | 4.1 | 14.2 | 14.6 |
| 40 | 2.1 | 2.1 | 4.0 | 4.1 | 14.6 | 14.9 |
| 41 | 2.1 | 2.2 | 4.1 | 4.2 | 14.9 | 15.3 |
| 42 | 2.2 | 2.2 | 4.2 | 4.3 | 15.3 | 15.7 |
| 43 | 2.2 | 2.3 | 4.2 | 4.4 | 15.8 | 16.2 |
| 44 | 2.3 | 2.3 | 4.3 | 4.5 | 16.2 | 16.6 |
| 45 | 2.3 | 2.4 | 4.4 | 4.6 | 16.6 | 17.0 |

**Table 13. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of 27 per cent**

| | EBIT coverage | | FFO coverage | | FFO/debt % | |
|---|---|---|---|---|---|---|
| Equity ratio (%) | 2016 GCOC decision | 2018 | 2016 GCOC decision | 2018 | 2016 GCOC decision | 2018 |
| 30 | 1.9 | 2.0 | 2.8 | 2.9 | 9.0 | 9.2 |
| 31 | 2.0 | 2.0 | 2.9 | 3.0 | 9.2 | 9.4 |
| 32 | 2.0 | 2.1 | 2.9 | 3.0 | 9.5 | 9.7 |
| 33 | 2.1 | 2.1 | 3.0 | 3.1 | 9.7 | 10.0 |
| 34 | 2.1 | 2.2 | 3.0 | 3.1 | 10.0 | 10.2 |
| 35 | 2.2 | 2.2 | 3.1 | 3.2 | 10.3 | 10.5 |
| 36 | 2.2 | 2.3 | 3.1 | 3.3 | 10.5 | 10.8 |
| 37 | 2.3 | 2.3 | 3.2 | 3.3 | 10.8 | 11.1 |
| 38 | 2.3 | 2.4 | 3.3 | 3.4 | 11.1 | 11.4 |
| 39 | 2.4 | 2.5 | 3.3 | 3.4 | 11.5 | 11.7 |
| 40 | 2.5 | 2.5 | 3.4 | 3.5 | 11.8 | 12.1 |
| 41 | 2.5 | 2.6 | 3.5 | 3.6 | 12.1 | 12.4 |
| 42 | 2.6 | 2.7 | 3.5 | 3.7 | 12.5 | 12.8 |
| 43 | 2.7 | 2.7 | 3.6 | 3.7 | 12.8 | 13.1 |
| 44 | 2.7 | 2.8 | 3.7 | 3.8 | 13.2 | 13.5 |
| 45 | 2.8 | 2.9 | 3.8 | 3.9 | 13.6 | 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 (%) | 2016 GCOC decision, non-taxable | 2018 non-taxable | 2016 GCOC decision, non-taxable | 2018 non-taxable | 2016 GCOC decision, non-taxable | 2018 non-taxable |
| 30 | 1.7 | 1.7 | 2.8 | 2.9 | 9.0 | 9.2 |
| 31 | 1.7 | 1.7 | 2.9 | 3.0 | 9.2 | 9.4 |
| 32 | 1.7 | 1.8 | 2.9 | 3.0 | 9.5 | 9.7 |
| 33 | 1.8 | 1.8 | 3.0 | 3.1 | 9.7 | 10.0 |
| 34 | 1.8 | 1.8 | 3.0 | 3.1 | 10.0 | 10.2 |
| 35 | 1.8 | 1.9 | 3.1 | 3.2 | 10.3 | 10.5 |
| 36 | 1.9 | 1.9 | 3.1 | 3.3 | 10.5 | 10.8 |
| 37 | 1.9 | 2.0 | 3.2 | 3.3 | 10.8 | 11.1 |
| 38 | 2.0 | 2.0 | 3.3 | 3.4 | 11.1 | 11.4 |
| 39 | 2.0 | 2.1 | 3.3 | 3.4 | 11.5 | 11.7 |
| 40 | 2.1 | 2.1 | 3.4 | 3.5 | 11.8 | 12.1 |
| 41 | 2.1 | 2.1 | 3.5 | 3.6 | 12.1 | 12.4 |
| 42 | 2.1 | 2.2 | 3.5 | 3.7 | 12.5 | 12.8 |
| 43 | 2.2 | 2.3 | 3.6 | 3.7 | 12.8 | 13.1 |
| 44 | 2.2 | 2.3 | 3.7 | 3.8 | 13.2 | 13.5 |
| 45 | 2.3 | 2.4 | 3.8 | 3.9 | 13.6 | 13.9 |

775. The Commission has undertaken the above calculations in light of the credit metric findings in Section 9.7.1. The Commission observes that the credit rating metrics required for an Alberta utility to achieve a credit rating in the A-range have not changed since the 2016 GCOC decision. Table 15 sets out the guidelines established by the Commission in this section to achieve a credit rating in the A-range, which assumes a credit rating assessment of "strong" for the Alberta regulatory environment. The guidelines do not take into account potential adjustments to the 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.

776. Table 15 sets out the minimum equity ratio that would be required, in conjunction with an approved ROE of 8.5 per cent, for distribution and transmission utilities in Alberta with an income tax rate of 27 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 2018 GCOC proceeding that has an income tax rate of 27 per cent, would require a deemed equity ratio of 30 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 35 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 |
|---|---|---|---|---|---|
| | | | (%) | | |
| 2016 distribution utilities – 27 per cent income tax rate | 31 | Below 30 | Below 30 | Below 30 | 36 |
| 2018 distribution utilities – 27 per cent income tax rate | 30 | Below 30 | Below 30 | Below 30 | 35 |
| | | | | | |
| 2016 distribution utilities – zero per cent income tax rate | 38 | Below 30 | Below 30 | Below 30 | 36 |
| 2018 distribution utilities – zero per cent income tax rate | 36 | Below 30 | Below 30 | Below 30 | 35 |
| | | | | | |
| 2016 transmission utilities – 27 per cent income tax rate | 31 | Below 30 | 33 | 30 | 44 |
| 2018 transmission utilities – 27 per cent income tax rate | 30 | Below 30 | 31 | 30 | 43 |
| | | | | | |
| 2016 transmission utilities – zero per cent income tax rate | 38 | Below 30 | 33 | 30 | 44 |
| 2018 transmission utilities – zero per cent income tax rate | 37 | Below 30 | 31 | 30 | 43 |

777. Based on the results of its credit metric calculations, the Commission continues to find, as it did in the 2016 GCOC decision, "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."[945]

## 9.8 Business risk utility sector analysis

778. In the 2016 GCOC decision, the Commission expressed the following view with respect to how it accounted for any differences between the Alberta transmission and distribution utilities as part of its determination of the deemed equity ratios:

> … the Commission notes that its credit metric calculations do not support the continuation of a 400 bps difference in the awarded deemed equity ratios based on financial risk. It is also unclear that a difference of any amount remains warranted using only a credit metric financial risk analysis. From a business risk perspective, the Commission agrees that there are differences in rate regulation (for example: PBR versus cost-of-service rate regulation) and depreciation rate differences between transmission and distribution utilities, and other business risk differences, such as the method of recovery of fixed costs, although this is somewhat mitigated for the gas distribution utilities under PBR which accounts for actual changes in customer usage. Accordingly, the Commission will balance the financial risks as examined in the credit metric calculations and business risks including utility sector business risks, in arriving at its final deemed equity ratio determinations.[946]

945 Decision 20622-D01-2016, paragraph 433.
946 Decision 20622-D01-2016, paragraph 533.

779. In this proceeding, the Commission asked each of Dr. Carpenter, Dr. Villadsen, Mr. Buttke, Mr. Coyne, Mr. Hevert, Mr. Johnson, Mr. Madsen, Mr. Bell and Dr. Cleary to provide their respective views on the relative riskiness of the Alberta transmission and distribution utilities.

