Reference: Volume 3, Cost of Capital Report by James Coyne

Q. Volume 3, Cost of Capital Report by James Coyne, page 31, line 4 to page 32, line 11. Have there been any regulatory decisions in Canada since the Board's Order No. P.U. 18(2016) that have used unadjusted U.S. data in setting a fair return for a Canadian regulated utility? If yes, provide a copy of the decision.

A. Yes. See Attachments A through C.

Attachment A: 2016 British Columbia Utilities Commission ("BCUC") FortisBC Energy, Inc.

Attachment B: 2018 Alberta Utilities Commission ("AUC") Generic Cost of Capital

Attachment C: 2019 Island Regulatory and Appeals Commission Maritime Electric Company Ltd.

Attachments A through C are available in electronic format on Newfoundland Power's stranded website at: https://ftp.nfpower.nf.ca/.

Also, see response to Request for Information CA-NP-127 for summaries and quotes from the BCUC and AUC decisions.

2016 British Columbia Utilities Commission FortisBC Energy, Inc.

British Columbia Utilities Commission

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Acting Commission Secretary

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VIA EFILE
gas.regulatory.affairs@fortisbc.com

August 10, 2016

Ms. Diane Roy
Director, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc.
Project No. 3698852
Application for its Common Equity Component and Return on Equity for 2016

Further to your October 2, 2015 filing of the above noted application, enclosed please find the British Columbia Utilities Commission's decision.

Yours truly,

Original Signed By Doug Chong for:

Laurel Ross

/nd
Enclosure

British Columbia
Utilities Commission

IN THE MATTER OF

**FortisBC Energy Inc.
Application for its Common Equity Component
and Return on Equity for 2016**

DECISION

and Order G-129-16

August 10, 2016

Before:
K. A. Keilty, Commissioner/Panel Chair
D. A. Cote, Commissioner
N. E. MacMurchy, Commissioner

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EXECUTIVE SUMMARY

On October 2, 2015, FortisBC Energy Inc. (FEI) filed an application for a review of its common equity component and return on equity (ROE) for 2016 in compliance with British Columbia Utilities Commission (Commission) Order G-75-13. After considering and weighing the evidence and submissions in this proceeding, the Panel has determined the following, effective January 1, 2016:

- **FEI's common equity component is set at 38.5 percent;**
- **FEI's ROE is set at 8.75 percent;**
- **The use of the Automatic Adjustment Mechanism (AAM) is suspended indefinitely;**
- **The common equity component and ROE approved for FEI in this decision will serve as the benchmark cost of equity for any other utility in British Columbia that uses the benchmark utility to set rates; and**
- **The common equity component and ROE will remain in effect until otherwise determined by the Commission.**

In reaching this decision, the Panel applied the Fair Return Standard to ensure that the common equity component and ROE met the three tests for a just and reasonable return on equity: the comparable investment, financial integrity and the capital attraction requirements.

<u>Contextual issues</u>

The Panel considered three issues to establish the context for this decision: the key determinations in the 2013 Generic Cost of Capital Decision; the changes in global and economic conditions since 2012; and reliance on decisions and data from other jurisdictions. The 2013 Generic Cost of Capital (GCOC) Decision is viewed by the Panel to be a reasonable reference point to assist in the evaluation of the evidence presented in the current proceeding, including the determinations with respect to the use of the capital asset pricing model (CAPM) and the discounted cash flow (DCF) models and the use of proxy companies comparable to FEI. The expert witnesses in the current proceeding focused on these two models using comparable Canadian and US data. With respect to changes in economic and global market conditions, all parties in this proceeding agree that current conditions are substantially the same as existed at the time of the 2012 GCOC proceeding.

<u>Dealing with uncertainty</u>

As is the case in all hearings dealing with ROE and common equity ratio determinations, in making its decision the Panel is faced with a number of uncertainties. This requires the application of judgment, informed by the evidence on record in the proceeding. The Panel noted a number of areas where uncertainty exists including:

- The use of imperfect models that rely on significant assumptions, subject to a high degree of uncertainty and variability;
- The use of US proxy companies subject to differences in the regulatory treatment and evidence of growth rate instability;
- Reliance on a Canadian group of proxy companies whose business interests are not directly comparable FEI's due to the lack of stand-alone publically traded natural gas distribution companies in Canada;
- The impact of distortions to capital markets resulting from the abnormal conditions in the bond markets resulting from the impact of global bond buying programs;
- Uncertainty with respect to the appropriate adjustment to raw betas for low risk utilities; and

- Sensitivity of the DCF model to growth rate assumptions.

The Panel has endeavoured to deal with these uncertainties by: (a) identifying the uncertainties and quantifying them where possible; (b) using different financial models as a check against the other; and (c) and while not determinative, considering the findings of other regulatory bodies in Canada.

Fair Return Standard

The expected rate of return investors require is based on the risk-return alternatives available in competitive capital markets. The financial models are the primary means used by FEI and interveners to estimate the comparable return available to investors from other entities of like risk. The expert witnesses in this proceeding used both Canadian and US proxy companies to provide input to their models. In determining the appropriate weight to place on the models, the Panel recognized the models are imperfect and considered the totality of the evidence. The Panel noted both the CAPM and DCF model rely on proxy group information and a selection of proxy companies that are imperfect comparators due to business and regulatory environments that differ from FEI. Further, given the current global economic and capital market environment, the reliability of the models is called into question more than in the previous cost of capital hearings, requiring the Panel to exercise its judgement to a greater degree. The Panel also considers whether conditions have changed sufficiently since the 2012 GCOC proceeding to warrant an increase or decrease in ROE. After assessing the output of the models and weighing the uncertainties, the Panel determined that maintaining the return on equity at 8.75 percent is appropriate.

In assessing the common equity component, the Panel determined that while there are some differences in the risks facing FEI relative to the time of the 2012 GCOC proceeding, the changes are not of a substantial nature requiring a change to FEI's ROE or common equity ratio. As a check, the Panel considered that the common equity component and ROE determined by the Panel situates FEI appropriately based on its relative risk to comparable Canadian natural gas distribution utilities.

With respect to debt financing, FEI's ability to attract capital and maintain its financial integrity is impacted by its credit rating. The Panel considered whether a higher ROE or common equity ratio is necessary to maintain FEI's current "A" credit rating given FEI's metrics weak financial metrics relative to the required metrics for a credit rating in the "A" category. The Panel agrees with FEI that maintenance of an A credit rating helps ensure FEI's access to capital in most market conditions, and among other benefits, ensures a lower cost of borrowing. The Panel is not persuaded that the high level of capital expenditures that FEI has planned through 2018 will impact its credit rating given the Panel has maintained of its current allowed ROE and common equity component.

The Panel assessed whether an increase in its common equity component was necessary to support FEI's ongoing debt issuance capacity under its Trust Indenture as a result of the significant new capital requirements facing FEI in the next few years. The Panel concluded that assuming both a 5.0 percent and 6.0 percent yield on new debt issuances, FEI has sufficient capacity under its Trust Indenture to meet its financing needs in the 2016 to 2018 period. The Panel noted FEI does not become constrained until interest rates reach 7.0 percent which given the expert evidence on forecast interest rates for this period, the Panel considers unlikely. Further, in the event FEI is faced with interest rates at this level it has other alternatives including its ability to issue secured debt, alter the timing of certain capital expenditure or bring an application to the Commission for a change in ROE. Accordingly, the Panel is of the view that an increase is ROE or common equity ratio is not required to support FEI's ability to issue debt under its Trust Indenture.

The Panel concludes an ROE of 8.75 percent and common equity component of 38.5 percent meet the comparable investment, capital attraction and financial integrity requirements.

Automatic Adjustment Mechanism

The Panel continues to hold the view that an effective AAM can be a useful tool in providing an updating mechanism for ROE, thereby eliminating some of the need for lengthy and expensive formal reviews. However, we acknowledge that economic conditions are uncertain and accept Dr. Booth's explanation of long Canada bond yields are less affected by investors and more by central banks' policies. Therefore, the Panel does not believe that continuing with an AAM at this time will necessarily result in changes reflecting a fair ROE or meeting the Fair Return Standard.

FEI as the benchmark utility

The Panel notes that there was general agreement among the parties with respect to FEI being made the benchmark for the GCOC proceeding. Accordingly, the common equity component and ROE approved in this decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.

1.0 INTRODUCTION

1.1 Overview of the application

On October 2, 2015, FortisBC Energy Inc. (FEI) filed an application for a review of its common equity component and return on equity (ROE) for 2016 (Application) pursuant to the British Columbia Utilities Commission (Commission) decision in the 2012 Generic Cost of Capital (GCOC) Stage 1 proceeding. In the Application, FEI requests approval of a capital structure of 40 percent equity and 60 percent debt and a return on common equity of 9.5 percent for 2016.[1] This compares to FEI's currently allowed ROE of 8.75 percent and common equity component of 38.5 percent.

1.2 Background

In the 2013 GCOC Decision rendered on May 10, 2013,[2] the Commission determined that:

- FEI's common equity ratio is reduced from 40.0 percent to 38.5 percent, effective January 1, 2013.
- FEI's ROE is set at 8.75 percent, effective January 1, 2013 until December 31, 2015, subject to variation commencing January 1, 2014, by an Automatic Adjustment Mechanism (AAM) formula.
- The AAM formula, based on a two factor model, was to be applied annually to set the ROE of the benchmark utility between ROE proceedings. It will commence in 2014 and operate until December 31, 2015. The implementation of the AAM would only be applied when the long Canada bond yield met or exceeded 3.8 percent.

Commission Order G-75-13 accompanying the 2013 GCOC Decision directed the benchmark utility, FEI, to file an application for the review of its common equity component and ROE approved in that order by no later than November 30, 2015.

Since the 2013 GCOC Decision, FEI has undergone an amalgamation of three affiliated utilities serving distinct service areas: the former FortisBC Energy Inc., FortisBC Energy (Whistler) Inc. (FEW) and FortisBC Energy (Vancouver Island) Inc. (FEVI), to become Amalgamated FEI or, as used in this Application, FEI.

On October 2, 2015, in compliance with Order G-75-13, FEI filed its Application pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA) seeking approval of its proposed capital structure and return on common equity to take effect January 1, 2016.

At the time of the filing of this Application, FEI's Annual Review of 2016 Delivery Rates proceeding was before the Commission, and FEI's existing common equity component and return on equity was approved as interim in that proceeding, effective January 1, 2016, pending the outcome of this Application.[3] Order G-204-15 ordered that FEI's common equity component and return on equity would remain the benchmark on an interim basis effective January 1, 2016.

[1] Exhibit B-1, p. 1.
[2] British Columbia Utilities Commission Generic Cost of Capital Stage 1 (2013 GCOC), Decision dated May 10, 2013, Order G-75-13.
[3] FortisBC Energy Inc. Annual Review of 2016 Delivery Rates, Order G-193-15 with Reasons for Decision dated December 7, 2015.

1.3 Purpose and scope of the proceeding

The purpose of the proceeding is to establish a fair return for FEI based on the Fair Return Standard and the standalone principle. The focus of this proceeding is on matters that directly affect the fair return of FEI. These matters include:

- Consideration of the amalgamation being a factor affecting FEI's business risk;
- Changes in business risk since the 2012 GCOC proceeding, independent of the effect of amalgamation;
- Changes in economic conditions and capital markets since 2012 and their impact on FEI's cost of capital; and
- Consideration of the appropriate means of determining the allowed ROE reflecting the rate of return being earned by comparable companies.

In addition, this decision examines the need for continuation of an AAM. In accordance with this, by Order G-204-15, the Commission determined that a regulated utility that uses the benchmark to establish its rates must apply to the Commission if it wishes to have its rates made interim pending the outcome of this proceeding. This decision determines the role of FEI as a benchmark utility.

1.4 Regulatory process

The regulatory review was by way of a limited scope oral hearing, as proposed by FEI, which took place after two rounds of information requests (IRs) to FEI and one round of IRs on Intervener Evidence.[4]

Six parties registered as interveners in this proceeding:

1. Commercial Energy Consumers Association of British Columbia (CEC);
2. British Columbia Municipal Electrical Utilities (BCMEU);
3. British Columbia Hydro and Power Authority (BC Hydro);
4. British Columbia Old Age Pensioners' Organization *et al*. (BCOAPO);
5. Industrial Customers Group (ICG); and
6. Association of Major Power Customers of BC (AMPC).

Among the registered interveners, CEC, BCOAPO and AMPC: collectively the "Utility Customers," were most active and they jointly sponsored the expert evidence of Dr. Laurence Booth of the University of Toronto. CEC and AMPC participated separately in the IR process, cross-examination and filing of final submissions. BCOAPO separately participated in the IR process but joined AMPC in filing its final submission. ICG participated in the second round of the IR process and filed a final submission.

A number of regulated utilities either registered as interested parties or provided Letters of Comment to this proceeding in order to provide their views related to issues such as interim rates for utilities that rely on the benchmark utility for setting rates.

---

[4] Exhibit A-2, Commission Order G-177-15 dated November 9, 2015.

The oral hearing took place from March 9, 2016 to March 11, 2016 where participants cross-examined the expert witnesses, Mr. James Coyne of Concentric Energy Advisors and Dr. Laurence Booth of the University of Toronto, representing respectively, FEI and the Utility Customers.

At the close of the oral hearing, counsel for FEI, AMPC and CEC submitted in turn to the Panel that there was no further need for questions on the business risk of FEI. Accordingly, the Panel closed the evidentiary record on March 11, 2016 and, based on agreement from all parties, established the timing for FEI's final submission, intervener final submissions and FEI reply submission to take place from April 3, 2016 to April 28, 2016.

On May 5, 2016, AMPC sought leave from the Commission to file two narrow sur-reply submissions based on its view that there were new issues raised in FEI's reply submission. The Commission, after considering comments from FEI and other interveners, allowed the sur-reply to remain on record by Order G-68-16. With the admission of AMPC's sur-reply on the record, the argument phase for this proceeding ended on May 13, 2016, the date the Commission accepted the sur-reply by Order G-68-16.

1.5 Approach to the decision

The legal framework for determining a fair return for a regulated utility is called the Fair Return Standard and is discussed in Section 2.

There are a number of broader issues of importance which are contextual in nature and include the following:

- The key determinations in the 2013 GCOC Decision and relevance to this proceeding;
- Changes in economic and global market conditions since 2012/2013; and
- Consideration of other jurisdictions.

These issues are discussed in Section 3 and provide the Panel with a context to assist in reviewing and assessing the evidence.

Section 4 deals with an appropriate capital structure given FEI's business risk and consideration of other items impacting common equity component including: credit ratings, FEI's ability to issue debt under its Trust Indenture and the common equity component decisions in other jurisdictions.

Section 5 considers the appropriate ROE for the benchmark utility with a review of some of the key issues and models employed by the expert witnesses.

Section 6 examines potential AAM models and whether there is justification to continue to rely on such a mechanism. Section 7 deals with the role of FEI as a benchmark utility.

2.0 APPLICATION OF THE FAIR RETURN STANDARD

The principles of the Fair Return Standard were established by the Supreme Court of Canada in the Northwestern Utilities v. City of Edmonton (1929) case. The Fair Return Standard is the legal test applied to ensure that investors receive the opportunity cost on their investment represented by the rate of return investors could expect to earn elsewhere without bearing more risk.

In summary, the Fair Return Standard is fundamental to cost of equity proceedings and has three requirements or tests to be met for a fair and reasonable return on capital:

a) The comparable investment requirement;

b) The financial integrity requirement; and

c) The capital attraction requirement.

FEI submits that under the Fair Return Standard, the overall rate of return allowed for FEI (i.e., the combined capital structure and return on equity must meet the above three distinct elements of the test) must not compromise FEI's legitimate cost of service resulting from these tests in order to achieve lower rates in the short run; must account for the risks that FEI faces in achieving its return on and of its invested capital; and must allow FEI to maintain appropriate access to capital, particularly with FEI's significant capital investment requirements.[5]

In this proceeding, no party has directly challenged the Fair Return Standard or the regulatory compact, although FEI argues that some parties have indirectly done so by raising the issue of rate impacts and by characterizing rates that provide an appropriate risk adjusted rate of return as being unnecessarily high.[6]

AMPC/BCOAPO submit that FEI made an irrelevant argument because AMPC/BCOAPO have not made any submissions related to their members' ability to pay rates but concede the Commission should not simply ignore how its decision will affect ratepayers. They submit the Commission's mandate requires it to balance the interests of ratepayers and utilities investors.[7]

Consistent with previous decisions and the "regulatory compact" the Panel confirms that it has a duty to approve rates that meet this standard, and to provide a reasonable opportunity for the utility to earn a fair return on invested capital. The Panel also concurs with the finding in the 2013 GCOC Decision that in assessing the Fair Return Standard, the utility must be assessed on the basis of the standalone principle. That is, it must be assessed as if FEI is a stand-alone entity, raising capital on the merits of its own economic, business and financial characteristics.[8] No party challenged the application of this principle.

The Panel has not considered rate impacts that result from the revenue required to yield the fair return. The Panel recognizes that once a revenue requirement that has been established consistent with the Fair Return Standard and the regulatory compact, an assessment is required to determine not only that the rates give the utility the opportunity to realize its revenue requirements but also to ensure the rates that are set are structured so that they are consistent with the UCA requirement that they must not be "unjust" or "unreasonable" by being "more than a fair and reasonable charge for the service of the nature and quality provided by the utility."[9]

[5] FEI Final Submission, pp. 8–10.
[6] FEI Final Submission, p. 12.
[7] AMPC/BCOAPO Final Submission, p. 13.
[8] 2013 GCOC Decision, p. 100.
[9] *Utilities Commission Act*, RSBC 1996, Chapter 473, section 59(5).

The Panel agrees with the finding in the 2013 GCOC Decision: "The Commission observes that the application of the FRS (*Fair Return Standard*) leaves room for disagreement, judgment and discretion."[10]

3.0 CONTEXTUAL ISSUES

3.1 Determinations in the 2013 Generic Cost of Capital Decision

3.1.1 Key determinations in the 2013 GCOC Decision

The 2012 GCOC proceeding was initiated by the Commission in 2012 to review and determine the ROE and capital structure for a benchmark low-risk utility, which was last set in 2009 by Commission Order G-158-09 on December 16, 2009.

In the 2012 GCOC proceeding, FEI filed detailed company evidence and tendered four expert witnesses who presented to the Commission a variety of models for determining the appropriate ROE using a number of methodologies that vary in structure, assumptions and the data from which the model results were estimated. The proceeding also raised a number of broader issues that were contextual in nature. The key determinations of the 2013 GCOC Decision are summarized below:

a) Weighting of the models – it was determined that the two most compelling frameworks for assessing the cost of equity are the discounted cash flow (DCF) model and the capital asset pricing model (CAPM). These two models were given equal weight when determining the allowed ROE.[11]

b) Relevance of US data - it was determined that it was appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the AAM (2006 TGI ROE) Decision and again in the 2009 Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. Return on Equity and Capital Structure (2009 TGI ROE) Decision. However, the Commission did not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities. It was of the view that the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which might exist.[12]

c) Comparability with other Canadian jurisdictions - the Commission took the view that it is important to consider the methodologies, approaches and regulatory principles related to other jurisdictions' decision. However, it did not accept that results and values from other jurisdictions could be used for the purposes of determining the ROE and common equity component requirements for utilities in BC.[13]

d) Relevance of disparity between allowed and actual ROE[14] - as part of assessing the relevance of the disparity between "allowed" and "actual" ROE, the Commission considered the question of whether FEI faced any short-run risks with respect to its ability to annually earn its allowed ROE given its strong track

[10] 2013 GCOC Decision, p. 8.
[11] 2013 GCOC Decision, p. 80.
[12] 2013 GCOC Decision, pp. 19–20.
[13] 2013 GCOC Decision, p. 20.
[14] The Commission approves a ROE that meets the Fair Return Standard. Based on the approved ROE, a revenue requirement is calculated and rates are set and approved by the Commission at levels that are judged to allow the utility the opportunity to earn its approved ROE. The utility may earn more than its approved ROE or less, depending on the efficiency of its operations and on the economic circumstances it encounters. The term "allowed ROE" or "approved ROE" means the ROE found by the Commission that meets the Fair Return Standard. The term "actual ROE" or "realized ROE" refers to the ROE that the utility ends up achieving.

record of earning more than its approved ROE. The Commission noted that there was no evidence to suggest investors are likely to make a major distinction between short-term and long-term risk; and accordingly, concluded that the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings and management's proactive approach.[15]

e) Financing flexibility adjustment - expert witnesses in the 2012 GCOC proceeding proposed financial flexibility adjustments ranging from 32 to 100 basis points (bps), dependent on a variety of conditions. The Commission approved the addition of 50 bps to be added to the CAPM and DCF tests in determining the fair ROE after reviewing a range of proposed allowances.[16]

3.1.2 Relevance to current proceeding

The key determinations of the contextual issues in the 2013 GCOC Decision provide the Panel in this proceeding with some guidance when considering the evidence in this proceeding.

3.2 Changes in economic and global market conditions since 2012

All parties in this proceeding approached the review of FEI's proposed ROE and common equity ratio by focusing on the changes in economic and capital market conditions since 2012 rather than undertaking a full analysis of current market conditions. The Panel accepts this approach and considers that changes in the economic and global market conditions should, among other considerations, inform its decision on whether the ROE and common equity component established in the 2013 GCOC Decision should increase, remain in place, or decrease.

In the current proceeding, all parties agree economic and capital market conditions remain much as they were in 2012. With respect to the changes since 2012, Mr. Coyne states:

> Generally, current capital market conditions are not dissimilar to what they were in June 2012. Capital markets continue to recover from the global economic crisis of 2008-2009, but at a slower than expected pace and have shown little change from when FEI last filed its GCOC evidence in 2012. Bond yields have remained low and utility bond spreads have remained somewhat elevated, with no significant movements since June 2012.[17]
>
> …Though financial markets have reflected more optimism in valuations, recent financial market volatility indicates that optimism may be waning and uncertainty persists in today's financial markets, as it did in June 2012, as the pace of recovery proves slower than expected and the impact of China's economic slowdown has yet to be fully realized on the global economy. Though it is difficult to predict what will unfold, I would not characterize the global economy as appreciably improved today from where it stood in its recovery in June 2012, and accordingly, I would not expect investors to view current capital market conditions as dissimilar to those in June 2012.[18]

In Dr. Booth's view, since 2012, conditions have been in a "holding pattern" waiting for the US and Europe to recover from the effects of their recessions. He indicates that the recovery has been impacted by slowed growth

[15] 2013 GCOC Decision, p. 22.
[16] 2013 GCOC Decision, p. 80.
[17] Exhibit B-1, Appendix B, p. 22.
[18] Exhibit B-1, Appendix B, p. 24.

in China which also impacted commodity markets and triggered a correction in the stock market. Dr. Booth states:

> The upshot is that the stronger markets that were expected at that time have not developed as anticipated and Alberta, in particular has been badly hit. Further conditions in the bond market have become even looser than they were in 2012 as the massive amount of liquidity in global markets continues to increase, depressing bond yields.[19]

FEI describes the current Canadian environment as continuing to be dominated by uncertainty and as "not materially different form 2012 levels."[20]

Mr. Coyne analyzes the corporate bond market and notes the Canadian Utilities A-related spread over 30-year government bonds was 1.588 percent in June 2012 verses 1.868 percent in August 2015, an increase of 28 bps.[21] Mr. Coyne states this increase indicates ongoing risk aversion in the wake of continued economic uncertainty. Mr. Coyne also analyzes the change in FEI bond spreads and concluded that FEI's bond spread has increased since June 2012. It is also Mr. Coyne's opinion that the average Canadian distribution utility bond spreads have increased more than the Corporate A-rated bond spreads.[22]

Dr. Booth states that utilities continue to have easy access to debt markets at very low interest rates and similar to 2012, conditions are very receptive to "good credits" like Canadian utilities.[23]

<u>Intervener submissions</u>

CEC describes capital market conditions as not being dissimilar to what they were in June 2012, and capital markets have continued to recover from the global economic crisis of 2008-2009, but at a slower than expected pace.[24]

AMPC/BCOAPO submit the decrease in long Canada yields reflect lower utility borrowing costs, allowing FEI to access the bond market on more favourable terms than in 2013 and resulting in FEI having a lower embedded debt cost, an increase in its interest coverage ratio and an enhancement of its financial flexibility.[25]

<u>FEI reply submission</u>

FEI submits the increase in credit spreads is an indicator of increased investor risk aversion regarding utility equity and therefore implies a higher cost of equity.[26]

FEI submits Dr. Booth has not accounted for credit spreads which quantifies the compensation investors demand for making investment in relationship to risk free rate and in addition, the increased credit spreads since 2012 are an indicator of increased risk of a utility investment.[27]

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[19] Exhibit C7-7-2, pp. 2–3.
[20] Exhibit B-1, p. 13.
[21] Exhibit B-1, Appendix B, p. 19.
[22] Exhibit B-9, BCUC IR 32.2.
[23] Exhibit C7-7-2, pp. 34–45.
[24] CEC Final Submission, p. 10.
[25] AMPC/BCOAPO Final Submission p. 37.
[26] FEI Final Submission, p. 32.

Panel discussion

While FEI and AMPC/BCOAPO differ in their interpretation of the meaning of recent movement of utility credit spreads, the Panel accepts that there is little disagreement among the parties that the economic condition of the BC economy and capital market conditions are not materially different from the 2012 levels. In this proceeding, similar to the approach set out in the 2013 GCOC Decision, the Panel has to assess a number of elements to determine if a change in FEI's ROE and common equity component is appropriate. This analysis includes weighing the impact of the changes in economic conditions and global market conditions since 2012 and the extent to which changes in these conditions imply changes in an investor's opportunity cost.

3.3 Consideration of other jurisdictions

The "comparable investment requirement" of the Fair Return Standard requires the return available from the application of the utility's invested capital to be comparable to the return of other enterprises of like risk. The challenge posed by a comparability test is to find a group of proxy companies that reflect the substantially similar environment facing FEI, including the market, regulatory, financial, environmental and political circumstances affecting current and future economic prospects.

All parties acknowledge there are no publically-traded, pure play gas distribution companies in Canada. Hence, both the FEI and the Utility Customers' expert witnesses assessed a sample of US companies that are primarily engaged in natural gas distribution in order to assess the market expectations specific to a natural gas distribution utility.[28]

Mr. Coyne and Dr. Booth also looked at a set of Canadian companies as comparators although they recognized the Canadian comparators were mainly holding companies and not directly comparable to FEI in terms of their business functions.

Details of the assessment and use of the comparators proxy companies are set out in Section 5.

Separate from the use of the Canadian and US proxy companies that were inputs into the assessment of an appropriate ROE, Mr. Coyne and Dr. Booth also provided evidence on the approved equity structures and ROE's of gas distribution utilities in other Canadian jurisdictions and how these awarded capital structures relate to FEI's circumstances. This assessment of how FEI compares to the allowed common equity component of other regulated utilities in Canada is included in Section 4.3.3.

4.0 CAPITAL STRUCTURE

4.1 Assessing business risks

In the 2013 GCOC Decision, risk was viewed "as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations."[29] None of the parties in this proceeding raised any issue or provided any alternative to how risk had been defined in past Commission decisions. Therefore, the

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[27] FEI Reply Submission, pp. 13–14.
[28] Oral Hearing Transcript Volume 3, pp. 581–595; FEI Final Submission p. 77.
[29] 2013 GCOC Decision, p. 24.

Panel will continue to rely on this description of risk in its review of FEI's risk profile and its determinations on capital structure.

4.1.1 Establishing a framework for assessing risk

In the 2013 GCOC Decision, the Commission explained that inherent in its definition of risk is the recognition there is the risk of potential financial disruption and therefore accepted the distinction made in previous decisions where investment risk comprised business, financial and regulatory risks.[30]

According to Mr. Coyne, the purpose of his testimony related to FEI's risks was to examine FEI's risk profile in comparison to its peers within the context of FEI's request for a 40 percent equity component. Mr. Coyne asserts that risk for utilities or any company comes from two primary sources, business risk and financial risk. He describes business risk as being inherent in a company's operations regardless of how it is financed while financial risk is a function of the extent to which a company incurs fixed obligations in the financing of its operations.[31]

Dr. Booth provides commentary related to the establishment of a framework for assessing risk. Dr. Booth judges the best way to determine capital structure is to assess it based on the business risk of a utility and cites examples of other Canadian jurisdictions relying on this methodology. He states that a utility "with higher business risk should then have more common equity, so that less financial risk offsets higher business risk to equalize total risk" allowing a regulator to award the same allowed ROE from a generic cost of capital proceeding. Dr. Booth does acknowledge however, that there are cases where an adjustment to both the common equity ratio and the ROE is necessary, particularly in those cases where an inefficient capital structure has resulted.[32]

While it has been common practice in the Commission's cost of capital decisions to consider the common equity ratio and ROE at the same time and not uncommon for a decision to result in a change to both components, it is acknowledged that capital structure and cost of equity are not independent but closely linked to one another. The Panel sees no need to move away from past practice in this proceeding and notes there has been no strong argument from the parties to do so. Therefore, consistent with past practice, the Panel has reviewed the evidence and provided its determination on the common equity component with consideration of three factors: (i) changes in FEI's business risk since the last proceeding; (ii) financial implications related to the potential for credit ratings adjustments; and/or (iii) failure to meet the trust indenture issuance test. In addition, the Panel will also examine and address FEI's level of risk relative to other Canadian utilities.

Prior to examining any potential changes in risk since the 2013 GCOC Decision, the Panel will address two factors that have arisen during this proceeding, each of which provide context to risk related issues to be examined. They are as follows:

- Short-term versus long-term risk of earning the allowed ROE; and
- The impact of amalgamation on FEI's overall risk.

[30] 2013 GCOC Decision, p. 24.
[31] Exhibit B-1, Appendix B, p. 61.
[32] Exhibit C7-7-2, p. 64.

4.1.2 Short-term versus long-term risk of earning the allowed ROE

The impact of short-term risk on overall risk, and whether a short-term risk if never realized over a period of time should be considered a long-term risk and evaluated as such was raised by the parties. Specifically, this issue related to FEI's history of achieving actual earnings higher than its allowed ROE and whether the risk of not earning the allowed ROE should be considered a risk at all when viewed in the context of FEI's historical ROE performance.