780. Dr. Carpenter commented that there is insufficient data or granularity in order to make distinctions between the relative riskiness, and did not object to the Commission's decision in 2016 to grant deemed equity ratios that were essentially equivalent for all the Alberta utilities, with the exception of ENMAX and AltaGas.[947] Dr. Villadsen concurred with Dr. Carpenter, and Mr. Buttke did not offer an opinion.[948]

781. Dr. Villadsen recommended that the relative deemed equity ratios from the 2016 GCOC decision stay in place, because nothing in her analysis suggests that the criteria used to determine the relative deemed equity ratios of the distribution and transmission utilities has changed since the 2016 GCOC decision.[949]

782. Mr. Coyne expressed the view that Alberta transmission and distribution utilities are essentially the same, and he did not distinguish between them on a risk basis when determining his recommended deemed equity ratio.[950]

783. Mr. Hevert stated that while he would not necessarily disagree with the Commission's previous recognition of somewhat more risk associated with the distribution utilities, he did recommend the same deemed equity ratio for the Alberta transmission and distribution utilities as part of this proceeding.[951]

784. Mr. Johnson indicated that, on average, the Alberta transmission and distribution utilities have essentially the same risk. He stated that within the Alberta distribution utilities, ATCO Gas is less risky.[952] Mr. Madsen considered that the risk profile of the distribution utilities has decreased relative to the risk profile of the transmission utilities in the last number of years.[953]

785. Mr. Bell stated he does not see the Alberta transmission and distribution utilities as materially different. Dr. Cleary indicated that based on his quantitative analysis of the CV (EBIT/sales), the differences in business risk between the Alberta transmission and distribution utilities are not as pronounced as argued in previous proceedings.[954]

### Commission findings

786. In this decision, the Commission will balance the financial risks as examined in the credit metric calculations, and its analysis of business risks, including utility sector business risks, in arriving at its final deemed equity ratio determinations. The Commission notes that no parties

947 Transcript, Volume 4, pages 696-697.
948 Transcript, Volume 4, pages 697-698.
949 Exhibit 22570-X0193.01, A92.
950 Transcript, Volume 5, pages 980-981.
951 Transcript, Volume 6, pages 1251-1252.
952 Transcript, Volume 7, pages 1347-1348.
953 Exhibit 22570-X0701.01, CCA-AUC-2018JAN26-014.
954 Transcript, Volume 10, pages 2157-2159.

identified any significant business risks differences between the distribution utilities and the transmission utilities that would justify different deemed equity ratios for the two sectors.

### 9.9 Equity ratio adjustments for income-tax-exempt or non-taxable utilities

787. Mr. Coyne stated that it is necessary to add at least 200 bps to the deemed equity ratio of a non-taxable utility to achieve the same level of equity return that is approved for taxable utilities. He submitted this will provide the non-taxable utilities compensation for the additional risk they bear relative to the taxable utilities. Mr. Coyne submitted that denying this 200 bps adder effectively awards a higher return to taxable utilities for what is otherwise the same level of risk. He stated that this violates the comparability principle of the fair return standard.[955]

788. Mr. Coyne recommended a 42 per cent deemed equity ratio for non-taxable utilities.[956] He submitted that the non-taxable utilities require higher deemed equity ratios to achieve the same credit metrics as the taxable utilities.[957]

789. Mr. Coyne indicated that a taxable utility holds a cash-flow advantage over a non-taxable utility, because it receives recovery of income tax expense in its revenue requirement. He submitted that the regulatory benefits arising from income tax recovery could be equalized by adjusting the deemed equity ratios such that taxable and non-taxable utilities achieve the same credit metrics.[958]

790. Mr. Coyne submitted that while taxable utilities in Alberta bear very little risk for their exposure to income taxes, they realize significant financial benefits. He referred to Mr. Bell's submission that non-taxable utilities do not have the income tax shield that is available to taxable utilities to cushion the after-tax impact of changes in deductible costs. Mr. Coyne explained that if the O&M expenses of a taxable utility increase above the approved amount then, all else equal, the income taxes decrease. This is not the case for non-taxable utilities. Mr. Coyne submitted this discrepancy should be reflected in a higher equity ratio for non-taxable utilities.[959]

791. Mr. Madsen argued that the 200 bps increase requested by ENMAX as an income-tax-exempt utility is not required to support credit metrics for 2018 to 2020. He stated this is no different than other forms of credit metric relief, and it should only be provided if it is necessary for the utility to maintain a credit rating in the A-range, after all other non-equity based credit metric relief measures have been implemented.[960] The CCA agreed with Mr. Madsen's submissions.[961]

#### Commission findings

792. The Commission addressed this issue in the 2016 GCOC decision, and determined that a 200 bps adder to the deemed equity ratios for income-tax-exempt or non-taxable utilities was not warranted. In this proceeding, Mr. Coyne did not distinguish between income-tax-exempt utilities, such as ENMAX and EPCOR, and non-taxable utilities, which could apply to utilities

955 Exhibit 22570-X0131, PDF pages 105-106.
956 Exhibit 22570-X0131, PDF page 106.
957 Exhibit 22570-X0131, PDF pages 101-102.
958 Exhibit 22570-X0131, PDF pages 105-106.
959 Exhibit 22570-X0775, PDF pages 61-62.
960 Exhibit 22570-X0557, paragraphs 114-115.
961 Exhibit 22570-X0888, paragraph 470.

that are required to pay income taxes, but currently have no taxable income. The Commission considers that because Mr. Coyne presented evidence on behalf of ENMAX, his recommendation for a 200 bps adder applies to the income-tax-exempt utilities.

793. Mr. Coyne submitted that there is a difference in credit metrics between the income-tax-exempt utilities and the taxable utilities, and the addition of a 200 bps adder to the deemed equity ratio of the income-tax-exempt utilities would alleviate this problem. The Commission notes that the FFO/debt and the FFO coverage ratios are not affected by income tax status, whereas the EBIT coverage, EBITDA coverage and debt/EBITDA ratios are. In the 2016 GCOC decision, the Commission agreed with parties that the most important credit ratio to focus on was the FFO/debt ratio.[962] No evidence was submitted in this proceeding that would alter the Commission's view on this matter. Therefore, the Commission remains of the view that the most important credit metric to focus on is the FFO/debt ratio.

794. As part of its credit metric analysis in Section 9.7.2, the Commission looked at the credit metrics that would be achieved by income-tax-exempt distribution utilities and income-tax-exempt transmission utilities. The Commission agrees that there are differences between the taxable utilities and the income-tax-exempt utilities with respect to the EBIT/coverage and EBITDA coverage ratios. However, the Commission notes that at a deemed equity ratio of 37 per cent, the EBIT coverage and EBITDA coverage ratios for income-tax-exempt distribution utilities of 2.0 and 3.9, respectively, are within the applicable A-range thresholds for DBRS and S&P. The Commission also notes that at a deemed equity ratio of 37 per cent, the EBIT coverage and EBITDA coverage ratios for income-tax-exempt transmission utilities of 2.0 and 3.3, respectively, are within the A-range thresholds for DBRS and S&P.

795. Mr. Coyne submitted that denying the 200 bps adder awards a relatively higher return to taxable utilities for what is otherwise the same level of risk. He based this on his judgment that the taxable utilities in Alberta bear very little risk for their exposure to income taxes. The Commission disagrees with Mr. Coyne that the taxable utilities in Alberta bear very little risk for their exposure to income taxes.

796. As described in Section 5.4, every one of the taxable utilities has requested that one or more deferral accounts be established for a variety of aspects regarding income tax. These range from changes in statutory income tax rates and capital cost allowance rates, to protection against income tax reassessments, to material amendments to income tax legislation. The Commission considers that if the taxable utilities perceived very little risk relating to income taxes, they would not be requesting these deferral accounts. The Commission finds that there are business risks related to income tax that are faced by the taxable utilities, and not faced by the income-tax-exempt utilities. This difference in business risk must be considered when assessing the disadvantage the income-tax-exempt utilities have in the area of certain credit metrics.

797. Mr. Coyne and Mr. Bell discussed the income tax shield that is available to taxable utilities. Mr. Coyne explained that if operating expenses for a taxable utility increase above the approved amount then, all else equal, the income taxes decrease. The Commission agrees with this statement, but it notes that the reverse situation applies as well. If the operating expenses of a taxable utility decrease below the approved amount then, all else equal, the income taxes

[962] Decision 20622-D01-2016, paragraph 563.

increase. Any operating expense savings for an income-tax-exempt utility flow through 100 per cent to net income.

798. Based on the foregoing, the Commission finds that a 200 bps adder to the deemed equity ratio for the income-tax-exempt utilities is not warranted.

### 9.10 Equity ratio adjustments for ENMAX

799. In this section, the Commission will review the business risk evidence for ENMAX.

800. Mr. Coyne noted that the deemed equity ratio for ENMAX Distribution in 2015 was 40 per cent, and dropped to 36 per cent for 2017. He submitted that in the 2016 GCOC decision, the Commission cited no substantive change in the risk of ENMAX Distribution that would warrant such a dramatic reduction.[963]

801. Mr. Coyne reviewed the business risk profile of ENMAX. Based on his review, he stated there are material differences between ENMAX and the average Alberta utility, but his belief is that these differences do not warrant an explicit adjustment from the approved ROE and deemed equity ratio he recommended for the income-tax-exempt utilities in Alberta. He submitted there is nothing to suggest that ENMAX should be considered to be lower risk than the other utilities in Alberta, and indeed ENMAX has higher risk in many respects.[964]

#### Commission findings

802. The Commission set out its reasons for establishing the current deemed equity ratio for ENMAX in the 2016 GCOC decision, and in Decision 22211-D01-2017. The main reason for the 300 bps reduction in ENMAX Distribution's deemed equity ratio approved on an interim basis in the 2016 GCOC decision was the elimination of the 200 bps adder that had been previously awarded because of ENMAX's income-tax-exempt status. The reason for the 100 bps reduction in Decision 22211-D01-2017 was the deviation between ENMAX's actual equity ratios and its deemed equity ratios, and its apparent ability to operate at a significantly lower year-end equity ratio without impairment to its ongoing operations, its financial integrity or its ability to raise capital.[965]

803. The Commission acknowledges the submission of Mr. Coyne that ENMAX has committed to maintaining an actual equity ratio that is consistent with its deemed equity ratio. In reviewing the 2016 Rule 005 reports for ENMAX Transmission and ENMAX Distribution, the Commission notes that the actual year-end ratio for both was 37 per cent.[966] The Commission agrees with Mr. Coyne that there is nothing to suggest that ENMAX should be considered lower risk than the other utilities in Alberta. Therefore, the Commission finds that the deemed equity ratio for ENMAX should be the same as the other affected utilities, with the exception of AltaGas.

963 Exhibit 22570-X0131, PDF page 84.
964 Exhibit 22570-X0131, PDF page 109.
965 Decision 22211-D01-2017, paragraphs 79-80.
966 Exhibit 22570-X0139, worksheet 2.2 TT. Exhibit 22570-X0138, worksheet 2.2 DT.

### 9.11 Determination of Commission-approved deemed equity ratios

804. In this section on capital structure, the Commission started with a review of generic business risks. This included an overall assessment of the business risks of the affected utilities, in Section 9.3.1. The Commission considered that the favourable financial performance of the affected utilities over the 2005 to 2016 period is support for assessing the utilities in Alberta as having low financial risk.

805. The generic business risk review continued in Section 9.3.2. There, the Commission looked at the specific issues identified by the utilities that, in their submission, have increased their regulatory risk since the 2016 GCOC decision. These issues were (1) the 2018 to 2022 PBR term; (2) the Commission's UAD decision and the related issue of asset utilization; (3) the increase in customer contributions; (4) regulatory lag; and (5) clean energy initiatives. The Commission found no increase in business risk since the 2016 GCOC decision as a consequence of any of these five specific issues.

806. In Section 9.3.3, the Commission reviewed the submissions on the business risk comparisons between the affected utilities and utilities in other jurisdictions, primarily in the U.S. The Commission found no persuasive evidentiary support for the conclusion that regulatory risk in the U.S. is less than that for utilities in Alberta.

807. The Commission examined evidence comparing the deemed equity ratios it awards to the deemed equity ratios awarded in other jurisdictions in Section 9.3.4 and found there are reasons why the deemed equity ratios awarded in Alberta cannot be compared to those awarded by U.S. regulators. The Commission also found that the deemed equity ratio it awarded in the 2016 GCOC decision is comparable to those in other Canadian jurisdictions.

808. In Section 9.4, the Commission considered the submissions from Mr. Hevert regarding industry financing practices, and then reviewed the submissions of FortisAlberta regarding equity attraction. The Commission found that the utilities will always face some refinancing risks, and assessing long-term refinancing risk for the utilities in Alberta will involve long-term assumptions about bond markets, which could change substantially over the ensuing years.

809. The Commission further addressed the considerations brought forward by FortisAlberta on equity attraction in Section 9.5. Among other findings, the Commission considered that FortisAlberta's equity investor would likely assess not only the approved ROE but also the actual ROEs that have been achieved by FortisAlberta, which averaged 10.2 per cent over the years 2010 to 2016.

810. The Commission's analysis of financial risk, focusing on the credit metrics required to achieve an A-range credit rating, is set out in Section 9.7.

811. Based on the information in Table 11 and Table 13, the Commission notes that an average distribution utility and an average transmission utility, with an income tax rate of 27 per cent, would meet all the credit metric guidelines of the Commission, with an ROE of 8.5 per cent, at a deemed equity ratio of 30 per cent. An average distribution and transmission utility that is either income-tax-exempt or currently non-taxable, would meet the FFO/debt and FFO coverage credit metric guidelines of the Commission, with an ROE of 8.5 per cent, at a deemed equity ratio of 30 per cent. The Commission's EBIT coverage credit metric guideline would be met with a 36 per cent deemed equity ratio at an ROE of 8.5 per cent for those distribution

utilities that have no income tax expense, and with a 37 deemed equity ratio for the transmission utilities that have no income tax expense.

812. In Section 9.8, the Commission examined whether there are business risk differences between the distribution utilities and the transmission utilities that would warrant different deemed equity ratios. The Commission concluded that no such finding is warranted.

813. In Section 9.9, the Commission reviewed the recommendation of Mr. Coyne that the income-tax-exempt utilities should receive a 200 bps adder to their deemed equity ratio. . Based on its findings in that section, the Commission determined that no adder was warranted.

814. Finally, in Section 9.10, the Commission examined the submissions regarding the deemed equity ratio for ENMAX. Based on its review of the evidence, the Commission found that the deemed equity ratio for ENMAX should be the same as for the other utilities in Alberta, with the exception of AltaGas.

815. Considering all the information and findings set out in this capital structure section, the Commission finds that no change is required to the deemed equity ratio set out in the 2016 GCOC decision, with the exception of the deemed equity ratio for ENMAX, as discussed in Section 9.10, and the deemed equity ratio of AltaGas, which will be addressed in the following section. The Commission has determined that a deemed equity ratio of 37 per cent for both distribution and transmission utilities, with the exception of AltaGas, 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 an 8.5 per cent approved ROE for 2018 to 2020, and will enable the affected utilities to maintain a credit rating in the A-range.

# 10 Determination of Commission-approved deemed equity ratio for AltaGas Utilities Inc.

816. In this section, the Commission will determine the deemed equity ratio for AltaGas, considering the determinations previously made in this decision, as well as the evidence regarding the business risk of AltaGas and the submissions regarding the actual credit rating of AltaGas.

## Business risk

817. AltaGas submitted that its business risk is higher than the benchmark Alberta utility, which has been recognized in previous GCOC decisions. It indicated that the previously awarded 400 bps adder continues to be appropriate to reflect its relative risk to the benchmark Alberta utility. AltaGas stated that this is supported by (1) its size and geographically dispersed system; (2) its gas supply risk; (3) the support of all parties in the proceeding; (4) previous Commission decisions; and (5) the application of the stand-alone principle.[967]

818. Dr. Carpenter submitted that the 400 bps adder to the deemed equity ratio for AltaGas be maintained.[968] He indicated that AltaGas faces unusual supply risk because of the risk that some of the older lateral supply pipelines it uses but does not own may be shut in. This will require

[967] Exhibit 22570-X0898, paragraphs 4-5.
[968] Exhibit 22570-X0131, A6.

AltaGas to either obtain alternative supplies, or take on financial responsibility for owning and/or maintaining these old lateral supply pipelines. He added that if the utility has to take on responsibility for the aging supply infrastructure, this could also elevate the operating risk for AltaGas. Dr. Carpenter stated that these supply risks are significant for AltaGas, because of its small size and dispersed service territory.[969]

### Actual credit rating

819. In a letter dated January 24, 2018, the Commission invited parties to comment on an issue that had arisen in Proceeding 23010: AltaGas Utility Group Inc. – Application for the Sale and Transfer of Capital Stock. In that letter, the Commission articulated the issue as follows: "Should a utility incapable of raising debt at an A rating receive a deemed equity ratio and deemed return on equity premised upon an A credit rating?"[970]

820. The Commission issued Decision 23010-D01-2018[971] on January 30, 2018, in which it noted the following:

> 33. The Commission in an IR raised the issue of an apparent disconnect between the equity thickness the Commission awarded AltaGas Utilities based on a credit rating of A category in the GCOC decisions and the cost of debt that is flowed to its customers based on an investment grade credit rating of BBB of AltaGas Ltd. AltaGas Group, in its response stated:
>
>> AUI's current rates reflect the interest rates on the debt that was present during the 2012 test year as adjusted in compliance filing, and further adjusted for the effects of the PBR formula and capital tracker proceedings during the years 2013-2017.
>>
>> …
>>
>> It is important to note, that the 2016 GCOC Decision did not direct AUI, or any Alberta utility, to modify its interest expense from those approved within the first generation PBR Decision 2012-237. AUI customers are paying rates that are fully reflective of past Commission decisions – including equity ratio and ROE as determined by the Commission in its GCOC proceedings and debt rates tested separately by the Commission for prudence.
>
> 34. AltaGas expressed its view that any relationship between a utility's actual credit rating and the resulting cost of debt on one hand, and the findings in the Commission's GCOC decisions regarding the allowed ROE and equity thickness awarded to the utility based on an A category credit rating on the other hand, requires a wider forum. The Commission agrees and considers the 2018 GCOC proceeding to be the correct forum to address this issue. [footnotes omitted][972]

821. AltaGas submitted that the Commission has already addressed the issue articulated in the January 24, 2018 letter, through the robust ratemaking principles and processes that have been established over the last decade or more. It commented that the Commission has adopted