Mr. Coyne explains that business and financial risks also have a time dimension and both long and short-term risks are considered by investors and affect a utility's business risk profile. He describes short-term risks as those that will reverse and resolve themselves within a one to two year period through either the normal ebb or flow of earnings or through regulatory relief as a utility's short-term risk. Examples of these could include weather events or financial market disruptions. By contrast, longer term risks are those characterized by a business profile shift where mitigation is not foreseeable. Included among his examples of long-term risk is the risk of stranded assets because of market share losses or changes in environmental policies with a substantial impact on operational profitability.[33]

Dr. Booth describes the ability to earn the allowed ROE, reflecting a return on capital, as short-run risk. The return of capital is a long-run risk reflecting the utility's ability to recover its investment in plant and equipment. Dr. Booth asserts however, that to have any impact, long-term risks must eventually become short-term risks and states that: "To all intents and purposes FEI's shareholders have not suffered any losses or experienced any risk." Further, when such serious risks do arise, Canadian utilities typically come before the regulator for a reallocation of costs.[34] Further, AMPC/BCOAPO, with reference to the earning of ROE, explain neither they nor Dr. Booth take issue with FEI's position that the ability to earn ROE in a particular test year represents short-term risk. However, they contend that year after year "FEI continues to face very little short-run risk, such that this pattern of consistent overearning is clearly a long-term phenomenon" and pose the question as to how many years of persistent over-earning does it take for a utility witness to accept the limited risk faced by utility investors.[35]

CEC takes issue with FEI's statement that risk factors impairing the ability of shareholders to recover their invested capital present risks today are considered by investors in making investment decisions. CEC submits that stock equity investors are more concerned with immediate risk and current ROE performance and assert "investors are free to alter their investment at any time if immediate rewards do not match the immediate risk." Moreover, its view is that risks five years in the future will likely already be reflected in the ROE at the time and therefore recommends greater weight be placed on short-term risks.[36]

FEI submits there are two problems with Dr. Booth's position that FEI's history of earning its ROE suggests FEI experienced no risk. First, risk is prospective in nature and FEI benefiting from sound management and executive oversight generally expects to earn its allowed ROE while at the same time acknowledging that variances still occur due to the imprecision inherent in forecasts and circumstances that arise during a test year. Its ability to

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[33] Exhibit B-1, Appendix B, p. 61.
[34] Exhibit C7-7-2, pp. 64–65, 69.
[35] AMPC/BCOAPO Final Submission, pp. 18–19.
[36] CEC Final Submission, pp. 59–60.

earn its current allowed ROE provides insight only into how the utility manages its short-term risk. A second problem with Dr. Booth's assertion is the full recovery of invested capital in the future is not guaranteed by a utility's ability to manage its budget within a test year. FEI's position is that investors require risks to be compensated throughout the investment period and would not accept that risks should be considered only when it materializes in earnings.[37]

FEI states that CEC's observation that utilities are "free to alter their investment at any time" is flawed. FEI's investment in long-term assets are subject to statutory obligations concerning safe and reliable service and because of this, the law requires the regulator to meet the comparable investment requirement part of the Fair Return Standard. In addition, no investor would accept the argument that compensation is required only for risks that have materialized.[38]

Commission determination

In the 2013 GCOC Decision, the Commission addressed the relevance of the disparity between allowed and actual ROE stating "the differences in actual and allowed ROE relate to revenue requirements and are influenced by management's ability first to forecast and then to control cost for each test period." The Commission also observed that the relevance of a disparity between allowed and actual ROE is a matter that is "entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach."[39]

AMPC/BCOAPO take issue with FEI's position that in a given test year, the ability of a company to earn its ROE is short-term risk. Their collective concern seems to be with the fact that historically, FEI has managed to make and exceed its allowed ROE on a relatively consistent basis and at some point, the risk must be considered very limited or in Dr. Booth's words: "FEI's shareholders have not suffered any losses or experienced any risk."

AMPC/BCOAPO's position is for a risk to remain a risk, it must at some point occur. The Panel is not persuaded that this interpretation of risk is reasonable or reflective of the prospective nature of risk. In the Panel's view, a risk does not disappear because it has not occurred over a period of time and non-occurrence of a risk in the past does not necessarily alter the probability of occurrence in the future.

The Panel does not agree with CEC's assertion that equity investors are concerned primarily with immediate risk and current ROE performance as they can alter their investment when rewards fail to match the immediate risk. While investors certainly consider a risk which has recently occurred, they must be equally concerned about the future prospects of an investment. Further, while it is true investors may sell a particular investment; it would be imprudent of an investor to fail to consider the future prospects of an investment and any potential future risks which may occur.

The Panel accepts FEI's argument that risk is prospective. In the Panel's view, the risk of earning ROE does not disappear in any given test year because of a utility's success in achieving it in prior years. However, this does not mean that an investor does not consider historical performance when choosing to make an investment but in doing so must accept that there is no certainty that past performance will be repeated in the future. Given

[37] FEI Final Submission, p. 51.
[38] FEI Reply Submission, p. 36.
[39] 2013 GCOC Decision, p. 23.

this, we agree with the parties and consider the attainment of ROE to be a short-term risk and if FEI fails to earn its approved ROE in a given test period, it has the capability to initiate actions to resolve the matter in a short time span.

A second issue is whether there has been a change in FEI's ability to earn its ROE in a given year as compared to the period preceding the 2013 GCOC Decision. In the view of the Panel, there is no evidence to suggest there has been a change in this regard. FEI has historically been able, in most circumstances, to earn its ROE in a given test year and none of the parties have taken the position this is likely to change in the foreseeable future. Therefore, **the Panel finds the short-term risk of FEI earning its ROE to be similar to 2013.**

4.1.3 Impact of amalgamation

A noteworthy change that has occurred since the 2013 GCOC Decision is the amalgamation of FEI with FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) that was approved by the Commission on February 26, 2014 by Order G-21-14. This was consented to by the Lieutenant Governor in Council who thereby issued Order in Council No. 300. On December 31, 2014, the three companies amalgamated and are now collectively referred to as FEI. The issue to be considered in this proceeding is whether there has been a material difference in the level of risk assumed by FEI as a result of amalgamation or whether FEI's overall risk has remained unchanged from the period prior to amalgamation.

FEI points out that at the time of the amalgamation, both FEVI and FEW, as a result of the 2014 GCOC Stage 2 Decision had been granted a higher equity ratio and ROE than FEI reflecting the relatively higher business risk of the two entities.[40] However, in this same decision, the Commission stated that once amalgamation was in place and postage stamp rates implemented, the ROE and capital structure for the amalgamated entity would be the same as for FEI. The Commission continued by stating that if the cost of capital was not considered by the amalgamated entity to be indicative of current circumstances, it could make further application to the Commission as the amalgamated entity.

FEI states amalgamation as a factor affects FEI's business risk but is not the principal reason for FEI seeking an increase to either its ROE or common equity component. FEI remains a large natural gas distribution utility and many of the challenges of declining use per customer and low customer growth remain as existed pre-amalgamation. However, FEI does assert that as a result of the addition of these two new territories, there has been increased supply interruption risk related to its dependency on a single pipeline system traversing challenging terrain resulting in greater supply risk. As a result, the amalgamated FEI has exposure to factors resulting from amalgamation that contribute to "a slight increase in overall business risk."[41]

Mr. Coyne notes that FEI has increased its size since amalgamation but, because it was already a large gas distributer, the increase in size has no impact on its risk profile. He also points out that the transitional effects of amalgamation provide help to FEI's risk profile in the short term. Even considering the benefit of higher returns from FEVI and FEW, this does not raise FEI's credit metrics to a level where they fall within Moody's Investor

[40] British Columbia Utilities Commission Generic Cost of Capital, Stage 2 (2014 GCOC), Decision dated March 25, 2014.
[41] Exhibit B-1, pp. 2–3; Exhibit B-1, Appendix C, p. 1.

Services (Moody's) guidelines for the A rating category. The effect of amalgamation is a reduction in FEI's credit metrics, other factors being equal.[42]

Dr. Booth's assessment of the impact of amalgamation does not differ significantly from those of FEI or Mr. Coyne. In Dr. Booth's judgement, the amalgamation of FEI has not materially altered its risk or financial parameters. He recommends no adjustment in consideration of amalgamation noting this conclusion is in line with rating agency decisions which regard amalgamation as not material.[43]

Commission determination

The Panel has determined that the impact of amalgamation for the purposes of assessing FEI's business risk in this proceeding is minimal and has not resulted in any material change to FEI's business risk profile.

Based on the submissions of FEI and the expert witnesses, the Panel notes there is little disagreement among the parties that the impact of amalgamation on business risk is not significant. FEI states it has considered the extent to which its risk profile has changed as a result of amalgamation and describes the change to business risk as being slight. In addition, neither Mr. Coyne nor Dr. Booth makes a case for any significant change in risk resulting from amalgamation and the interveners made no comments in their submissions. Therefore, based on the evidence presented, there is little to justify that amalgamation has had any material effect on FEI's risk profile.

The Panel notes FEI has described the factors resulting from amalgamation that are primarily related to a single pipeline system over difficult terrain as resulting in a slight increase in overall risk but has not explored this issue in any depth. The Panel also notes that FEI focused no attention on the potential positive impact of amalgamation over time. A key element of the Commission decision on amalgamation was tied to moving ahead with postage stamp pricing where rates for most British Columbians will be common. This represents a significant improvement in the former FEVI and FEW customer rates while the impact on FEI's pre-amalgamation customers will be relatively modest. Over time, this has the potential to significantly improve the uptake and use of natural gas on Vancouver Island and Whistler and along with it, FEI's credit metrics, overall profitability and potentially, its risk profile. While not being a factor presently, the Panel considers this as an issue worthy of further examination in future proceedings.

4.2 Assessment of FEI's business risks

4.2.1 Background

An assessment of the level of business risk is a key element in reaching a determination on a common equity component for FEI's capital structure. The Commission has typically found the level of business and other risks are an important factor in determining the equity ratio in a utility's capital structure. In the 2013 GCOC Decision, the Commission determined an appropriate equity thickness for the benchmark utility was 38.5 percent which is 1.5 percent lower than the amount awarded in the 2009 TGI ROE Decision. The determination reached in the 2013 GCOC Decision was heavily influenced by the Commission's finding that there were a number of key risk

[42] Exhibit B-1, Appendix B, pp. 96, 99.
[43] Exhibit C7-7-2, p. 2.

areas where the level of risk had been reduced since 2009 therefore warranting a reduction in the common equity component.

FEI states that utilities are large consumers of equity and debt capital and the financial analyst community for equity investors and the credit rating agencies for debt holders carefully watch and thoroughly scrutinize its fundamentals. Credit rating agencies are particularly sensitive to the cash generated by approved returns to ensure that the interest on its debt can be serviced and the common equity proportion of a utility's capital structure as it provides security for lenders. FEI asserts that its common equity ratio should be increased to 40 percent because of the combination of what it refers to as an "upward trend" in business risk and relatively weak financial metrics.[44]

4.2.2 2016 assessment of business risks

FEI has identified eight risk areas as follows: regulatory risk, market shift risk, political risk, energy price risk, business profile, economic conditions, operating risk and energy supply risk. FEI notes that other risk factors are possible or could be captured differently, but states that relying on the same categories as used in the 2012 GCOC proceeding facilitates comparison of FEI's amalgamated risk profile since the categories are common to all three amalgamated entities.[45] FEI has summarized these business risks in comparison to the 2012 benchmark utility in Table 4.1 and ranked the importance of each.

[44] Exhibit B-1, p. 17.
[45] Exhibit B-1, Appendix C, p. 2.

Table 4.1: Change in Business Risk since 2012 and Business Risk Ranking[46]

Business Risk Category	Risk Factor	Total risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Regulatory		**Same**		**1**
	Regulatory uncertainty and lag	Same	Same	
	Deferral accounting	Same	Same	
	Administrative penalties	Same	Same	
Energy Prices		**Same**		**2**
	Commodity prices	Lower	Same	
	Commodity price volatility	Higher	Same	
	Upfront and installation costs	Same	Same	
Market Shifts		**Same**		**2**
	New technology and energy forms	Same	Same	
	Perception of energy	Same	Same	
	Housing types	Same	Same	
	Changes in use per customer	Same	Same	
	Changes in the capture rates	Same	Same	
Political		**Higher**		**2**
	Energy policy and legislation	Same	Same	
	GHG emissions reductions initiatives and local governments policies	Higher	Same	
	Carbon tax	Same	Same	
	Aboriginal rights	Higher	Same	
Business Profile		**Same**		**2**
	Type and size of the utility	Same	Same	
	Energy product offering	Same	Same	
	Service area and customer profile	Same	Same	
Economic Conditions		**Same**		**2**
	Overall economic conditions	Same	Same	

Business Risk Category	Risk Factor	Total risk status since 2012, (all business changes incl. amalg.)	Risk status change due to amalgamation alone	Ranking of risk
Operating		**Same**		**3**
	Infrastructure integrity	Same	Same	
	Third party damages	Same	Same	
	Unexpected events	Same	Same	
Energy Supply		**Higher**		**4**
	Availability of supply	Same	Same	
	Security of supply	Higher	Higher	

FEI states that independent of the effect of amalgamation, FEI's business risk is "broadly similar" to what it was in 2012 but there are some differences that indicate there is somewhat higher business risk than what was reflected in the approved capital structure and ROE resulting from the 2013 GCOC Decision. Most notable among these is political risk where FEI has identified "GHG emission reduction initiatives and local government policies" and aboriginal rights as areas of increased risk. In addition to this, FEI has identified "commodity price

[46] Ibid., pp. 3–4.

volatility” (Energy Price Risk) and “security of supply” (Energy Supply Risk) and potential impacts related to Performance Based Rate-making (PBR) as areas where risk is higher or has the potential to be higher over the next period of time.[47] FEI identifies no areas where risk has been reduced since 2012.

Interveners are in general agreement with FEI on a number of risk areas where there has been little or no change since the last proceeding. Consequently, their submissions include minimal commentary on items such as market shift risk, business profile, economic conditions and operating risk. However, there is significant disagreement between the parties with respect to other risk categories. Both AMPC/BCOAPO and CEC disagree with FEI’s stance on increased political risk as well as the impact of PBR on regulatory risk. In addition, the interveners have a different perspective than FEI concerning whether energy supply risk is slightly elevated as claimed by FEI or reduced somewhat. Finally, both AMPC/BCOAPO and CEC take the position that energy price risk is much lower due to current low energy price levels. This is in contrast to FEI’s claim they are similar and overall energy price risk is elevated due to increased volatility.

This decision first addresses those categories and related issues where there is disagreement among the parties. These include the following:

- Regulatory Risk – Does the introduction of PBR materially increase risk?
- Political Risk – Do recent provincial and municipal activities concerning greenhouse gas (GHG) emissions reduction and municipal policies mean there has been an increase in overall political risk?
- Political Risk – Do recent First Nations-related court decisions mean that FEI faces greater risk?
- Energy Price Risk – Has continued downward movement in gas prices relative to electricity resulted in less risk to FEI?
- Energy Supply Risk – Has there been any material change in energy supply risk to FEI?

Following our review of the more controversial issues raised by the parties, the Panel briefly discusses the less controversial risk categories where there is general agreement among the parties concerning the lack of change in risk relative to the period dealt with in the 2013 GCOC Decision.

4.2.3 Key differences in views related to FEI’s business risks

4.2.3.1 Impact of PBR

Mr. Coyne’s evidence is that PBR is generally regarded as higher risk than cost of service regulation, a view FEI states is shared by the rating agencies.[48] Mr. Coyne states that although the specific PBR plan includes some moderating features, “the utility remains subject to the risk the formulaic PBR rates may diverge from just and reasonable rates if, for example productivity gains are not realized.” Overall, Mr. Coyne states he considers the PBR to have very little risk in the near term but in later years “the Company will be harder pressed to find productivity gains under the Plan and earnings will be exposed to greater risk.”[49]

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[47] Exhibit B-1, pp. 12–14; Exhibit B-1, Appendix C, Tab 2, pp. 4–6.
[48] Oral Hearing Transcript Volume 2, p. 347; FEI Final Submission, p. 50.
[49] Exhibit B-1, Appendix B, pp. 74–76.