969 Exhibit 22570-X0186, A14-A15.
970 Exhibit 22570-X0616.
971 Decision 23010-D01-2018: AltaGas Utility Group Inc., Application for the Sale and Transfer of Capital Stock, Proceeding 23020, January 30, 2018.
972 Decision 23010-D01-2018, paragraphs 33-34.

principles to ensure that customers of a particular utility only pay debt costs that are deemed as prudent. AltaGas pointed out that in its decision on AltaGas's 2010-2012 general rate application (GRA),[973] the Commission reduced AltaGas's allowed cost of debt rate on two debentures, based on a prudency review.[974]

822. AltaGas submitted that the Commission has, and can continue to, address any issues associated with the cost of debt, including the issue identified by the Commission in its January 24, 2018 letter, through a prudency review in a general rate case, rather than through changes to capital structure.[975] For the PBR utilities, AltaGas indicated this prudence review takes place in a rebasing proceeding for going-in rates.[976] AltaGas noted that it's going-in debt costs for the 2018-2022 PBR term reflect an average embedded rate of 4.46 per cent. It indicated that it will bear the incremental cost for any debt it issues during the 2018-2022 PBR term at rates in excess of 4.46 per cent. AltaGas stated that in the next PBR rebasing proceeding, the Commission will determine the prudency of any debt issuances made by AltaGas during the 2018-2022 PBR term.[977]

823. Following its consideration of all the submissions made by parties in response to its January 24, 2018 letter, the Commission advised the parties on February 9, 2018 as follows:

> 6. The Commission agrees with the submissions of Fortis, AltaLink, EPCOR and the ATCO Utilities that the specific issue raised in the Commission's letter of January 24, 2018, currently relates only to AltaGas and does not need to be considered in the 2018 GCOC proceeding for other companies. However, the Commission will address the issue as it relates to AltaGas's deemed equity ratio and return on equity to be approved in this proceeding, and considers that this is within the existing scope of the proceeding.
>
> 7. Further, the Commission notes that the specific issue identified in relation to AltaGas may also be considered, in part, in the context of the Commission's practice of maintaining credit ratings in the A category for the utilities in Alberta. This matter was explored by the Commission in interrogatories and may be explored further during the oral hearing.[978]

824. In argument, AltaGas submitted its customers are not harmed by its current debt practices, because they pay for debt at rates that have been determined to be prudent by the Commission.[979] AltaGas considered that the evidence of Dr. Carpenter and Dr. Villadsen regarding the fair return standard is relevant in addressing this issue.[980] AltaGas stated that the Commission has historically acknowledged and considered, in past GCOC decisions, AltaGas's access to BBB-rated debt and its unique business risks when deciding a fair return and

973 Decision 2012-091: AltaGas Utilities Inc., 2010-2012 General Rate Application – Phase I, Proceeding 904, Application 1606694-1, April 9, 2012.
974 Exhibit 22570-X0652, PDF page 1.
975 Exhibit 22570-X0652, PDF page 2. Exhibit 22570-X0783, paragraph 51.
976 Exhibit 22570-X0652, PDF page 2.
977 Exhibit 22570-X0652, PDF page 2.
978 Exhibit 22570-X0658, paragraphs 6-7.
979 Exhibit 22570-X0921, paragraph 11.
980 Exhibit 22570-X0783, paragraph 49.

establishing a deemed equity ratio for AltaGas. It added that its cost of debt has historically been addressed for prudence in its GRAs and annual capital tracker true up applications.[981]

825. The CCA submitted that the Commission must determine whether it remains in the public interest to continue to target an A-range credit rating for AltaGas considering the associated cost of doing so and that the benefit of reduced debt costs is not received.[982]

826. Dr. Cleary described the situation that is occurring with AltaGas as not desirable. He indicated that customers are bearing the additional cost of the deemed equity ratio increase to maintain the A-range credit rating, and customers are paying the higher interest rates associated with a sub-A credit rating. He commented that AltaGas is being rewarded for not being able to maintain the company's financial health.[983]

827. Mr. Bell stated that it is incumbent upon the Commission to ensure that AltaGas's rates only include the cost of debt that would be attributable to an A-range credit rating, and that there must be symmetry.[984]

828. AltaGas commented that any credit metric analysis that targets an A-range credit rating does not guarantee an A-range credit rating for any particular utility. It noted this is the case in its situation, especially when its debenture issues are small. AltaGas stated that its embedded cost of debt is in the middle of the range for the Alberta utilities.[985] This observation was shared by Dr. Villadsen.[986]

829. AltaGas submitted that the fair return standard, comprised of the deemed equity ratio and the approved ROE, should not be conflated with the cost of debt. It suggested that while credit metrics provide a useful baseline for assessing the deemed equity ratio, business risks must also be assessed to ensure the fair return standard is met. AltaGas stated its business risks have not declined.[987]

830. AltaGas stated that if the Commission still views this issue as being outstanding, it requests an opportunity to address the merits of any outstanding matter in a proper, considered and procedurally fair manner.[988]

### Commission findings

831. As a preliminary matter, the Commission rejects AltaGas's submission that the issue articulated in the Commission's January 24, 2018 letter has already been addressed.

832. AltaGas stated that in prior GCOC and GRA decisions, the Commission and its predecessor have historically acknowledged and considered AltaGas's access to BBB-rated debt and its unique business risks when deciding a fair return and establishing a deemed equity ratio

981 Exhibit 22570-X0848, PDF pages 1-2.
982 Exhibit 22570-X0888, paragraph 299.
983 Exhibit 22570-X0675, UCA-AUC-2018JAN26-005.
984 Transcript, Volume 10, page 2160.
985 Exhibit 22570-X0898, paragraphs 38-39.
986 Transcript, Volume 3, page 544.
987 Exhibit 22570-X0898, paragraphs 43-44.
988 Exhibit 22570-X0921, paragraph 21.

for AltaGas.[989] Further, AltaGas indicated that its cost of debt has historically been addressed for prudence, separate and apart from ROE and capital structure matters, in AltaGas's GRAs. Accordingly, AltaGas submitted that its access to BBB-rated debt and its unique business risks have already been accounted for in determining a fair return for AltaGas.

833. The level of AltaGas's debt costs is not new. However, the issue before the Commission in this proceeding is whether the Commission should continue to establish a deemed equity ratio for AltaGas that, when combined with the approved ROE, will achieve target credit ratings in the A-range, given that AltaGas's customers do not receive the benefit of debt financing obtained at A-range credit-rating levels. This issue was highlighted in Proceeding 23010, and is one that the Commission is satisfied has not been specifically examined in any prior proceeding that addressed AltaGas's cost of capital.

834. The Commission also rejects AltaGas's contention that, if the Commission still views this issue as outstanding, AltaGas should be afforded a further opportunity to address the merits of the matter in a proper, considered and procedurally fair manner before any changes are made to AltaGas's capital structure. The inability of AltaGas to obtain debt at A-range credit-rating levels was specifically identified as an issue in this proceeding in the Commission's January 24, 2018 letter, following Proceeding 23010. In that proceeding, AltaGas stated that this issue was best addressed in a forum other than Proceeding 23010.[990]

835. In subsequent correspondence issued in this proceeding on February 9, 2018, the Commission expressly stated that it would "address the issue as it relates to AltaGas's deemed equity ratio and return on equity to be approved in this proceeding, and considers that this is within the existing scope of the proceeding."[991] It added, "Further, the Commission notes that the specific issue identified in relation to AltaGas may also be considered, in part, in the context of the Commission's practice of maintaining credit ratings in the A category for the utilities in Alberta. This matter was explored by the Commission in interrogatories and may be explored further during the oral hearing."[992] Finally, the Commission observes that this issue was explored in the oral hearing[993] without objection from AltaGas, and AltaGas addressed this issue in its rebuttal evidence filed on February 28, 2018.[994] The Commission is satisfied that AltaGas had reasonable notice of the Commission's intention to address this issue in this GCOC proceeding as well as an opportunity to make submissions in response, which it did.

836. Turning to the substantive issue, the Commission accepts the evidence presented that the business risk of AltaGas is greater than that of the other utilities in Alberta. This, on its own, suggests that the deemed equity ratio for AltaGas should be greater than the deemed equity ratio for the other utilities, if all were targeted to achieve A-range credit ratings. However, the Commission has determined that the inability of AltaGas to raise debt at A-range credit-rating levels, and the uncertainty with respect to AltaGas's future debt costs, warrants a downward adjustment to the deemed equity ratio of AltaGas, relative to that approved for the other utilities.

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989 Exhibit 22570-X0898, paragraph 35. Exhibit 22570-X0848, PDF page 2.
990 Exhibit 22570-X0616, PDF page 3.
991 Exhibit 22570-X0658, paragraph 6.
992 Exhibit 22570-X0658, paragraph 7.
993 See, for example, Transcript, Volume 3, starting at page 542.
994 Exhibit 22570-X0783, paragraphs 48-50.

837. The Commission agrees with AltaGas that this issue does not relate to the prudence of its long-term debt rates. Rather, the issue relates to 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.

838. The Commission has taken specific note of the evidence in this proceeding with respect to AltaGas's inability to obtain debt at A-range credit-rating levels. In addition, as discussed in Decision 23010-D01-2018, there is uncertainty with respect to the cost of debt that AltaGas's new parent can access (debt which will be mirrored down to AltaGas).[995] In this GCOC proceeding, AltaGas indicated that it "has always obtained debt financing from its parent [AltaGas Ltd.], which has **never** had access to A grade debt. [emphasis added]"[996] Moreover, there is no evidence to suggest that AltaGas will be able to issue new debt at A-range credit-rating levels.

839. Further, AltaGas acknowledged that on a stand-alone basis, it might not be able to achieve an A-range credit rating, because of the small size of its debenture issues. Dr. Villadsen agreed with this. Mr. Buttke indicated that in order to go into the bond index in Canada, the issue size has to be a minimum of $100 million and, by not being in the bond index, one can lose access to a lot of buyers.[997] The Commission notes that the largest debt issuance by AltaGas since 2009 was $45 million, which would not qualify it for inclusion in the bond index. The Commission therefore agrees that AltaGas would likely not be able to achieve an A-range credit rating on a stand-alone basis.

840. Because AltaGas is unable to access lower cost debt that is associated with an A-range credit rating, coupled with the uncertainty of its future debt costs, the Commission considers that AltaGas's deemed equity ratio should be lowered. Otherwise, as Dr. Cleary stated, "consumers bear the costs of both the additional cost of the increase in equity thickness and the cost of paying interest rates above those for an A-rated utility."[998]

841. The Commission notes that a sizeable reduction to AltaGas's deemed equity ratio would be required to target credit ratings in the BBB-range, which would result in AltaGas having a significantly lower deemed equity ratio than the other affected utilities. The Commission does not consider that a reduction of this magnitude is reasonable, particularly given its continued findings regarding AltaGas's business risk, as compared to the other affected utilities. Historically, the Commission has awarded a higher deemed equity ratio to AltaGas than the other affected utilities, to recognize its relatively higher risk. However, the Commission has determined that some reduction in equity thickness is warranted to allow for greater symmetry between the credit rating associated with AltaGas's debt and its equity thickness.

842. In the 2016 GCOC decision, the Commission awarded AltaGas a 41 per cent deemed equity ratio to recognize its risk, relative to the other affected utilities. In this decision, given the Commission's findings that a reduction in the deemed equity ratio is warranted to recognize

[995] In Decision 23010-D01-2018, paragraph 30, the Commission acknowledged that in the event that AltaGas's new parent, AltaGas Utility Holdings (Pacific) Inc., is unable to obtain the investment grade credit rating, it was confirmed that for any new debt issued by AltaGas, the interest expense to be recovered from AltaGas will be based on the interest rate available at the time for investment grade (DBRS, BBB (low) rate debt).
[996] Exhibit 22570-X0820, PDF page 5.
[997] Transcript, Volume 3, page 545.
[998] Exhibit 22570-X0675, UCA-AUC-2018JAN26-005.

AltaGas's inability to obtain debt at A-range credit-rating levels, the Commission finds that a deemed equity ratio of 39 per cent for AltaGas for 2018 to 2020 is reasonable. The Commission considers that the resulting deemed equity ratio balances AltaGas's higher business risk compared to the other affected utilities, with a reduction to account for the actual credit rating associated with AltaGas's debt.

843. Given the evidence on the record of this proceeding, the Commission has determined that a deemed equity ratio of 39 per cent for AltaGas, when combined with an 8.5 per cent ROE for 2018, 2019 and 2020, satisfies the fair return standard.

## 11 Other areas included in scope of the proceeding

### 11.1 Maintaining actual equity ratio in line with deemed equity ratio

844. In this proceeding, the Commission asked AltaGas,[999] AltaLink,[1000] the ATCO Utilities,[1001] ENMAX,[1002] EPCOR[1003] and FortisAlberta[1004] to provide their opinions about whether comparisons between actual equity ratios and the approved deemed equity ratio should be done using actual mid-year data, or actual year-end data, or both. Certain of the utilities[1005] submitted that year-end data should be used; others[1006] submitted that mid-year data should be utilized; and a couple[1007] indicated that both year-end and mid-year data should be used.

845. Mr. Thygesen agreed with FortisAlberta's submission that utilities should consistently attempt to align their actual equity ratios with the deemed equity ratios approved by the Commission.[1008] He contended that the utilities do this every day, and he suggested this could be accomplished by using short-term debt until it builds up to a certain level, and then converting that level of short-term debt to long-term debt.[1009]

846. Mr. Buttke stated that the Commission should not regulate the cash management and debt issuance practices of the utilities on a tactical level. He commented that having low liquidity in a capital intensive business would be a greater concern than Mr. Thygesen's concern about having excess liquidity from time to time. Mr. Buttke indicated that maintaining liquidity and maintaining the ability to fund the utility's capital needs is the primary role of the treasurer, and while minimizing the cost is an important part of that role, it is a secondary role.[1010]

847. AltaGas suggested that short-term debt does not generally comprise a permanent source of capital, and short-term debt balances comprise a small percentage of financing requirements when compared to long-term debt. It submitted that placing prescriptive restrictions on utilities,

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999 Exhibit 22570-X0512, AUI-AUC-2017NOV21-002.
1000 Exhibit 22570-X0438, AML-AUC-2017NOV21-002.
1001 Exhibit 22570-X0352, ATCOUTILITIES-AUC-2017NOV21-002.
1002 Exhibit 22570-X0286, EPC-AUC-2017NOV21-002.
1003 Exhibit 22570-X0434, EDTI-AUC-2017NOV21-002.
1004 Exhibit 22570-X0462, FAI-AUC-2017NOV21-002.
1005 The ATCO Utilities and ENMAX.
1006 AltaGas and FortisAlberta.
1007 AltaLink and EPCOR.
1008 Exhibit 22570-X0551, paragraph 197.
1009 Exhibit 22570-X0551, paragraphs 201-202.
1010 Exhibit 22570-X0749, A63.

by forcing them to rebalance debt and equity ratios on a monthly basis, has the potential to increase costs and decrease efficiencies by having to administer what would be relatively small amounts of long-term debt and equity issues on a monthly basis.[1011]

848. The ATCO Utilities indicated their long-term debt procurement practice is that financing requirements are determined during the year using annual capital expenditure requirements, while targeting the deemed equity ratio at year-end. They stated that their monthly cash balances can fluctuate widely from month to month for a variety of reasons. The ATCO Utilities contended that a daily monitoring regime would introduce inflexibility into its treasury practices.[1012]

849. ENMAX submitted it is unrealistic to expect a utility's capital structure to be exactly aligned with the approved deemed capital structure every day of the year.[1013]

### Commission findings

850. The Commission finds Mr. Thygesen's submission that the utilities should consistently attempt to align their actual and deemed equity ratios by using short-term debt until it builds to a certain level is not realistic. The Commission considers that the continual rebalancing of debt and equity ratios should not take precedence over a utility's cash management practice.

851. Mr. Thygesen recommended that the utilities should allow short-term debt to build up to a certain level and then convert it to long-term debt. He did not provide further detail on this proposal. The Commission considers that a recommendation of this nature must consider how the level of short-term debt should be established for every utility, and how this would factor in the capital expenditure requirements for each year. In addition, this type of recommendation would need to include details on how often a utility should issue long-term debt during a year, and an assessment of the costs and benefits associated with varying levels of short-term debt and long-term debt, including the costs associated with issuing long-term debt in the market.

852. Based on the foregoing, the Commission will not require the affected utilities to consistently attempt to align their actual equity ratios with their deemed equity ratios, by altering their cash management practices as recommended by Mr. Thygesen.

## 11.2 Reporting of information in Rule 005

853. Mr. Thygesen recommended that the affected utilities be required to report monthly cash and cash equivalent levels, in Section 2 of their Rule 005 reports. He submitted this would be a cost-effective method to ensure that the actual equity ratios are maintained at the approved levels.[1014] He further recommended that the utilities also report monthly short-term debt balances in Section 2 of their Rule 005 reports, which he submitted would help to ensure that the utilities are maintaining actual equity ratios in line with their approved deemed equity ratios.[1015]

[1011] Exhibit 22570-X0783, paragraphs 43 and 45.
[1012] Exhibit 22570-X0746, paragraphs 45-46, 49.
[1013] Exhibit 22570-X0773, paragraph 12.
[1014] Exhibit 22570-X0551, paragraph 185.
[1015] Exhibit 22570-X0551, paragraph 203.