FEI submits there may be an increase in regulatory risk over the PBR term resulting from the potential of being unable to recover prudently incurred costs for exogenous events as a result of the PBR's materiality threshold or if the formula does not adequately compensate FEI for its capital expenditures. In addition, FEI notes the regulatory framework for the period following PBR has not been determined and remains unknown.[50] Also in its submission, the risk presented by PBR is a function of its design and some of the terms will pose greater risk as FEI moves through the PBR term.[51]

Intervener submissions

CEC submits that Mr. Coyne has placed too much emphasis on PBR risks and has not provided any commentary on the opportunities afforded by the model. It is CEC's position that PBR offers an upside potential which is at least equivalent to any additional risks. Further, CEC points out that Mr. Coyne under cross examination acknowledged that FEI has been able to earn its approved return and in many cases exceed it during periods when FEI has been under a PBR Plan and Mr. Coyne also acknowledges cost of service rate plans can be more risky than PBR. In addition, FEI has availed itself of the opportunity to earn above the allowed ROE under PBR and its history of overearning its ROE and the fact that it has a safeguard allowing it to exit the PBR framework eliminates any risk that could be ascribed to the approved PBR model. CEC also notes that the PBR model allows for relief from unexpected events where there are extraordinary situations.[52]

FEI reply submission

FEI also submits that the risk presented by PBR is a function of its design and some of the PBR terms will prove more challenging towards the end of PBR. FEI explains this is because there is potential for greater risk as it moves through the PBR term.[53]

Commission determination

The Panel is not persuaded by FEI's analysis that being under the current PBR plan contributes to increased regulatory risk over the longer term. **The Panel finds that business risk related to the introduction of PBR in this jurisdiction has not increased when compared with cost of service and may potentially offer FEI a greater opportunity for earnings during the PBR period.**

Mr. Coyne makes the assertion that FEI, over time, will be harder pressed to find productivity gains under PBR thereby exposing its earnings to greater risk. However, PBR as approved by the Commission is designed to allow productivity savings, once in place, to continue to benefit FEI for the entire PBR term. Thus, if FEI is able to make adjustments resulting in productivity gains early in the PBR period, it will continue to derive benefits from these changes for the term remaining under PBR. This offers FEI an incentive to establish their productivity gains early in the PBR term thereby maximizing the benefits accruing over the PBR period. Given that FEI has enjoyed an ROE in excess of the allowed ROE base in the first two years of PBR, it can expect to continue to benefit from these savings initiatives for the remainder of the PBR term assuming the productivity improvements continue.[54] Under a cost of service plan typically covering a one to three year period, the utility benefits from productivity

[50] FEI Final Submission, p. 50.
[51] FEI Reply Submission, pp. 32–33.
[52] CEC Final Submission, pp. 108–109.
[53] FEI Reply Submission, pp. 32–33.
[54] FEI Application for Approval of 2015 Delivery Rates pursuant to the Multi-Year Performance Based Ratemaking Plan approved for 2014 through 2019 by Order G-138-14, Exhibit B-1, p. 4; FEI Annual Review of 2016 Delivery Rates, Exhibit B-1, p. 4.

savings only to the end of that period. In the view of the Panel, this seems to favour FEI continuing to earn its ROE rather than presenting additional risk as implied by the comments made by Mr. Coyne.

FEI raises a concern as to the formula not adequately compensating FEI for its capital expenditures. The Panel notes a feature of PBR is the inclusion of a dead band which allows FEI to apply to rebase its capital expenditures covered by the PBR in the event actual costs exceed formula generated costs cumulatively over two years by greater than 15 percent or 10 percent in a single year.[55] The Panel acknowledges this PBR feature does not mitigate the risk of FEI exceeding its formula-driven capital expenditure limit in any given year but it does limit the impact on FEI's ROE.

With respect to FEI's ability to recover prudently incurred costs for exogenous events that fall under the materiality threshold, the Panel notes that a similar risk exists under cost of service where the materiality threshold may be applied but is not explicitly laid out. Therefore, if an exogenous event were to occur, the utility could seek relief by application to the Commission but the outcome would nonetheless remain at risk.

Given these circumstances, the Panel does not agree with FEI that there is increased material risk due to PBR. In the Panel's view, the existence of PBR is as likely to reduce risk as to increase it as FEI has control over its expense load and by its own acknowledgement has a proven ability to effectively manage its costs.

4.2.3.2 Political risk – recent provincial and municipal activities

FEI argues there are developments at all levels of government (municipal and provincial) that suggest a sharper upward trend in its political risk since 2012.

i) Local governments

FEI asserts that the willingness of local governments to dictate energy choices represents a material increase in risk for FEI. FEI asserts that municipalities have been making significant changes to their operations, policy, codes and regulations which are having a direct negative impact on natural gas throughput. Much of this issue concerns the City of Vancouver (COV), which represents approximately 13 percent of FEI's 2016 forecast load, but it is not restricted to that location. Some examples of changes in municipal operations, codes, policy and regulations are as follows:

- A requirement in COV that all new larger buildings be designed to strict energy standards with an energy reduction of 20 percent below 2007 levels by 2020 and carbon neutral by 2030.
- A requirement in COV that new one and two family homes include a number of sustainable features that focus on creating energy savings of up to 33 percent by 2020. Recent bylaw amendments mandate for boiler or furnace upgrades of over $5,000, the annual fuel utilization efficiency be equal or exceed 90 percent.
- Recent Richmond bylaws require new townhomes be designed to score 82 or higher on the EnerGuide Rating System and be solar hot water ready.

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[55] FortisBC Energy Inc. and FortisBC Inc. Multi-Year Performance Based Ratemaking Plans for 2014 through 2019 Approved by Decisions and Orders G-138-14 and G-139-14 Capital Exclusion Criteria under PBR, Order G-120-15 with Reasons for Decision, pp. 16–17.

FEI states similar programs can be found in most municipalities that signed the Climate Action Charter. Specifically, FEI expresses concern with the COV's recent steps to endorse Creative Energy Vancouver Platforms Inc.'s Northeast False Creek and Chinatown projects with exclusive franchise for all space and water heating as a part of COV's Neighbourhood Energy Strategy. This will involve a mandatory connection obligation for developers and prevent FEI from competing for this future load. FEI's estimate is that the Neighbourhood Energy Strategy will represent an annual load of 10.5 PJ or 5 percent of its annual load. However, FEI does not suggest that this amount will be immediately lost and it has no growth forecasts for these areas or forecasts of the rate of redevelopment.[56]

ii) Provincial government policies and legislation

FEI states since the 2012 GCOC proceeding, the provincial government has introduced three minor modifications to existing regulations and has issued a special direction to the Commission for the development of liquefied natural gas (LNG) facilities. FEI acknowledges that these do not represent a change in policy since the last proceeding but note that the provincial emission reduction targets put in place in BC has a disproportionate effect on BC natural gas facilities.[57]

Of some concern to FEI is the fact the BC government has recently announced its plans to build on the success its 2008 Climate Action Plan by developing a new Climate Leadership Plan. While only in the initial development stage, this initiative does increase uncertainty. Further, a Climate Leadership Team has been formed which has recently submitted a series of recommendations to government. These include the following:

- A new GHG emissions reduction target from 2007 of 40 percent.
- The establishment of sectorial GHG reduction goals for 2030 (i.e. 50 percent for built environment and 30 percent for industrial sector focusing on the gas industry).
- An increase in the carbon tax.

FEI acknowledges the Climate Action Team recommendations would have greater weight in an investor's deliberations if they were already adopted. Nonetheless, FEI considers it appropriate for the Commission to consider this uncertainty in its deliberations.

FEI also points out the federal government's recent actions have confirmed Canada's intentions to pursue carbon emission reduction and climate change mitigation initiatives but again, there is nothing firm at this time.[58]

Mr. Coyne's opinion is the risks posed by initiatives undertaken at the provincial and municipal level remain "and are aggressive both in a Canadian and North American context."[59] Mr. Coyne makes no comments as to how these risks compare to what existed during the 2012 GCOC proceeding.

Dr. Booth states that many parties accept natural gas as a solution to the GHG problem pointing to a Canadian Gas Association study which shows even with continued expansion of the natural gas distribution system, GHGs

[56] Exhibit B-1, Appendix C, pp. 64–69; Exhibit B-4, CEC IR 44.1.
[57] Exhibit B-1, Appendix C, Tab 9, pp. 59–63.
[58] FEI Final Submission, p. 49; Exhibit B-4, CEC IR 45.1; Exhibit B-9, BCUC IR 51.1.
[59] Exhibit B-1, Appendix B, pp. 76–77.

are declining. This means the distribution system itself is getting cleaner. Dr. Booth does not see there being a requirement from the provincial government for residential users to modify their use of natural gas for space heating and replace them with more expensive electricity. If FEI does see such a consequence, Dr. Booth believes the correct response will be to perform a depreciation study and depreciate the assets more quickly to reduce any stranded risk thereby keeping FEI whole in terms of risk exposure. In conclusion, Dr. Booth's judgement is that FEI faces lower risk than in 2012 and there is no basis for concluding that its risk has increased.[60]

FEI argues that Dr. Booth's position concerning parties accepting natural gas as a solution to the GHG problem is counterintuitive in the context of a BC utility, makes more sense where natural gas is a clean alternative to coal, and ignores the evidence of local and provincial government action in British Columbia. Further, Dr. Booth's evidence on GHG emissions is based on Canada-wide statistics and not limited to BC and should not be given any weight in light of the limited applicability to this province.[61]

Intervener submissions

AMPC/BCOAPO accept there will be efforts to reduce GHGs over time but argues these will not affect FEI's ability to earn its return on or of its capital. AMPC/BCOAPO also acknowledge district energy systems may limit FEI's future growth in some areas (noting multi-family dwellings) but argue that this does not impact FEI's ability to be competitive. They assert that all the evidence supports natural gas remaining very competitive in its key residential market. AMPC/BCOAPO submit this offsets the price impact from future carbon policies and in addition, notes FEI has not been discouraged from undertaking a large capex program in spite of these policies.[62]

CEC submits that climate change is a real and emerging risk issue for FEI but points out there is an absence of a long-term resource plan outlining the nature of such risk and possible responses. In addition, CEC notes the BC provincial government removed a number of capital investment decisions involving LNG plant expansion and Natural Gas for Transportation (NGT) subsidies from the Commission and the Commission needs to be careful and not assume a risk that has not yet emerged with significant impact.

CEC agrees the mandatory connections in District Energy Systems pose an unrealized risk to FEI and submits the Commission needs to assess the likelihood of such scenarios proliferating in the future. CEC further agrees that there has been an increase in the intensity of local government green initiatives that may contribute to FEI's political risk. However, CEC tempers these comments by stating it is important to bear in mind that there is a 35-year time frame in the COV Neighbourhood Energy Strategy plan.[63]

ICG states there is no evidence local government green initiatives have significantly impacted FEI's operations and no material change to throughput can be attributed to municipally owned district energy systems. In addition, ICG asserts the steps taken by the COV are not recent and FEI was aware that both COV and local governments were considering the use of mandatory connections in 2012. ICG also asserts COV was considering the use of an investor owned utility prior to 2012.[64]

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[60] Exhibit C7-7-2, pp. 79–80.
[61] FEI Final Submission, pp. 53–54.
[62] AMPC/BCOAPO Final Submission, p. 32.
[63] CEC Final Submission, pp. 111–113.
[64] ICG Final Submission, pp. 1–2.

More broadly, ICG states that there is no evidence from which the Commission can assess the effect or potential effect of mandatory connections and exclusivity of end-use requirements. It also states the actual implementation of local government policies related to mandatory connections may increase the risks facing FEI but there is insufficient evidence to conclude such policies have affected the cost of capital as FEI had not provided the cost competitiveness of natural gas energy sources.[65]

FEI reply submission

FEI acknowledges what it considers to be CEC's supportive comments but takes issue with CEC's comments regarding a 35-year timeline and its tempering effect on FEI's experiencing a less supportive environment. FEI agrees that the 35-year period is legitimate but the typical life of distribution assets is longer than 35 years and it must still invest to maintain safe and reliable service. Moreover, FEI notes that CEC concedes there are more immediate impacts associated with mandatory connection policies. FEI concludes by stating, "irrespective of the time frame, it is undeniable that the number of customers and the amount of throughput at issue is very significant."[66]

FEI asserts that AMPC/BCOAPO have avoided discussing new government initiatives at the federal, provincial and municipal level. Additionally, FEI describes AMPC/BCOAPO's comments regarding its capex program as a "red herring" pointing out that most of its expenses primarily serve the export markets and natural gas vehicles and are not related to serving its core heating load. Further, FEI describes AMPC/BCOAPO's comments concerning price competitiveness as being of little assistance when customers desire low carbon district energy or when FEI is prohibited from attaching or serving customers.[67]

Concerning ICG's submissions regarding the timing of the steps taken by the COV, FEI submits the relevant inquiry in this proceeding is how FEI's current business risk was reflected in the Commission's deliberations in the 2012 GCOC proceeding. FEI points out they did not figure prominently in FEI's evidence nor were they commented upon by the Commission in its 2013 GCOC Decision. Further, mandatory connections have become a big issue in recent months and are accompanied by a plan which contemplates ending natural gas consumption in COV, a policy ICG has left unaddressed.[68]

Commission determination

The Panel determines that the level of political risk has slightly increased since the 2013 GCOC Decision.

Based on the evidence, the Panel agrees there is considerably more activity at the municipal and provincial level with respect to climate related initiatives and policies than in the 2012 GCOC proceeding and the subject is more topical than it was at the time of the last hearing. However, as noted, the question the Panel must address is whether there is additional material risk associated with these activities than existed when the 2013 GCOC Decision was made.

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[65] ICG Final Submission, pp. 3–4.
[66] FEI Reply Submission, p. 22.
[67] FEI Reply Submission, p. 23.
[68] FEI Reply Submission, p. 24.

FEI has relied heavily on recent steps taken by municipal governments with respect to policy development and recent activities undertaken at the provincial government level to support its assertion that the level of material risk has increased.

The Panel agrees the recent steps taken by some municipal governments, most notably the COV have the potential to affect the level of future demand and, at least to some extent, pose a threat to FEI's ability to earn a future return on and of its capital. However, the Panel also agrees with AMPC/BCOAPO's assertion that in spite of governmental efforts to reduce GHGs over time, it will not impact FEI's ability to remain competitive, at least in the short to medium term. The key issue is one of timing and the level of knowledge related to potential impacts. Based on the evidence presented, there is only limited knowledge and a great deal of supposition as to how various issues will ultimately be resolved and the timeframes involved. As pointed out by CEC, the Commission needs to bear in mind the COV's Neighbourhood Energy Strategy represents a 35-year time frame. The Panel agrees and understands that over a time period of this length, there is no certainty as to the eventual outcome.

FEI has expressed concern with the government's recent announcement to develop a new Climate Leadership Plan and the team working on this has already made a number of recommendations. FEI acknowledges the recommendations "would have greater weight in an investor's deliberations at present if they were already adopted…" but argues that significant additional investor uncertainty is created by the potential for future political risk. The Panel finds the steps taken by the provincial government to develop a new Climate Leadership Plan pose a potential threat to possible future demand for natural gas but as acknowledged by FEI, none of the recommendations have been adopted and there is no evidence they will be adopted in the near future.

The Panel notes a common way to approach the assessment of risk is to clearly define the situation and the threat that exists and then determine the magnitude of any potential loss resulting from the threat and the probability of it occurring.

FEI has provided a broad description of the threats it believes to exist but has not provided clarity as to the impact or financial loss resulting from these threats. This point is made by ICG who states there is no evidence to support the effect of mandatory connections and exclusivity of end-use requirements. FEI has made assertions with regard to its estimate of the size of load represented by COV's Neighbourhood Energy Strategy. However, FEI acknowledges it is not suggesting this amount will be immediately lost and further reports there are no growth or rate of redevelopment forecasts for the areas covered by the strategy. CEC has agreed that mandatory connections pose an unrealized risk to FEI but notes there is a need for the Commission to assess the likelihood of this proliferating in the future. In the Panel's view, FEI has not addressed this in its evidence.