854. Mr. Thygesen also submitted that instead of showing mid-year debt balances, which are the average of the opening and closing debt balances, the utilities should report the actual debt balances at mid-year. He stated that while the mid-year debt balance is fairly easy to manipulate, the actual debt balance at mid-year is more accurate.[1016] Mr. Thygesen also suggested that reporting actual debt/equity ratios are misleading when a utility deems debt levels in order to reduce them to the approved percentage.[1017]

855. Mr. Buttke submitted that a requirement to report monthly debt and cash balances could create a mechanism by which the utilities become incented to prioritize relatively small amounts of visible savings over the far more valuable, but less visible, benefits of better risk management.[1018]

856. AltaGas opposed Mr. Thygesen's recommendation that the utilities report monthly cash and cash equivalents, as well as monthly short-term debt balances, in Section 2 of their Rule 005 reports. AltaGas indicated that seasonality of its revenues and capital projects can affect debt/equity ratios from month to month.[1019] AltaGas and the ATCO Utilities submitted that any proposed changes to Rule 005 are outside the scope of this GCOC proceeding.[1020]

857. ENMAX contended that reporting the monthly cash and cash equivalent balances would create an incremental regulatory burden for all utilities, with no material offsetting benefit for ratepayers. It submitted that requiring the monthly production of a cash report is unnecessary, unduly burdensome, and is contrary to one of the fundamental PBR principles, which is to reduce the regulatory burden.[1021] ENMAX stated that as part of the quarterly review of its actual capital structure, it must create a regulated income statement and balance sheet, and there are costs associated with creating these financial documents. ENMAX argued that the cost of producing these financial documents on a daily or monthly basis outweighs the benefits.

**Commission findings**

858. Mr. Thygesen's recommendation that the utilities report monthly cash and cash equivalent levels as well as monthly short-term debt balances as part of their Rule 005 reports was to help ensure that the utilities are maintaining actual equity ratios in line with their approved deemed equity ratios. In Section 11.1, the Commission denied Mr. Thygesen's recommendation that the affected utilities consistently attempt to align their actual equity ratios with their deemed equity ratios by altering their cash management practices. On this basis, the Commission finds there is no reason for the utilities to report monthly cash and cash equivalent levels, or monthly short-term debt balances, as part of their Rule 005 reports.

859. However, the Commission agrees with Mr. Thygesen that the inclusion of deemed debt levels as part of the information reported in Rule 005 can be misleading, and does not necessarily portray an accurate calculation of the actual debt levels maintained by the utility. The Commission therefore directs the utilities, as part of subsequent Rule 005 filings, to report actual debt levels on their "Schedule of debt capital employed" and on their "Summary of mid-year

[1016] Exhibit 22570-X0551, paragraph 182.
[1017] Exhibit 22570-X0551, paragraphs 183-187.
[1018] Exhibit 22570-X0749, A65.
[1019] Exhibit 22570-X0783, paragraph 41.
[1020] Exhibit 22570-X0783, paragraph 43. Exhibit 22570-X0746, paragraph 50.
[1021] Exhibit 22570-X0773, paragraphs 8-9.

capital structure" schedule. In addition, the Commission directs the utilities to report the actual cost rate from their "Schedule of debt capital employed" on their "Summary of return on rate base schedule."

## 11.3 Procedural issues

### 11.3.1 Use of aids to cross-examination

860. During the course of the oral hearing, a number of objections were raised with respect to aids to cross-examination that counsel sought to put before various witnesses.[1022]

861. After ruling on a number of these objections, the panel chair expressed some concern on behalf of the Commission with respect to the number of objections on proposed aids to cross-examination:

> More generally, in our correspondence leading up to this hearing and again in my opening remarks, the Commission encouraged parties to make efficient use of time. The Commission is concerned that the number of objections with respect to aids to cross is becoming disruptive and not an efficient use of the Commission's and parties' time, the cost of which is ultimately borne by ratepayers. We're not looking to impede parties' ability to explore the record or test the evidence, nor do we want to discourage counsel from raising concerns about procedural fairness, but we have through our rulings attempted to provide some guidance relative to the use of aids to cross.[1023]
>
> …
>
> We strongly encourage parties to revisit their planned use of aids to cross in light of the guidance provided and otherwise work amongst themselves and have all the parties work amongst themselves in an attempt to resolve some of these matters.[1024]

862. Repetitive objections and improper use of aids to cross-examination potentially compromise regulatory efficiency and procedural fairness. Given the number and nature of the objections raised during this proceeding, the Commission considers that a review of the proper use of aids to cross-examination is warranted.

863. An aid to cross-examination should be used or referred to only if it assists in the questioning of a witness on his or her evidence. An aid to cross-examination does not become evidence in a proceeding, and cannot be relied on as proof of the matter that the aid to cross-examination purports to prove. It is only what the witness says in relation to the aid to cross-examination that becomes evidence. Therefore, an aid to cross-examination is generally of little value to the Commission and will not be entered on the record if the witness being questioned has neither contributed to the preparation of the document nor confirmed or adopted its content.

864. A valid aid to cross-examination must be relevant to the matter(s) before the Commission and must be put to the witness(es) in a fair manner. While a document may be relevant, the party or counsel who seeks to use the aid to cross-examination must also demonstrate the probative

[1022] For example, Transcript, Volume 1, page 73; Transcript, Volume 1, page 74; Transcript, Volume 1, page 107; Transcript, Volume 1, page 111; Transcript, Volume 1, page 126; Transcript, Volume 2, page 244; Transcript, Volume 2, page 290; Transcript, Volume 4, page 727; Transcript, Volume 7, page 1436.

[1023] Transcript, Volume 3, pages 480-481.

[1024] Transcript, Volume 3, page 481.

nature of the document by tying it to the direct evidence or testimony of the witness(es). Fairness involves sufficient time to review the document as well as allowing the witness to address questions on it in the context of testing the witness's evidence. The document's connection to the evidence and its intended use should be made clear.

865. Further, unless an aid to cross-examination is drawn directly from the witness's direct evidence or testimony, was prepared by that witness in another context, or provides updated or supplementary information to the witness's evidence, it is unfair and improper to ask the witness to verify the information contained in the aid to cross-examination. To do otherwise would allow the aid to cross-examination to be used as a means of introducing new evidence that could have been put to the witness through written interrogatories or been included in a party's filed evidence.

866. It is also an inefficient use of the oral hearing time for counsel to be repeatedly objecting, such as in instances where the relevance and fairness of a particular aid to cross-examination does not appear to be truly in dispute. If a witness is unable to verify or comment on a particular aid to cross-examination, the witness may so indicate. It is not always necessary for counsel to interject, and counsel must be mindful to allow his or her witnesses to answer the questions fairly put to them without interruption.

867. The Commission also requires that the relevant passages of longer aids to cross-examination (five pages or more) be highlighted (Rule 001: *Rules of Practice*, Section 39.2). This has been occasionally disregarded in past practice. Counsel should be aware that the Commission may decide not to allow aids to cross-examination to be put to a witness that do not comply with this requirement.

868. Finally, Section 39 of Rule 001 prescribes a minimum 24-hour notice period where a party intends to use a document as an aid to cross-examination. However, parties are encouraged to provide as much advance notice as is reasonably possible with a view to facilitating the early identification, and possible resolution, of any issues in relation to the use of proposed aids to cross-examination in advance of the hearing.

869. The Commission will consider if changes to its existing process regarding the use of aids to cross-examination could address the above-noted concerns. The Commission may consider these changes as an amendment to Rule 001, or it may direct parties to follow a revised process in specific proceedings if the circumstances merit.

### 11.3.2 UCA concerns regarding process

870. In argument, the UCA submitted that there was a clear resource mismatch between the utilities and interveners in this proceeding, which in its view was amplified by the procedure adopted by the Commission, the extremely condensed nature of the process schedule and the approach adopted by the utilities.[1025] The UCA indicated that the main reason for reiterating timing constraints in this proceeding is to hopefully ensure that sufficient time is allotted to both counsel and witnesses in the next hearing process, so as to accommodate a thorough examination of all information and to recognize that there is a clear mismatch in resources between

[1025] Exhibit 22570-X0897.01, starting at paragraph 360.

interveners and the utilities.[1026] The UCA recommended that the Commission ensure that the process is commenced with sufficient time to allow a prospective determination of the cost of capital while still allowing sufficient time to develop a full record, and that the Commission reconsider a process whereby evidence and rebuttal evidence is filed simultaneously by the utilities and interveners.[1027]

871. In reply, ENMAX objected to the concerns articulated by the UCA and submitted that the sequential process used in this proceeding properly reflects the reality that it is the utilities that bear the onus of proving that all aspects of their rates, including return and capital structure, are just and reasonable.[1028] In their joint reply, AltaLink, EPCOR and FortisAlberta submitted that the UCA had advanced unfounded accusations that should be rejected, that the process for the proceeding was fair and that any argument on future process is for the next GCOC proceeding.[1029] The ATCO Utilities and AltaGas indicated that while they support the UCA's first recommendation regarding establishing future GCOC timelines sufficient to develop a full record and a prospective determination of cost of capital, they did not agree with the UCA's second recommendation.[1030] The ATCO Utilities and AltaGas submitted that the cost of capital is an important component of the utility revenue requirement, and that simultaneous filing of evidence and rebuttal evidence would not be procedurally fair to the utilities.