The lack of detail provided by FEI makes it very difficult to determine the level of risk that exists and its ultimate impact on FEI. Therefore, given the lack of certainty with respect to what lies ahead, the Panel cannot with any degree of confidence, do more than to acknowledge there is a heightened level of potential threats resulting in a slight to moderate increase to the level of political risk when compared to the period around when the 2013 GCOC Decision was rendered. The Panel views the change in the political landscape to be a risk that is evolving and will need to be monitored in future proceedings.

4.2.3.3 Political risk – First Nations

FEI states its ability to construct and operate infrastructure necessary to provide timely service has an influence on attracting and retaining customers. FEI explains that delays in permitting or interference with construction impacts the level of risk to the extent that it discourages new customers or prevents them from serving customers. In consideration of these factors, recent court decisions with respect to First Nations engagement have had a material effect on risk levels as compared to 2012 as they have changed First Nations' and others' ability to influence project implementation and timelines.[69]

Mr. Coyne agrees the presence of 285 different aboriginal First Nations may lead to additional regulatory process. In his view, this impacts FEI's risk profile by adding potential for protracted regulatory or political proceedings.[70]

<u>Intervener submissions</u>

AMPC/BCOAPO state that Terasen Gas Inc. (now FEI) made a similar argument in the 2009 TGI ROE proceeding. In that decision, the Commission noted court decisions post-2005 did constitute an increase in risk over local distribution companies in other provinces, but did not consider that such risk casts doubt on the utility's ability to earn a return on or of its capital. AMPC/BCOAPO argue FEI has made no substantial connection between recent jurisprudence and its operations that raise doubts as to its ability to earn its return. Consequently, the Commission should reject any suggestion this should drive an increased return.[71]

CEC states it agrees that aboriginal rights continue to create uncertainty for businesses operating in BC. However, there is no evidence of a change in risk profile for FEI nor is there evidence suggesting FEI will not continue to manage First Nations relations effectively and efficiently.[72]

<u>FEI reply submission</u>

With reference to AMPC/BCOAPO's submissions, FEI notes that in the 2009 TGI ROE Decision, the Commission's finding stated "presently" the risks did not cast doubt over the utility's ability to earn a return on or of its capital. FEI reaffirms its position that presently there is potential for Aboriginal rights and title issues to impede FEI's ability to add and maintain throughput thereby having the effect of regulatory lag in capital approvals. FEI points out that because AMPC seems to agree that regulatory lag is an accepted risk factor, any lag related to First Nations issues should be viewed in the same light.[73]

Commission determination

The Panel agrees with AMPC/BCOAPO and CEC and finds the evidence is not persuasive that any change in the threat to FEI's operation caused by recent jurisprudence will have a material effect on the utility's ability to earn a return on and of its capital. As noted by CEC, there is no evidence to suggest that FEI will not continue to be successful in managing its relations in an effective and efficient manner. The Panel agrees and notes that FEI has provided no firm evidence as to the probability of project lag or its impact on earning a return.

[69] Exhibit B-1, Appendix C, Tab 9, p. 72; FEI Final Submission, p. 49.
[70] Exhibit B-1, Appendix B, p. 63.
[71] AMPC/BCOAPO Final Submission, pp. 32–33.
[72] CEC Final Submission, p. 113.
[73] FEI Reply Submission, p. 26.

4.2.3.4 Energy price risk

FEI separates the energy price risk category into risk type as follows: natural gas commodity price risk, commodity price volatility risk and the price competitiveness of natural gas (includes upfront and installation costs). FEI's position is collectively, these give rise to a similar level of risk to what existed in 2012.

FEI acknowledges commodity prices are reduced from 2012 but have outlined a number of factors to help explain why the impacts of changes in commodity prices do not translate directly to changes in overall risk. In support of its position, FEI makes the following points:

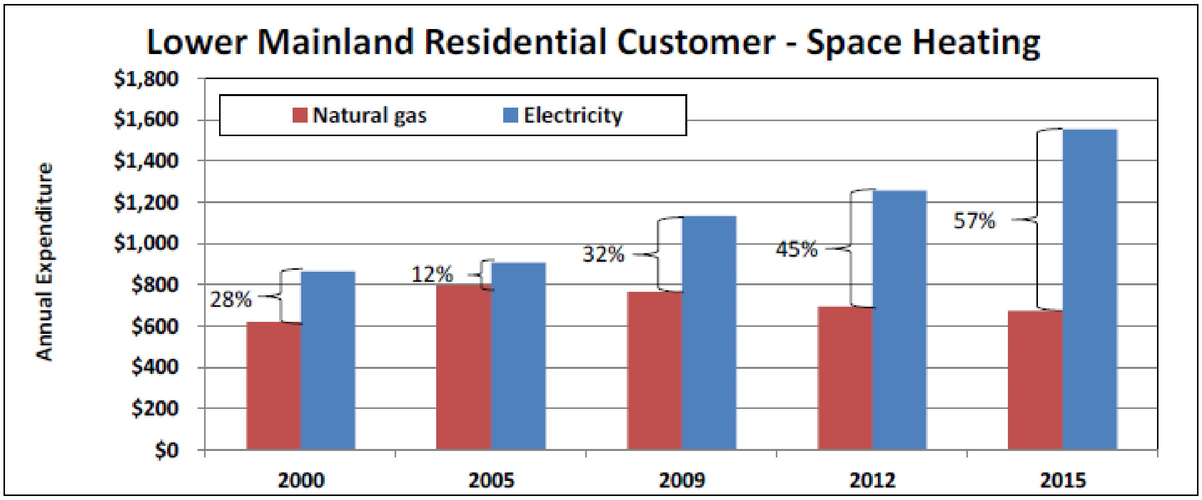
- The capital cost differential between gas and electricity are substantial but developers and builders are the primary decision makers and do not see the operating savings;
- Commodity price volatility has increased since 2012 and while customer rates do not fluctuate with every price change, they remain exposed. In addition to their bills, customers' perceptions are influenced by what they hear on the news; and
- The effect of commodity costs on the total bill is less than in 2012. The commodity prices in 2012 already constituted a small portion of the overall LNG delivered price and therefore, the impact on risk of a price change is in and of itself muted.[74]

<u>Intervener submissions</u>

AMPC/BCOAPO submit that while FEI's bills are similar to five years ago, it does not tell the whole story. AMPC/BCOAPO have identified competitiveness as likely the most important determinant of FEI's business risk and submit that the cost of natural gas by itself tells us little about FEI's competitiveness. The genesis of their position is that energy prices have continued to decrease over the last 10 years yet, customer total billing is similar to what it was five years ago and FEI's rates are now much lower than BC Hydro's. As a result, FEI is in an advantageous competitive position relative to BC Hydro. Figure 4.1 shows the relative cost of natural gas compared to electricity for lower mainland space heating for the period from 2000 through 2015.

[74] Exhibit B-9, BCUC IR 27.1, 27.3; Exhibit B-1, Appendix C, p. 46, pp. 51–56; FEI Final Submission, pp. 42–44.

Figure 4.1: Space Heating Price Comparison[75]



Notes:

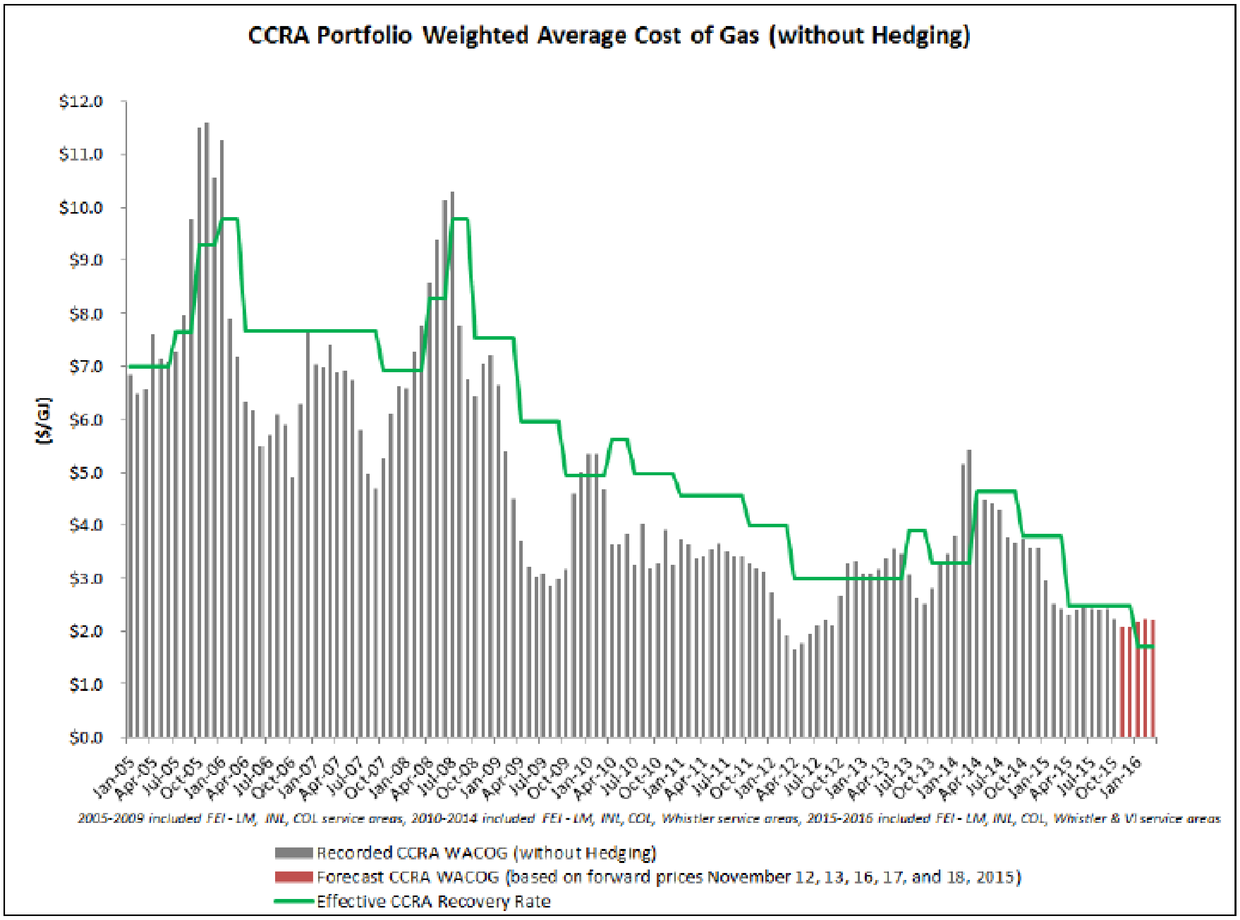
1. Estimated residential bills are based on prevailing rates on July 1 of each specified year with the exception of 2015, where FEI rates are effective August 1, 2015
2. The estimated bills have been calculated by FEI and may differ from actuals

AMPC/BCOAPO point out the evidence shows a positive trend for FEI in its key residential market since 2005 and in the present context, the Commission can definitely conclude gas is more competitive than in its prior reviews. They also point out that in the future, significant electricity rate increases are likely due to anticipated high capital, electricity supply, operating and maintenance costs and large deferral account balances. AMPC/BCOAPO state FEI's competitive advantage over BC Hydro "has increased more since 2012 than it did between 2009 and 2012." Further, they assert this was a key factor in the Commission's 2013 GCOC Decision and suggest "a reduction at least equal to the 1.5 % 2013 reduction in FEI's common equity ratio" in the present circumstance.[76]

Concerning commodity price volatility, AMPC/BCOAPO argue that risk is lower now than in 2013 and reject FEI's claim that risk has increased since 2013. It is AMPC/BCOAPO's position that FEI's evidence, as presented in Figure 4.2, indicates there was high price volatility between 2005 and 2009 and with less volatility since that time.

[75] Exhibit B-7, AMPC IR 2.12.
[76] AMPC/BCOAPO Final Submission, pp. 21–25.

Figure 4.2: Weighted Average Cost of Gas[77]



The most important of these issues to AMPC/BCOAPO is that prices have varied around a lower level. In their view, the likelihood of stable pricing is greater and except for short periods of price disconnects, the risk of dramatically higher natural gas prices remains significantly lower. AMPC/BCOAPO note that consumers might not like significant price volatility, but state it can be assumed in the current low price environment that price fluctuations are less of a deterrent to natural gas use than in the previous high price environment.[78]

CEC makes submissions similar to AMPC/BCOAPO with respect to the competitive pricing advantage FEI has over BC Hydro and does not consider volatility to be an evident concern for customers. CEC submits the overall cost of gas is the most important consideration in customer decision making and recommends the Commission heavily weight the favourable cost of gas and its comparison to electricity and place less weight on the short-term volatility occurrences as it does not affect the customer in any significant way given the current circumstances. Overall, CEC recommends the Commission find “there is no appreciable price risk or volatility risk for natural gas and the overall risk is lower than in 2012 because of prolonged periods of low natural gas prices.”[79]

[77] Exhibit B-9, BCUC IR 27.1.
[78] AMPC/BCOAPO Final Submission, pp. 21–22.
[79] CEC Final Submission, pp. 79–88.

FEI reply submission

FEI contends AMPC/BCOAPO and CEC give insufficient weight to factors that mute the impact of reduced prices on FEI's overall competitiveness. It is the increase in the price of electricity rather than a drop in natural gas prices that is the main contributor to improved price competitiveness and lower commodity costs have not translated into lower natural gas bills. FEI asserts the interveners are glossing over the fact it is the consumer's response to changes in relative cost and not the changes themselves that ultimately impacts the company. Despite improved price competitiveness since 2012, the following has occurred:

- Throughput is lower in 2014 than in 2012.
- Use per Customer continues to trend downward.
- FEI continues to lose market share in core space heating and water heating applications.

FEI explains the weak relationship between price competitiveness and these results as being influenced by the following factors:

1) Demand for natural gas is inelastic where a reduction in cost does not result in a similar change in consumption.
2) Factors such as government policies and consumer attitudes about carbon emissions have contributed to the decoupling of price competitiveness from its key indicators.
3) Higher upfront capital costs related to gas appliances and potential main extension test customer contributions continue to be a barrier for builders or developers adopting natural gas.[80]

Commission determination

Because of the importance placed on it by consumers, the Commission in the 2013 GCOC Decision considered energy price to be a key determinant and deserving of significant weight when considering changes to FEI's risk. In the 2013 GCOC Decision, the Commission found there was some reduction in the level of risk related to natural gas' competitive position relative to electricity. The question in this proceeding, as raised earlier is whether the continued improvement in the price of gas has resulted in any further reduction of FEI's risk.

The evidence is clear and points to the fact that the price of gas continues to drop as compared to electricity. As outlined in Figure 4.1, the annual expenditure price differential for lower mainland space heating has increased from a price advantage of 45 percent favouring natural gas in 2012 to a 57 percent advantage for natural gas in 2015. The Panel acknowledges that on the basis of price, the competitive advantage of natural gas has improved over what existed in 2012. However, we also acknowledge there was a substantial price advantage that existed in 2012 resulting in reduced risk as noted in the 2013 GCOC Decision.

In spite of what is clearly a growing competitive price advantage favouring natural gas, FEI reports that key indicators such as throughput, use per customer and market share of core space and water heating applications remain unfavourable. FEI has explained that inelasticity of demand, government policies and consumer attitudes about carbon emissions and higher upfront capital costs have contributed to the decoupling of price competitiveness from the key indicators. The Panel accepts that these factors may be responsible for decoupling

[80] FEI Reply Submission, pp. 26–27.

but suggest that it is equally plausible other factors such as demand side management and weather have had an impact on FEI's more recent key indicator performance.

The Panel continues to put weight on the importance of a competitive price advantage for natural gas over electricity in determining the level of risk for FEI. Therefore, the fact that the gap between natural gas and electricity continues to widen must be given some weight when determining whether the level of energy risk has changed since the 2012 GCOC proceeding. Tempering this somewhat is the fact that some of FEI's key indicators have continued to lag, in spite of a growing competitive price advantage favouring natural gas. **Taking these factors together, the Panel finds the level of energy price risk to have decreased somewhat when compared against the 2013 GCOC Decision.**

4.2.3.5 Energy supply risk

FEI states the continuity of energy supply risk has also remained unchanged since 2012. However, the amount of gas available to FEI could be altered due to the development of several gas infrastructure projects connecting BC deposits with Alberta and with eastern markets in coming years. FEI states this could ultimately impact what customers pay in the coming years. In addition, FEI notes the addition of FEVI and FEW comes with slightly increased exposure to security of supply risk. This is due to its system crossing radial terrain and the Strait of Georgia as well as the fact Whistler is served by the pipeline lateral between Squamish and Whistler which is subject to single point of failure risk.[81]

Mr. Coyne states the expansion of natural gas fired demand related to the retirement of coal plants along with new LNG exports and potential requirements south of the border could result in a capacity shortage on Spectra's T-South pipeline thereby increasing volatility and commodity prices. While acknowledging pipeline expansions are an option, Mr. Coyne's view is the risks with projected additional gas demand in the Pacific Northwest and BC will continue to grow when considered against the availability of pipeline capacity.[82]

Dr. Booth cites data from Canadian Gas Association (CGA) which in their latest analysis states that Canada has over 200 years supply coverage at current production rates. Dr. Booth comments that with such a plentiful cheap resource to distribute "we should expect an expansion in supply which is what happened as there has been significant expenditure on the distribution system." Citing CGA, he notes that 2014 expenditures on pipeline expansion total $1 billion with a further $2.6 billion in distribution spending. This, he states, indicates the industry does not envision long run market problems.[83]

<u>Intervener submissions</u>

AMPC/BCOAPO submit supply risk has been reduced due to further development and quantification of BC's shale gas resources noting this is confirmed by Nova Gas Transmission Ltd.'s (NGTL) further expansion. AMPC/BCOAPO do not consider the security of natural gas supply to be at issue given its important role in the province's future. Further, they submit the province is committed to development of BC's natural gas resources and state there is "no reason to suggest that appropriate infrastructure will not be extended to a resource located in the Province in order to serve the needs of BC customers when it is needed." Nor is there a reason to

[81] Exhibit B-1, Appendix C, p. 46, pp. 51–56; FEI Final Submission, p. 45.
[82] Exhibit B-1, p. 66.
[83] Exhibit C7-7-2, pp. 70–71.

believe gas price competitiveness will be inadequate to support paying for any needed infrastructure by customers. In AMPC/BCOAPO's view, the importance of security of supply is minor in comparison to availability of supply where there is an abundance of the resource in the ground.

AMPC/BCOAPO also submit that amalgamation has resulted in no change to total supply risk as there is no change in the physical risks the combined operations face.[84]

CEC submits the growing use of pipeline capacity could present supply risks but these risks are not attributable to FEI if the utility has reserved adequate capacity for its customers' needs. CEC points out that Mr. Coyne agrees it is the utility's responsibility to look ahead and contract for access to infrastructure reserve opportunity and FEI has a sophisticated gas purchasing group responsible for this. CEC submits that if FEI conducts appropriate planning activities, it is unlikely there will be a gas supply interruption and the Commission "should find it straight forward to assess that the gas supply risk is unchanged and manageable by FEI in the relevant future for this ROE and CEC determination."[85]

CEC submits the FEI characterization of supply availability risk as being unchanged from 2012 is accurate. It notes FEI has acknowledged that supply interruption risk from FEVI and FEW is marginal and those related to amalgamation are modest. Given the marginal nature of the increase in amalgamation risk and the offsetting reduction in risk for interruption of pipeline supply resulting from the Lower Mainland Intermediate Pressure System Upgrade, CEC submits the Commission should consider this as a net reduction in risk.[86]

FEI reply submission

FEI does not share AMPC/BCOAPO's view that availability of supply risk has declined since 2013. It is FEI's view that the production forecast for the Western Canadian Sedimentary Basin indicates the expected production level is lower in the spring of 2015 than it was in 2012, indicating large shale gas reserves will not result in higher production levels. Additionally, NGTL's proposed extensions could potentially represent a challenge to FEI resulting in lower use of Westcoast's T-North and T-South transmission systems impacting the Station 2 marketplace FEI relies upon for much of its supply requirements.

For clarity, FEI notes its evidence is that the security of supply risk is "slightly increased" because of FEVI and FEW being incorporated into its system and FEI has not characterized supply risk as higher than in 2013 because of factors related to bringing gas from northern BC to its system.

FEI rejects CEC's argument that any increase in amalgamated FEI's security of supply is offset by proposed or approved integrity and sustainment projects pointing to their response to BCUC IR 50.2[87]where it was stated that the projects were needed to operate the gas system in a safe and reliable manner.[88]

[84] AMPC/BCOAPO Final Submission, pp. 29–30.
[85] CEC Final Submission, pp. 67–69.
[86] CEC Final Submission, pp. 71–72.
[87] Exhibit B-10, BCUC IR 50.2.
[88] FEI Reply Submission, pp. 33–35.

Commission determination

The Panel finds there has been no change in the level of risk associated with availability of supply and agrees with FEI that the security of supply risk is slightly increased due to the amalgamation of FEVI and FEW into FEI's system.

The Panel rejects AMPC/BCOAPO's assertion there has been a reduction in risk associated with availability of supply as compared to 2012. In the 2012 GCOC proceeding, adequate supply or availability of gas was not an issue and since that time, there has been no significant change in circumstances. However, the Panel agrees with FEI that there has been some change in the risk associated with security of supply due to amalgamation of FEW and FEVI into FEI. In the 2014 GCOC Stage 2 Decision, the Commission found FEI and FEW had additional supply interruption risk when compared to FEI but described them as marginal. In addition, the Commission found that while the possibility of an event related to difficult terrain may exist, the probability of such an event is very low. The Panel notes there is no evidence in this proceeding to suggest that this risk related to terrain has abated. However, as noted in the 2014 GCOC Stage 2 Decision, the probability of an event is very low and therefore is not considered to be a material increase in risk.

4.2.4 Other risk areas

As outlined earlier in this section, there were a number of risk categories where there was general agreement among the parties there was little change in the level of risk as compared to the period preceding the 2013 GCOC Decision; these include risks associated with operating, market shift, economic conditions and business profile.

Operating risk

Operating risk covers any physical risks to the utility system arising from technical and operational factors which includes items like asset concentration, technologies employed to service, geography in the service area and weather. FEI states that since 2012, there has been no change to the level of operating risk of facilities in the mainland service area. FEI also states the amalgamation of FEI with FEVI and FEW has posed no additional operational risk. FEI has focused its assessment on three areas; infrastructure integrity, third party risks and unexpected events. FEI has assessed its infrastructure integrity and although two-thirds of the current assets will need to be replaced over the next 40 years, acknowledges this was understood in 2012 and the risk remains similar for the amalgamated utility. The incidence of third party damage has been decreasing since 2006 and FEI notes this trend was understood in 2012 and has assessed the risk to the amalgamated utility to be similar to that faced by FEI in 2012. The incidence of natural events is one of the higher operating risks to FEI but remain materially unchanged from what existed in 2012.[89]

Neither AMPC/BCOAPO nor CEC take issue with FEI's assessment of its operational risk and both agreed there was no change since last reviewed in 2012.[90] ICG provided no specific submissions with respect to operating risk.

[89] Exhibit B-1, Appendix C, pp. 57–58.
[90] AMPC/BCOAPO Final Submission, p. 33; CEC Final Submission, p. 66.

Market shift risk

Market shifts in the areas of new technology and energy forms, changing customer perceptions of energy and types of homes being built continue to pose challenges to FEI in terms of its ability to attract and retain customers and maintain its market share and throughput levels. FEI has provided a brief description and update for each of these factors and outlines impacts on use per customer and customer additions. FEI submits each of these areas provide similar risks for FEI at present as has existed in the 2012 GCOC proceeding even when considering the effects of amalgamation.[91]

AMPC/BCOAPO, while finding FEI's use of the term "market shifts" misleading and preferring to use the term "market demand," nonetheless seem to agree with FEI's assessment that there is little change with this risk and notes that the utility's customer profile remains very stable. Likewise, CEC prefers to label this group of risks as volume and demand risk but agrees with FEI that the level of risk is likely to differ little from what existed at the time of the 2013 GCOC proceeding. ICG did not specifically address market shift risk but did submit that the Commission should reject loss of market share as a business risk as there is not enough evidence on the record to reach such a conclusion.[92]

Economic conditions

FEI states that economic conditions have an impact on a utility's ability to attract and retain customers and maintain throughput levels and the current economic environment continues to be dominated by uncertainty. The recent drop in oil prices has had a negative impact on GDP growth but this could be partially mitigated by a weaker Canadian dollar combined with the relatively strong US recovery leading to a potential improvement in exports. Given these circumstances FEI assesses the risk related to economic conditions as similar to what existed at the time of the last proceeding.[93]

As noted in Section 3.2 above, there is little disagreement among the parties that the economic condition on the BC economy is not materially different from the 2012 levels.

Commission determination

The Panel finds there has been no change in the level of risk associated with operating risk, market shift risk or economic conditions as compared to what existed at the time of the 2013 GCOC proceeding. In each of these areas, FEI has assessed the factors related to these risks and concluded there is continuity in the level of risk for each, acknowledging this is also the case when considering any additional impacts caused by amalgamation. Interveners either agreed with or took no issue with FEI's conclusions on these risk areas.

4.3 Other items impacting capital structure

FEI submits, in addition to its level of business risk, the following points support a common equity component of 40 percent for FEI as being consistent with the Fair Return Standard:

[91] Exhibit B-1, Appendix C, pp. 39–50.
[92] AMPC/BCOAPO Final Submission, p. 25; CEC Final Submission, p. 96; ICG Final Submission, p. 3.
[93] Exhibit B-1, Appendix C, p. 15.

- FEI's financial metrics, which reflect its allowed ROE and capital structure, are weak for a credit rating in the "A" category and if FEI was to receive a rating downgrade this could adversely impact both its ability to borrow and the cost of borrowing;
- An increase in its common equity component will support FEI's ongoing debt issuance capacity under the Trust Indenture; and
- A comparison to its peers indicates FEI's proposed common equity component is appropriate, but at the low end of the range of reasonableness.[94]

4.3.1 Credit ratings and access to capital

Moody's July 20, 2015 credit rating on FEI stated:

> FEI's credit quality is driven by its credit supportive regulatory environment and its monopoly position. The company has a long term track record of earning its allowed return on equity and its cash flow continues to be highly predictable. This is offset by the company's weak financial metrics, with limited headroom at the current rating level, that are primarily a product of the allowed return on equity and the equity component of its capital structure.[95]

FEI presents the following table outlining its key financial indicator scores compared to the minimum A3 rating per Moody's utility rating methodology:

Table 4.2: FEI's Credit Metrics from 2011 to 2014[96]

	FEI's Score	A3 - Rating Threshold[24]	2011	2012	2013	2014
CFO pre-WC + Interest / Interest	Ba	4.5x	2.3x	2.5x	2.7x	2.8x
CFO pre-WC / Debt	Baa	19.0%	11.2%	14.5%	15.1%	14.4%
CFO pre-WC - Dividends / Debt	Baa	15.0%	6.6%	9.6%	8.0%	10.3%
Debt / Capitalization[25]	A	50.0%	47.4%	44.0%	43.6%	45.2%

FEI notes that with the exception of its Debt to Capitalization ratio, all of its financial metrics are below the Moody's designated threshold for an A3 rating and are generally weaker than its Canadian peer group.[97]

FEI stated that it has not been rated below A3 since 2011 and in 2013, Moody's changed FEI's credit outlook to negative due to the reduction in ROE and common equity ratio in the 2013 GCOC Decision. FEI also indicated that its Moody's rating was eventually amended back to stable in June 2014.[98]

FEI states that Moody's reaction to the 2013 GCOC Decision highlights the risk to FEI's current rating, which is influenced by FEI's relatively weak credit metrics.[99] However, FEI acknowledged that while credit metrics represent a large weighting of the overall methodology, weak credit metrics can be offset by qualitative factors such as strong regulatory support.[100] Nonetheless, a further weakening of these metrics in connection with an adverse regulatory decision on common equity component or ROE would place downward pressure on the

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[94] FEI Final Submission, p. 56.
[95] Exhibit B-1, Application, Appendix A, Moody's Investor Services, Credit Opinion: FEI (Moody's Credit Opinion), dated July 20, 2015.
[96] Exhibit B-1, p. 25.
[97] Exhibit B-1, p. 25.
[98] Exhibit B-9, BCUC IR 8.1.
[99] Exhibit B-1, pp. 24–25.
[100] Exhibit B-9, BCUC IR 8.3.

rating.[101] FEI points out that according to Moody's July 2015 Credit Opinion, a weakening of credit metrics in connection with a material adverse regulatory decision could result in a rating downgrade.[102]

Mr. Coyne states that since FEI is rated Moody's A3 and this is the lowest rung in the A rating category, FEI's higher capex spending in the near term may result in downward pressure on FEI's credit metrics and could result in a ratings downgrade.[103]

With reference to its July 2015 Credit Opinion, Mr. Coyne notes Moody's assessment states a ratings downgrade is unlikely.[104] However, Moody's opinion indicates there are several factors that could lead to a downgrade including "an unexpected, material adverse regulatory decision or a forecast of a sustained deterioration in credit metrics including CFO/pre-W/C to debt of less than 11%."[105] Moody's currently calculates FEI's March 31, 2016 "CFO/pre-W/C to debt metric at 15.0%."[106]

Mr. Coyne states that a downgrade below an A rating grade is particularly significant in the Canadian credit market due to the following:

- Canada has less trading of debt with a rating below the A ratings grade;
- Institutional investors often face limits investing in Baa/BBB debt; and
- During the financial market dislocation of 2008 and 2009, regulated issuers below an A credit rating, were effectively shut out of the Canadian credit market.

Mr. Coyne also continues that given FEI's expected financing requirements for its large capital projects, a downgrade to below an A rating would result in higher financing costs and "should be avoided."[107] He refers to Moody's most recent credit opinion which states FEI has "limited financial headroom" at the current rating and that large capital projects are expected to place downward pressure on credit metrics in 2015 with improvement forecast as capital projects are completed in 2016 and 2017. In his direct testimony, Mr. Coyne includes a quote from the Moody's July 2015 Credit Opinion which speaks to this. The Panel notes that the last sentence of the paragraph which states that with respect to the downward pressure on credit metrics "this forecasted weakness is incorporated in the current rating"[108] was not included.