872. The Commission acknowledges the concerns expressed by the UCA, but will not pre-determine the process for a future GCOC proceeding in this decision. The UCA may highlight any procedural concerns and requests with respect to process at the time of the next GCOC proceeding for the Commission's consideration at that time.

## 12 Implementation of GCOC decision findings

873. In the 2016 GCOC decision, the Commission approved an ROE of 8.5 per cent for all the affected utilities, except ATCO Electric Transmission, on an interim basis for 2018 and any subsequent year thereafter, unless otherwise directed by the Commission.[1031] In the 2016 GCOC decision, the Commission approved a deemed equity ratio of 37 per cent for AltaLink, ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, EPCOR, FortisAlberta, Lethbridge, Red Deer and TransAlta; and a deemed equity ratio of 41 per cent for AltaGas, on an interim basis for 2018 and any subsequent year thereafter, unless otherwise directed by the Commission.[1032] In Decision 22121-D01-2016, the Commission approved an ROE of 8.5 per cent and a deemed equity ratio of 37 per cent for ATCO Electric Transmission on an interim basis for 2018 and any subsequent year thereafter, unless otherwise directed by the Commission.[1033]

874. In light of the Commission's decision to maintain the existing approved ROE of 8.5 per cent and deemed equity ratio of 37 per cent for cost-of-service utilities AltaLink, ATCO Electric Transmission, ATCO Pipelines, EPCOR Transmission, Lethbridge, Red Deer and TransAlta, no

[1026] Exhibit 22570-X0897.01, paragraph 371.
[1027] Exhibit 22570-X0897.01, paragraphs 372 and 374.
[1028] Exhibit 22570-X0909, paragraphs 74-76.
[1029] Exhibit 22570-X0911, paragraphs 83-85.
[1030] Exhibit 22570-X0918, paragraphs 276-278.
[1031] Decision 20622-D01-2016, paragraph 628.
[1032] Decision 20622-D01-2016, paragraph 628.
[1033] Decision 22121-D01-2016, paragraph 10.

adjustment to any approved revenue requirements for 2018, 2019 and 2020 for these utilities will be required with respect to ROE and deemed equity ratios as a result of this decision. As of the date of this decision, ENMAX Transmission has no approved revenue requirement for 2018, 2019 or 2020. The Commission directs any utilities under cost-of-service regulation, being AltaLink, ATCO Electric Transmission, ATCO Pipelines, ENMAX Transmission, EPCOR Transmission, Lethbridge, Red Deer and TransAlta, who do not have Commission-approved revenue requirements for any of 2018, 2019 and 2020, to incorporate the approved ROE and deemed equity ratios as set out in this decision as part of their revenue requirement application(s) for these years.

875. Any affected utility that has a Commission-approved revenue requirement under PBR for 2018 and subsequent years was required to use ROE and deemed equity ratio placeholders for the purpose of the 2018 K-bar accounting test, until values were approved by the Commission on a final basis. In light of the Commission's decision to maintain the existing approved ROE of 8.5 per cent and deemed equity ratio of 37 per cent for all affected distribution utilities, other than AltaGas, no adjustment to the revenue requirements to account for changes in approved ROE or deemed equity ratios should be required for any of the affected utilities under PBR other than AltaGas, as a result of this decision.

876. The Commission directs AltaGas to incorporate the approved deemed equity ratio of 39 per cent for 2018, 2019 and 2020 into all applicable rate proceedings and calculations that rely on this approved deemed equity ratio, including the calculation of its base K-bar as part of the next proceeding addressing adjustments to AltaGas's 2017 notional rate calculations that form the going-in rates for the 2018-2022 PBR term. To the extent that AltaGas, ATCO Gas, ATCO Electric or FortisAlberta consider that this decision impacts the calculation of the income tax expense included in their 2017 notional rate calculations that form the going-in rates for the 2018-2022 PBR term, this may similarly be addressed in the next proceeding considering any required adjustments to their 2017 notional rate calculations.

## 13 Order

877. It is hereby ordered that:

(1) The final approved return on equity for AltaGas Utilities Inc., AltaLink Management Ltd., 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 8.5 per cent for 2018, 2019 and 2020.

(2) The final approved deemed equity ratio for AltaLink Management Ltd., 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 for 2018, 2019 and 2020.

(3) The final approved deemed equity ratio for AltaGas Utilities Inc. is set at 39 per cent for 2018, 2019 and 2020.

Dated on August 2, 2018.

**Alberta Utilities Commission**

*(original signed by)*

Mark Kolesar
Chair

*(original signed by)*

Bill Lyttle
Acting Commission Member

*(original signed by)*

Tracee Collins
Commission Member

*(original signed by)*

Carolyn Hutniak
Commission Member

## Appendix 1 – Proceeding participants

| Name of organization (abbreviation)<br>Company name of counsel or representative |
|---|
| AltaGas Utilities Inc. (AltaGas)<br>MLT Aikins LLP |
| AltaLink Management Ltd. (AltaLink)<br>Borden, Ladner Gervais LLP |
| ATCO Electric Ltd. (ATCO Electric)<br>Bennett Jones LLP |
| ATCO Gas & Pipelines Ltd. (ATCO Gas) (ATCO Pipelines)<br>Bennett Jones LLP |
| Canadian Association of Petroleum Producers (CAPP) |
| Consumers' Coalition of Alberta (CCA)<br>Wachowich & Co. |
| Direct Energy Marketing Limited (Direct) |
| ENMAX Power Corporation (ENMAX)<br>Torys LLP |
| EPCOR Distribution & Transmission Inc. (EPCOR)<br>Fasken Martineau Dumoulin LLP |
| EPCOR Energy Alberta GP Inc. (EEA) |
| FortisAlberta Inc. (FortisAlberta) |
| Industrial Power Consumers Association of Alberta (IPCAA) |
| Office of the Utilities Consumer Advocate (UCA)<br>Reynolds, Mirth, Richards & Farmer LLP |
| The City of Calgary (Calgary)<br>McLennan Ross Barristers & Solicitors |
| TransAlta Corporation (TransAlta) |

Alberta Utilities Commission

Commission panel
M. Kolesar, Chair
B. Lyttle, Acting Commission Member
T. Collins, Commission Member
C. Hutniak, Commission Member

Commission staff
K. Kellgren (Commission counsel)
D. Reese (Commission counsel)
D. Mitchell
D. Ploof
R. Lucas
S. Crawford

# Appendix 2 – Oral hearing – registered appearances

| **Name of organization (abbreviation)**<br>**Name of counsel or representative** | **Witnesses** |
|---|---|
| AltaGas Utilities Inc. and ATCO Utilities<br>R. Jeerakathil<br>L. Smith, QC<br>D. Sheehan | P. Carpenter<br>B. Villadsen<br>R. Buttke<br>M. Stock<br>G. Marghella |
| AltaGas Utilities Inc. (AltaGas)<br>R. Jeerakathil | |
| AltaLink Management Ltd. (AltaLink), EPCOR Distribution & Transmission Inc. (EPCOR) and FortisAlberta Inc. (FortisAlberta)<br>R. Block, QC<br>J. Liteplo<br>J. Hulecki<br>L. Ho<br>J. Hennig<br>L. Mason | R. Hevert<br>D. Koch<br>C. Lomore<br>R. Drotar<br>S. Chaudhary<br>J. Sullivan<br>A. Johnson |
| AltaLink Management Ltd. (AltaLink)<br>R. Block, QC | |
| ATCO Utilities: ATCO Electric Ltd., ATCO Gas and Pipelines Ltd.<br>L. Smith, QC<br>D. Sheehan | |
| ENMAX Power Corporation (ENMAX)<br>D. Wood | J. Coyne<br>A. Barrett<br>J. McCoshen |
| EPCOR Distribution & Transmission Inc. (EPCOR)<br>J. Liteplo<br>J. Hulecki | |
| FortisAlberta Inc. (FortisAlberta)<br>L. Ho<br>J. Hennig<br>L. Mason | |
| The City of Calgary (Calgary)<br>D. Evanchuk | H. Johnson |
| Consumers' Coalition of Alberta (CCA)<br>J. Wachowich, QC | J. Thygesen<br>D. Madsen |
| Office of the Utilities Consumer Advocate (UCA)<br>R. McCreary<br>B. Schwanak | S. Cleary<br>R. Bell |