Dr. Booth concludes FEI can access the bond market on more favourable terms than in 2013 and in doing so, it will continue to lower its embedded debt cost, increase its interest coverage ratio and enhance its financial flexibility.[109]

Dr. Booth notes "DBRS has long maintained the exact same 'A' rating on FEI and its predecessor companies through periods when it had a 33% common equity ratio, a 35% common equity ratio, a 40% common equity

[101] Exhibit B-9, BCUC IR 9.1.
[102] Exhibit B-1, Application, Appendix A, Moody's Credit Opinion, p. 3; Exhibit B-9, BCUC IR 8.3.
[103] Exhibit B-1, Appendix B, p. 97.
[104] Exhibit B-1, Appendix A, Moody's Credit Opinion, p. 3, the report states that Moody's does not expect the rating to go down.
[105] Exhibit B-1, Appendix A, Moody's Credit Opinion, p. 3.
[106] Exhibit B-1, Appendix B, p. 97.
[107] Exhibit B-1, Appendix B, pp. 97–98.
[108] Exhibit B-1, Appendix A, Moody's Credit Opinion, p. 3.
[109] Exhibit C7-7-2, p. 35.

ratio and most recently a 38.5% common equity ratio."[110] Moreover, he asserts "the guidelines are heavily based on the degree of regulatory protection, where 50% of the weight applied by Moody's is explicitly for this and not the financial metrics. Consequently, the metrics are not the most important issue."[111]

FEI observes that Moody's downgraded FEI's rating from A2 to A3 in 2005 because it considered FEI's financial profile weak relative to global peers and despite receiving increases in ROE and common equity component in subsequent decisions, Moody's has never upgraded FEI's rating back to A2.[112]

FEI submits:

- A combination of financing requirements for capital project, maturity of purchase money mortgages (PMMs) and rising interest rates have the potential to constrain its ability to issue debt under its Trust Indenture at the current common equity ratio. FEI submits that a 40 percent equity ratio will alleviate these factors, and will help to support FEI's credit rating.
- A reduction in allowed common equity, particularly a reduction approaching the levels Dr. Booth has recommended, would have the double impact of constraining debt issuance capacity and making a rating downgrade likely.[113]
- Maintaining an A credit rating is important because the benefits include: a lower cost of borrowing, access to capital markets and credit with FEI's counterparties.
- Maintaining an A credit rating ensures access to the capital markets on reasonable terms and pricing in all market conditions including a market disruption similar to 2008 and 2009. The potential for a market disruption exists despite the current lower interest rate environment.
- Any downgrade of Moody's A3 rating to Baa/BBB category would lead to a split-rating for FEI and result in FEI being considered principally a BBB rated entity thereby having an adverse impact on FEI's cost of debt, access to capital markets and credit with its counterparties.
- A downgrade below an A rating grade is particularly significant in the Canadian credit market where there is less trading of lower-rated investment grade debt.
- A decision to reduce common equity or ROE may be viewed as undermining regulatory support that has otherwise supported FEI's rating in the face of traditionally weak metrics.[114]

Intervener submissions

AMPC/BCOAPO make the following points in their submission:

- It is appropriate FEI be able to maintain its credit and attract capital but FEI should not pay more than necessary to attract capital;
- FEI's present DBRS "A" with a stable trend and Moody's "A3" with a Stable Outlook means FEI's credit metrics are not weak;
- FEI's DBRS credit rating has not changed in a long period of time including during periods when FEI's common equity ratio varied from 33 percent to 35 percent to 40 percent and then 38.5 percent;

[110] Exhibit C7-7-2, p. 81.
[111] Exhibit C7-7-2, p. 82.
[112] Exhibit B-16, p. 9.
[113] FEI Final Submission, p. 4.
[114] FEI Final Submission, pp. 56–58.

- It is not "credible" that FEI's credit rating would change if its common equity ratio is set to the 35 percent it had prior to 2009;
- The Commission can also take note of the Ontario Energy Board's (OEB) recent confirmation of the common equity ratios for Union Gas and Enbridge Gas Distribution Inc. (EGDI) at 36 percent which indicates that there was no concern a 36 percent common equity ratio would put their "A" credit ratings at risk; and
- Nothing in the current market conditions indicate FEI needs any sort adjustment to improve its access to capital markets.[115]

CEC submits that FEI's previous "negative ratings" outlook from both an ROE reduction and equity component reduction did no permanent damage to FEI. CEC also submits the credit metric sensitivities provided by FEI are positive and as a result, there is no compelling evidence upon which to raise FEI's common equity component.[116]

<u>FEI reply submission</u>

FEI submits AMPC/BCOAPO's reference to FEI's maintenance of an A rating when its common equity ratio was 33 percent is for a period 13 years ago and when it had a 35 percent ratio was almost seven years ago. FEI reiterates its view that Moody's June 2013 decision to place FEI on a negative ratings outlook pending further review is a signal that FEI's current rating is not secure.[117]

Commission determination

The Panel agrees maintenance of an A credit rating helps ensure FEI's access to capital in most market conditions, and among other benefits, ensures a lower cost of borrowing. The evidence presented in this proceeding supports FEI's assertion its credit metrics are weak for an A rating, however, at its current ROE and common equity ratio, the rating agencies have offset this weakness in metrics with other factors including a supportive regulatory environment.

The Panel is not persuaded FEI's expected higher capital expenditures through 2017 will in and of itself result in significant downward pressure on its credit rating. Moody's July 2015 credit opinion incorporates the impact of the large capital projects on FEI's credit metrics beginning in 2015 and forecasts improvement as projects are completed in 2016 and 2017. Moody's report indicates "this forecasted weakness is incorporated in the current rating."[118] Moody's report also indicates it does not expect the rating to go down and Mr. Coyne notes in his report that Moody's assessment is that a rating downgrade is unlikely, although it did list some factors that could lead to a downgrade. **Given that Moody's analysis already takes into account the expected capital expenditures with forecast improvements in metrics in 2016 and 2017 and since there is no other evidence forecasting a deterioration in credit metrics, the Panel finds, in the absence of other factors, the expected capital expenditures are unlikely to cause a downgrade in FEI's credit rating at its current equity ratio.**

The Panel accepts FEI's view that a reduction of its common equity ratio, especially to the level recommended by Dr. Booth, could result in downward pressure on the credit rating. Moody's past actions, including its reaction the 2013 GCOC Decision, indicate that any negatively viewed regulatory action could impact FEI's credit rating

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[115] AMPC/BCOAPO Final Submission, pp. 65–67.
[116] CEC Final Submission, pp. 51–53.
[117] FEI Reply Submission, pp. 39–40.
[118] Exhibit B-1, Appendix A, Moody's Credit Opinion, p. 3.

due to its weak metrics especially given the additional pressure higher capital expenditures expected over the next few years. With respect to the AMPC/BCOAPO and CEC submissions related to FEI's ability to maintain its credit rating during periods where it was awarded a lower equity thickness, the Panel agrees with FEI that these instances relate to periods prior to 2009 and are unlikely to be relevant to the current decision.

The Panel agrees with the interveners and finds that there is no compelling evidence to support that an increase in common equity component is required to maintain FEI's current credit rating.

4.3.2 Trust indenture issuance test

With respect to its Trust Indenture, FEI states:

> FEI's Trust Indenture governs FEI's debentures including the ability to issue new debt. The debt issuance coverage test in the Trust Indenture provides that FEI will not issue debentures (other than First Mortgage Bonds or Purchase Money Mortgages (PMMs) (both represent secured debt) maturing 18 months or more after the date of issue) unless Consolidated Available Net Earnings (CANE) is at least 2.0 times the annual interest expense on debentures, excluding interest related to PMMs and including the annual interest requirements on the additional debentures being issued (defined as Interest on Funded Obligations under the Trust Indenture). Formulaically, CANE/Interest on Funded Obligations >=2.0. Failure to meet this test would limit FEI's ability to issue long-term debt.[119]

FEI expects the debt financing requirements related to its capital needs for the 2016 to 2018 period could approach $1 billion. In addition, FEI has $275 million of debt classified as purchase money mortgages (PMMs) which are excluded from the debt issuance coverage test of which $75 million matured in 2015 and $200 million will mature in 2016. FEI states that the maturing PMMs are being refinanced with senior unsecured debentures under the FEI Trust Indenture. FEI further states that its Trust Indenture limits the ability to issue secured debt and it is not prudent to continue to use secured debt as it is restrictive and inefficient.[120]

In the Application, using an assumption of a 5 percent yield for new issuances, FEI presented the impact of changes in ROE and common equity ratio under different scenarios on its issuance capacity under the Trust Indenture, as follows:

[119] Exhibit B-1, p. 27.
[120] Exhibit B-1, pp. 27–28.

Table 4.3: Scenario Analysis of ROE and Equity on Issuance Capacity under the Trust Indenture[121]

	(CAD$ 000s)
Increased Scenario - 9.25% ROE and 40% Equity[1,2,3]	767,800
Status Quo - 8.75% ROE and 38.5% Equity	595,600
Decreased Scenario - 8.25% ROE and 37% Equity[1,2,3]	430,000

1 - Impact On Earnings due to change in ROE = (2014 Mid-Year Rate Base X Status Quo Equity % X Incremental Change in ROE from Status Quo)/(1-2014 Effective Tax Rate)

2 - Impact On Earnings due to Change in Equity = (2014 Mid-Year Rate Base X Incremental Change in Equity from Status Quo % X New ROE%)/(1-2014 Effective Tax Rate) + Incremental Interest Due to Change in Debt = 2014 Mid-Year Rate Base X Incremental Change in Debt% from Status Quo X New Issuance Yield (5%).

3 - Impact of Changes in ROE & Equity to Status Quo Issuance Capacity = ((Impact on Earnings due to Change in ROE + Impact of Earnings due Change in Equity)/2) Incremental Interest Due to Change in Debt)/New Issuance Yield (5%)

FEI also demonstrates that its ability to issue debentures becomes more constrained when the new debt yields are assumed to be higher than 5 percent.[122]

FEI stated that if there is a decline in the allowed ROE and/or common equity ratio, there would be implications on its debt issuance capacity including:

- A decline in allowed ROE and/or capital structure would lead to a decline in credit metrics, which in turn could lead to a credit rating downgrade that would increase the cost of borrowing; and
- The resulting increase in the cost of borrowing would further constrain FEI's debt issuance capacity.[123]

FEI provided the following table to show the required debt and equity financing for the capital projects, subject to timing and approval uncertainties.

Table 4.4: FEI's Total Capital Expenditure and Financing 2016-2018[124]

	2016	2017	2018
Approved Major Capital Projects	130,000	160,000	205,000
Potential Growth Projects[3]	-	525,000	525,000
Expected Total Capital Expenditures[2]	**130,000**	**685,000**	**730,000**
Debt Financing[1]	80,000	420,000	450,000
Equity Financing	50,000	265,000	280,000

1 - Excludes refinancing of $200 million of debt maturing during the period

2 - Excludes financing required of formulaic capital which is partially funded through depreciation cost.

3 - Relates to Tilbury 1B expansion and Woodfibre

FEI provided the following table to show the sensitivity of its debt issuance capacity to a range of possible interest rates assuming a decreased, status quo and increased ROE and common equity component.

121 Exhibit B-1, p. 30.
122 Exhibit B-1, p. 30.
123 Exhibit B-9, BCUC IR 11.1.
124 Exhibit B-9, BCUC IR 11.3.

Table 4.5: Sensitivity of Issuance Capacity to Cost of Debt (Issuance Rate)

(CAD$ 000s)	Decreased ROE & Equity	Status Quo ROE & Equity	Increased ROE & Equity
Issuance Capacity at 5.0%	430,000	595,600	767,800
Issuance Capacity at 6.0%	330,800	473,400	621,400
Issuance Capacity at 7.0%	260,100	386,200	517,000

Mr. Coyne forecasts a risk free rate (long Canada bond) of 3.68 percent based on 2016-2018 forecast data from the Consensus Economics Inc. (Consensus Economics) Survey Data.[125] Mr. Coyne presents the average Canadian utility bond spread vs. 30-year Canada long bond as 1.33 percent and notes that similar to 2013, it has remained somewhat elevated at 1.868 percent.[126] He also presented FEI's spread over 30-year Government of Canada bonds as 1.82 percent for the period from September to November 2015.

Dr. Booth does not agree with FEI's assessment that it might have issues with its interest coverage ratio (ICR) restriction in its bond indenture and as a result, FEI will not have issues accessing capital market. In his view, FEI's ICR analysis has the following deficiencies:

- FEI's ICR is over 2.2 in its recent filing with its securities regulators;
- High quality utilities have no problem accessing capital market; and
- In the current the state of the financial system FEI should have no problems financing itself with his recommended financial parameters.[127]

With respect to debt issuance capacity, Dr. Booth concludes:

> There are some timing differences in the numbers used in the ICR as there are some smoothing options, but the net result is that FEI has considerable financing flexibility and is not currently constrained by the ICR in issuing MTNs. For example, in August 2015 FEI negotiated a syndicated $700 million credit facility of which approximately half is currently unused. On April 8, 2015 FEI issued $150 million of 30 year MTNs at 3.375% using the proceeds to repay short term debt. At the time the 30 year long Canada bond (Cansim V39056) was yielding 2.03% for a 1.35% credit premium. In September 2015 it repaid $75 million of the PMMs with short term notes.[128]

Dr. Booth's evidence includes the Royal Bank of Canada's (RBC) forecast for the 2017 30-year long Canada bond yield of 3.65 percent[129] and notes FEI recently issued bonds at an approximate 1.35 percent over equivalent maturity long Canada bonds.[130] Further, Dr. Booth does not expect the Canada bond yield to exceed 3.8 percent over the next three years.[131]

FEI states that the issuance test under the Trust Indenture differs from the ICR disclosed in FEI's SEDAR filings (SEDAR ratio) in a number of ways. Included among these is the fact the Trust Indenture ratio is prospective whereas the SEDAR ratio is a historic earnings coverage ratio. Further, the SEDAR ratio only includes earnings

[125] Exhibit B-1, Appendix B, p. 41.
[126] Exhibit B-1, Appendix B, pp. 19–21.
[127] Exhibit C7-7-2, p. 2.
[128] Exhibit C7-7-2, p. 85.
[129] Exhibit C7-7-2, p. 23.
[130] Exhibit C7-7-2, p. 1.
[131] Exhibit C7-7-2, p. 2.

and interest from the past year, whereas the issuance test under the Trust Indenture requires the interest on new debentures being issued to be covered as well.[132]

FEI submits:

- Dr. Booth has made the same error in his current evidence as he had made in 2012 in referencing the SEDAR filed ratio as the test used to determine FEI's ability to issue new debt under the Trust Indenture. FEI submits that the SEDAR filing is a requirement for securities compliance purposes and cannot be used as a replacement for the specific terms of FEI's Trust Indenture in determining if it is allowed to issue new debt;[133]
- FEI's issuance capacity would decline materially were the Commission to accept Dr. Booth's recommended ROE of 7.5 percent and a 35 percent common equity ratio;
- There would be considerable risk of a downgrade by Moody's if Dr. Booth's recommended ROE and capital structure are adopted and a downgrade could lead to further constraint on the debt issuance coverage ratio through higher borrowing costs;[134]and
- In an increasing interest rate environment, this capacity would become even further constrained.

<u>FEI reply submission</u>

FEI submits that AMPC/BCOAPO cannot rely on Dr. Booth's evidence on the Trust Indenture and since Dr. Booth did not have a proper understanding of the Trust Indenture, he would not have been able to assess his recommended ROE and common equity ratio against the capital attraction element of the Fair Return Standard. FEI also refers to its rebuttal evidence highlighting how its debt issuance capacity may be significantly constrained in a period of higher debt capital requirements if Dr. Booth's recommended ROE and deemed equity were to be adopted.[135]

Commission determination

In the Panel's view, the key determinants of whether FEI is likely to be constrained in its ability to issue debt under its Trust Indenture for the 2016 to 2018 period include:

1) An estimate of the most probable interest rate for the period;
2) Debt issuance requirements related to expected capital expenditures and debt retirements in the period and the availability of other financing sources that do not impact the Trust Indenture test; and
3) The Commission decision on ROE and common equity ratio.

The Panel focuses on the 2016 to 2018 period since FEI points to its capital expenditure requirements as the key issue impacting its ability to issue debenture especially if new debt yields are assumed to be higher than 5 percent.