Alberta Utilities Commission

Commission panel
M. Kolesar, Chair
B. Lyttle, Acting Commission Member
T. Collins, Commission Member
C. Hutniak, Commission Member

Commission staff
K. Kellgren (Commission counsel)
D. Reese (Commission counsel)
D. Mitchell
D. Ploof
R. Lucas

## 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 Commission finds that because of the finite life of income tax loss carryforwards, as opposed to the indefinite life of deductions such as capital cost allowance, the conservative practice would be for utilities not to forecast income tax losses, but instead, forecast the use of discretionary deductions such as capital cost allowance in order to reduce forecast taxable income to zero. Accordingly, the Commission directs the utilities, when forecasting income taxes, to only claim allowable deductions that will reduce the taxable income to a maximum of zero. ........................................................ Paragraph 99

2. The Commission agrees with AltaGas and the ATCO Utilities that reporting the unfunded FIT liability would have no bearing on their financial performance. However, given the magnitude of the unfunded FIT balances that were forecast as of December 31, 2017, and the Commission's consideration that the calculation and reporting of this balance on an annual basis would not require a significant amount of effort, the Commission directs the ATCO Utilities, FortisAlberta, AltaGas and AltaLink to include their unfunded FIT liability balance each year as part of their Rule 005 reports, beginning with the Rule 005 report for 2018, that will be submitted in 2019. The information provided should consist of the unfunded FIT liability for the year being reported, as well as the previous year, and the resulting difference. This information may assist the Commission in assessing the level of potential credit metric relief that may be available if a utility were to apply to adopt the FIT method. ...................................................................... Paragraph 102

3. The Commission notes that adjustments will be made to the distribution utilities' going-in PBR rates in future proceedings. For example, adjustments to going-in rates will be required to reflect 2017 approved capital tracker amounts and to account for any approved depreciation changes. The Commission directs AltaGas to revise the calculation of its base K-bar to incorporate the findings in this decision as part of the next proceeding addressing adjustments to AltaGas's going-in PBR rates. To the extent that ATCO Gas, ATCO Electric or FortisAlberta consider that this decision impacts the calculation of the income tax expense included in 2018 going-in rates, this may similarly be addressed in the next proceeding considering any required adjustments to their respective going-in PBR rates. ........................................................................................ Paragraph 135

4. However, the Commission agrees with Mr. Thygesen that the inclusion of deemed debt levels as part of the information reported in Rule 005 can be misleading, and does not necessarily portray an accurate calculation of the actual debt levels maintained by the utility. The Commission therefore directs the utilities, as part of subsequent Rule 005 filings, to report actual debt levels on their "Schedule of debt capital employed" and on their "Summary of mid-year capital structure" schedule. In addition, the Commission directs the utilities to report the actual cost rate from their "Schedule of debt capital employed" on their "Summary of return on rate base schedule." ................. Paragraph 859

5. In light of the Commission's decision to maintain the existing approved ROE of 8.5 per cent and deemed equity ratio of 37 per cent for cost-of-service utilities AltaLink, ATCO Electric Transmission, ATCO Pipelines, EPCOR Transmission, Lethbridge, Red Deer

and TransAlta, no adjustment to any approved revenue requirements for 2018, 2019 and 2020 for these utilities will be required with respect to ROE and deemed equity ratios as a result of this decision. As of the date of this decision, ENMAX Transmission has no approved revenue requirement for 2018, 2019 or 2020. The Commission directs any utilities under cost-of-service regulation, being AltaLink, ATCO Electric Transmission, ATCO Pipelines, ENMAX Transmission, EPCOR Transmission, Lethbridge, Red Deer and TransAlta, who do not have Commission-approved revenue requirements for any of 2018, 2019 and 2020, to incorporate the approved ROE and deemed equity ratios as set out in this decision as part of their revenue requirement application(s) for these years. ........................................................................................................................ Paragraph 874

6. The Commission directs AltaGas to incorporate the approved deemed equity ratio of 39 per cent for 2018, 2019 and 2020 into all applicable rate proceedings and calculations that rely on this approved deemed equity ratio, including the calculation of its base K-bar as part of the next proceeding addressing adjustments to AltaGas's 2017 notional rate calculations that form the going-in rates for the 2018-2022 PBR term. To the extent that AltaGas, ATCO Gas, ATCO Electric or FortisAlberta consider that this decision impacts the calculation of the income tax expense included in their 2017 notional rate calculations that form the going-in rates for the 2018-2022 PBR term, this may similarly be addressed in the next proceeding considering any required adjustments to their 2017 notional rate calculations. ......................................................................................... Paragraph 876

## Appendix 4 – Abbreviations

| Abbreviation | Name in full |
|---|---|
| 2004 GCOC decision | Decision 2004-052, Generic Cost of Capital |
| 2009 GCOC decision | Decision 2009-216, 2009 Generic Cost of Capital |
| 2011 GCOC decision | Decision 2011-474, 2011 Generic Cost of Capital |
| 2013 GCOC decision | Decision 2191-D01-2015, 2013 Generic Cost of Capital |
| 2016 GCOC decision | Decision 20622-D01-2016, 2016 Generic Cost of Capital |
| ACFA | Alberta Capital Financing Authority |
| AESO | Alberta Electric System Operator |
| AILP | AltaLink Investments, L.P. |
| ALP | AltaLink, L.P. |
| AltaGas | AltaGas Utilities Inc. |
| AltaLink | AltaLink Management Ltd. |
| ARCH | autoregressive conditional heteroscedasticity |
| ATCO Electric | ATCO Electric Ltd. |
| BHE | Berkshire Hathaway Energy Company |
| Board | Alberta Energy and Utilities Board |
| bps | basis points |
| BYPRPM | bond yield plus risk premium model |
| CAD | Canadian dollar |
| CAD/USD | Canadian dollar to the United States dollar |
| Calgary | The City of Calgary |
| CAPM | capital asset pricing model |
| CAPP | Canadian Association of Petroleum Producers |
| CCA | Consumers’ Coalition of Alberta |
| CIBC | Canadian Imperial Bank of Commerce |
| CRA | Canada Revenue Agency |
| CV | coefficient of variation |
| CWIP | construction work in progress |
| DACDA | direct assigned capital deferral account |
| DBRS | DBRS Limited |
| DCF | discounted cash flow |
| EBIT | earnings before interest and income taxes |
| EBITDA | earnings before interest, income taxes, depreciation and amortization |
| ECAPM | empirical capital asset pricing model |
| ENMAX | ENMAX Power Corporation |
| EPCOR | EPCOR Distribution & Transmission Inc. |
| EPS | earnings per share |
| EUI | EPCOR Utilities Inc. |
| FFO | funds from operations |
| FIT | future income tax |
| FortisAlberta | FortisAlberta Inc. |
| GARCH | generalized form of ARCH |
| GCOC | generic cost of capital |
| GDP | gross domestic product |

| Abbreviation | Name in full |
|---|---|
| GOC | Government of Canada |
| GRA | general rate application |
| GTA | general tariff application |
| IBES | Institutional Brokers' Estimate System |
| I factor | inflation factor |
| IMF | International Monetary Fund |
| IR | information request |
| LDC | local distribution companies |
| Lethbridge | City of Lethbridge |
| MC Alberta | MidAmerican (Alberta) Canada Holdings Corporation |
| MERP | market equity risk premium |
| Moody's | Moody's Investor Services |
| MPR | Monetary Policy Report |
| NAFTA | North American Free Trade Agreement |
| NOI | net operating income |
| O&M | operating and maintenance |
| P/B | price-to-book |
| PBR | performance-based regulation |
| PP&E | property, plant and equipment |
| PRPM | predictive risk premium model |
| RBC | Royal Bank of Canada |
| Red Deer | City of Red Deer |
| ROE | return on equity |
| S&P | Standard & Poor's |
| SML | security market line |
| the affected utilities | AltaGas Utilities Inc., the ATCO Utilities (ATCO Electric Ltd., ATCO Gas and Pipelines Ltd.), ENMAX Power Corporation, EPCOR Distribution and Transmission Inc., FortisAlberta Inc., City of Lethbridge, City of Red Deer and TransAlta Corporation |
| the ATCO Utilities | ATCO Electric Ltd., and ATCO Gas and Pipelines Ltd. |
| the Fed | the Federal Reserve System |
| TransAlta | TransAlta Corporation |
| TSX | Toronto Stock Exchange |
| U.S. | United States |
| UAD | utility asset disposition |
| UAD decision | Decision 2013-417, Utility Asset Disposition |
| UCA | Office of the Utilities Consumer Advocate |
| USD | U.S. dollar or United States dollar |
| VIX | 30-day implied volatility of the S&P index (representing the stock market in the U.S.) |
| VIXC | 30-day implied volatility of the S&P/TSX 60 index (representing the stock market in Canada) |
| WCS | Western Canadian Select |
| WTI | West Texas Intermediate |