In order to evaluate FEI's evidence related to the various scenarios for ROE and common equity ratio and new debt issuance yields, together with its analysis of required debt and equity financings, the Panel first considers

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[132] Exhibit B-16, p. 11.
[133] FEI Final Submission, p. 62.
[134] FEI Final Submission, p. 63.
[135] FEI Reply Submission, p. 45.

the expert evidence in the proceeding related to the expected interest rates for the period 2016 to 2018 compared to the interest rate used by FEI in the various scenarios. Although their approach to determining the risk free rate and their source differs, in that Dr. Booth evidence includes RBC's 2017 forecast and Mr. Coyne used the Consensus Economics forecast for 2016 to 2018, these forecasts of the risk free rate within the 2016 to 2018 period are similar at 3.65 and 3.68, respectively. Their reference points for utility bond are also similar with Mr. Coyne's evidence presenting the average Canadian utility bond spread vs. 30-year Canada long bond as 1.33 percent and recent FEI spreads of 1.82 percent and Dr. Booth referencing FEI's recent issuance at a spread of approximately 1.35 percent over an equivalent maturity long Canada bond. **Considering the expert evidence on the risk free rate and the utility bond spread, the Panel finds the most likely interest rate outcome presented in the sensitivity analysis in Table 4.5 is the analysis using an assumption of 5 percent on new debt issuances.**

With respect to the evidence related to the various scenarios for ROE and common equity ratio and new debt issuance yields, together with its analysis of required debt and equity financings, the Panel notes the following:

1) FEI has included the required debt and equity financing for both approved and potential capital projects, subject to timing and approval uncertainties, and the Panel accepts this as a reasonable estimate of the maximum requirements for the 2016 to 2018 period given the number of uncertainties;
2) $200 million PMMs mature September 2016 and that there are no other significant material maturities of long-term debt in the 2016 to 2018 period. FEI has adjusted the issuance capacity scenarios for the refinancing of the $275 million PPMs;
3) Moody's July 2015 credit opinion forecasts improvements in metrics after completion of the expected capital expenditures in 2016 and 2017; and
4) While there are some limits, FEI has the ability to issue some secured debt under its Trust Indenture if necessary and has some remaining capacity on its $750 million credit facility to cover any short-term needs.

The Panel is of the view that the status quo scenario (8.75 percent ROE and 38.5 percent common equity component), assuming both a 5 percent and 6 percent yield on new debt issuances, demonstrates that FEI has sufficient capacity under its Trust Indenture to meeting its financing needs in the 2016 to 2018 period. FEI does not become constrained until interest rates reach 7 percent which given the expert evidence, the Panel considers unlikely. Further, in the event FEI is faced with interest rates at this level, it has other alternatives related to its ability to issue secured debt, alter the timing of certain capital expenditure or bring an application to the Commission for a change in ROE. Accordingly, **the Panel finds that an increase is ROE or common equity component is not required to support FEI's ability to issue debt under its Trust Indenture.**

The Panel agrees with FEI's submission that its issuance capacity would decline materially were the Commission to accept Dr. Booth's recommended ROE of 7.5 percent and a 35 percent common equity ratio. This is demonstrated by the 8.25 percent ROE and 37 percent equity scenario presented by FEI which represents a near break-even point at an assumed interest rate of 5 percent for new debt issues. In addition, the Panel agrees that such a scenario could increase the risk to a level that could lead to a downgrade by Moody's. If a downgrade were to occur, it could lead to further constraint on the debt issuance coverage ratio through higher borrowing costs. Accordingly, **the Panel finds that a reduction of ROE and common equity component to the levels recommended by Dr. Booth could impact FEI's ability to issue debt under its Trust Indenture.**

4.3.3 FEI's common equity component relative to other Canadian utilities

Mr. Coyne's comparison of the Canadian peer group companies' equity components in relation to his overall risk ranking is included in the table below:

Table 4.6: Canadian Peer Group Comparative Risk Analysis and Authorized Equity Ratio[136]

Operating Company	Risk assessment relative to FEI	Authorized equity component
Proposed FortisBC Energy Inc.	N. A.	40.0%
Current FortisBC Energy Inc.	N. A.	38.5%
ATCO Gas	Less risky	38.0%
Enbridge Gas Distribution Inc.	Less risky	36.0%
Union Gas	Less risky	36.0%
Gaz Métro	More risky	38.5%

With respect to FEI's proposed common equity ratio, Mr. Coyne concludes that FEI's proposed capital structure is "appropriate, albeit conservative." Mr. Coyne states that FEI has higher risk relative to its Canadian peer companies with the exception of Gaz Métro. He also states that Gaz Métro is riskier than FEI and it "enjoys a substantial portion of deemed preferred equity, effectively acting as a further buffer for debt holders." His view with respect to the US proxy group is that FEI's proposal would fall below the entire range of US companies in his proxy group and FEI's proposal is conservative because of FEI's higher relative risk.[137]

In his report, Dr. Booth ranks FEI in the same risk category of gas distributors and identifies FEI as slightly riskier than EGDI and ATCO Gas and is lower risk than either Union Gas or Gaz Métro. Dr. Booth also states the differences in risk between the utilities are tiny.[138]

In his rebuttal evidence, Mr. Coyne states he agrees with Dr. Booth that Gaz Métro is slightly riskier than FEI. Mr. Coyne considers Gaz Métro to be FEI's closest comparator and notes it has the same common equity ratio as FEI of 38.5 percent as well as an allowed 7.5 percent deemed preferred equity at a return of 5.95 percent. In Mr. Coyne's opinion, this is equivalent to roughly 43.5 percent equity at Gaz Métro's current authorized return of 8.90 percent[139] which puts Gaz Métro's allowed equity component above that being requested by FEI in this proceeding. Mr. Coyne considers this appropriate given Gaz Métro's relative risk to FEI.

[136] Exhibit B-1, Appendix B, p. 101.
[137] Exhibit B-1, Appendix B, p. 102.
[138] Exhibit C7-7-2, p. 78.
[139] Exhibit B-16, Prepared Rebuttal Testimony of Mr. Coyne, p. 39, Mr. Coyne's calculation supporting the equivalent equity ratio of 43.5% is calculated as follows: ((5.95% x 7.5%)+(38.5% x 8.90%))/8.9%.

With respect to its main Canadian comparators, FEI submits:

- The reasonableness of its proposed common equity ratio of 40 percent is supported by ratios of other major Canadian natural gas distribution utilities in that a 40 percent common equity ratio places FEI between the higher risk Gaz Métro (equivalent of 43.5 percent at its allowed return on common equity) and lower risk utilities EGDI (36 percent), Union Gas (36 percent) and ATCO Gas (38 percent).[140]
- No other Canadian natural gas distributor has an allowed common equity ratio as low as Dr. Booth's recommendation of 35 percent.
- ATCO Gas is less risky than FEI and has a common equity ratio of 38 percent.[141]

Intervener submissions

AMPC/BCOAPO submit that Mr. Coyne recommends a common equity ratio for FEI that is in excess of the ratio of any of the comparable Canadian utilities.[142] AMPC/BCOAPO support Dr. Booth's recommendation of the same capital structure (i.e. 35 percent) for all of the comparative Canadian utilities, with the exception of Gaz Métro. AMPC/BCOAPO submit it is misleading for FEI to refer to the equity component of Gas Métro as 46 percent including preferred shares because preferred shares are very different from the perspective of the ratepayer and the shareholder and should not be equated. AMPC/BCOAPO further submit "if it is necessary that FEI have more 'equity' to meet credit metric requirements AMPC/BCOAPO supports the Board requiring FEI to issue preferred shares rather providing common shareholders with excessive returns or an overly thick common equity ratio."[143] The issue of preferred shares is addressed in Section 4.3.3.1.

CEC prefers Dr. Booth's view of comparative Canadian companies and submits that FEI's view of its risks relative to the risks of comparable Canadian utilities overstates the appropriateness of a 40 percent common equity component.[144]

FEI reply submission

FEI submits its proposed 40 percent common equity component is well below Gaz Métro's 43.5 percent after accounting for Gaz Métro's deemed preferred shares (not the 46 percent referred to by AMPC/BCOAPO) and is above the major natural gas distribution utilities that the experts agree are less risky than FEI.[145]

Panel discussion

The Panel notes Mr. Coyne's opinion that the Canadian regulatory practice differs from the US practice where it is more common for a US regulator to look at the proxy group of similarly situated companies and then make a determination as to whether or not that company's capital structure is reasonably within the range, given its overall risks, its capital expenditure programs, etc. He also states in Canada, it is more common for a regulator to deem a capital structure based on risk analysis and credit metrics.[146]

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[140] FEI Final Submission, p. 4.
[141] FEI Final Submission, p. 60.
[142] AMPC/BCOAPO Final Submission, p. 10.
[143] AMPC/BCOAPO Final Submission, pp. 63–64.
[144] CEC Final Submission, p. 48.
[145] FEI Reply Submission, p. 43.
[146] Oral Hearing Transcript Volume 3, p. 372.

In the Panel's view, while there are differences in the parties' views of an appropriate common equity ratio for FEI, there is general agreement of the relative risk ranking of FEI's comparator Canadian natural gas distribution utilities. All parties agree that EGDI, Union Gas and ATCO are less risky than FEI and Gaz Métro more risky. The Panel accepts this relative risk ranking as a check on our determinations.

4.3.3.1 Introducing preferred shares to FEI's capital structure

The issue of introducing preferred shares to FEI's capital structure was raised by Dr. Booth. He states that "FEI should not be allowed more than the Fair Return Standard due to bond market problems. If any such problems exist, and I don't think they currently do, they can be addressed with a short term solution, such as issuing term preferred shares."[147]

Intervener submissions

AMPC/BCOAPO submit that as an alternative to increasing the common equity component, if FEI requires more equity to meet its credit metrics, the Commission can require FEI to issue preferred shares.[148] They further submit that any concerns with Dr. Booth's recommendation of 35 percent common equity ratio can be addressed by deeming some preferred shares in the capital structure.[149]

AMPC/BCOAPO refer to FEI's final submission in the 2012 GCOC proceeding in which FEI submits "the introduction of preferred equity into the capital structure has the same effect on the cost of equity as adding debt." AMPC/BCOAPO submit the introduction of preferred shares into the capital structure will improve access to the debt market because preferred shares dividends are paid out of after-tax income, must be declared by the Board of Directors and do not constitute interest in the interest coverage test for new debt issuances.[150]

FEI reply submission

FEI submits the intervener evidence presented in this proceeding is not sufficient for the Commission to be able to 'properly assess the ramifications of mandating the introduction of preferred shares into FEI's capital structure. FEI states that the interveners put forward the same proposal in the 2009 proceeding, and this proposal was not accepted as the Commission determined that FEI's capital structure should remain in the form of debt and common equity.[151]

Commission determination

The Panel agrees with FEI and the Panel finds the issue of introduction of preferred shared into FEI's capital structure has not been explored sufficiently in this proceeding for the Commission to make a determination on this issue.

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[147] Exhibit C7-7-2, p. 86.
[148] AMPC/BCOAPO Final Submission, pp. 63–64.
[149] APMC/BCOAPO Final Submission, pp. 66–67.
[150] APMC/BCOAPO Final Submission, p. 67.
[151] FEI Reply Submission, p. 45.

4.4 Appropriate capital structure

Commission determination

The Panel has determined a common equity component of 38.5 percent is appropriate for FEI, effective January 1, 2016. This represents no change from the 2013 GCOC Decision where the Commission determined the same equity component.

The Panel notes that the 2013 GCOC Decision put considerable emphasis and weight on changes in long-term risk associated with provincial government climate and energy policies as well as the competitive position of natural gas relative to electricity in reaching its common equity ratio determination. In this proceeding, the provincial government climate and energy policies were covered as part of what was termed political risk and the competitive position of natural gas as compared to electricity was addressed under energy price risk.

The parties generally agree there is little change with respect to the level of risk in a number of identified risk areas as compared to the 2013 GCOC Decision. The parties also appear to be in general agreement that there is little change in operating risk, market shift risk and the risk associated with economic conditions since the last decision. In addition, none of the parties take issue with the position taken by FEI that the amalgamation of FEW and FEVI with FEI has not resulted in any material risk change for the amalgamated Company and the combined entity's business profile remains much the same.

However, there were a number of important areas where the parties were in disagreement which were more closely examined by the Panel. Probably most contentious among these was with political risk where the Panel determined there was a slight increase in risk primarily due to developments at municipal and provincial government levels. Under the same political risk category, the Panel was not persuaded the evidence on recent jurisprudence concerning First Nations would have a material effect on FEI's ability to earn a return of on and of its capital. Offsetting the increase in political risk to some degree was the Panel's determination that energy price risk has decreased somewhat. As noted in Section 4.2, the Panel finds there was little change in regulatory risk and only a slight increase in energy supply risk. Taking these factors together and weighing them accordingly, the Panel considers there to be insufficient justification for awarding either a higher or lower equity ratio at this time.

The Panel also examined potential for FEI's credit ratings to affect its access to capital and found there is no compelling evidence to support the need to increase the common equity component to maintain its current credit rating. A similar conclusion was reached with regard to FEI's trust indenture issuance test where it was found that given the current equity ratio and ROE, there is little evidence FEI's ability to issue debt will be constrained.

As a check, the Panel notes FEI's deemed capital structure of 38.5 percent equity falls within the range among its Canadian comparators. This, while not determinative, does provide a level of comfort with respect to the Panel's decision to leave FEI's common equity component unchanged.

5.0 RETURN ON EQUITY

5.1 Overview of issues

In setting a fair ROE, the Panel must make a determination of a return representing the rate of return that equity investors could expect to earn elsewhere in the market without bearing more risk. Since investors' expectations are not directly observable in the market, it is necessary to make an estimate of the opportunity cost of an alternative investment of equivalent risk. The Panel notes the following guidance provided by the Brattle Group Report (Exhibit A2-3):

- There is no single, widely accepted, best financial model used to estimate the cost of capital;
- Models are imperfect tools but can be useful simplifications of reality;
- Cost of capital estimation continues to be as much art as it is science; and
- To make an appropriate estimate one should consider the "totality of information from alternative methodologies."[152]

In this proceeding, Dr. Booth and Mr. Coyne have presented estimates of investors' expectations based on data that they interpret through the use of variations on the capital asset pricing model (CAPM) and the discounted cash flow model (DCF model). The use of these two models is consistent with the 2013 GCOC Decision, where the Commission found that:

> The two most compelling frameworks for assessing the cost of equity are the DCF model and the CAPM. These models have well understood theoretical bases and explicitly recognize the opportunity cost of capital. Accordingly, these two models are given equal weight in determining the allowed ROE.[153]

The experts' approach to the use of these models to estimate an investor's opportunity cost differs significantly in a number of areas and result in recommendations of a fair ROE ranging from Dr. Booth's 7.5 percent to Mr. Coyne's 9.5 percent.

With a focus on the differences in approach by the experts, the key questions the Panel addresses in making its determination of an appropriate ROE are as follows:

i) Should the decision be informed by use of multiple financial models and other indicators of investor expectations?

ii) In the development of the models, is the selection of the proxy group and the weight placed on US data appropriate?

iii) With respect to both the CAPM and DCF estimates, are the model inputs used by the experts reasonable and how much weight should be given to each of these models and the resulting estimates?

iv) In applying the Panel's judgment to the totality of information, what is a fair return on equity for FEI?

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[152] Exhibit A2-3, The Brattle Group, Survey of Cost of Capital Practices in Canada, Prepared for the British Columbia Utilities Commission (Brattle Group Report), May 31, 2012, pp. 3–4.
[153] 2013 GCOC Decision, p. 56.

5.2 Key differences in views related to ROE

5.2.1 Use of multiple financial models

Mr. Coyne states that use of the CAPM and DCF models, each with its own set of inherent limitations, provide different perspectives as well as depth to the analysis that helps inform the estimate of ROE. He cautions that neither model should be relied upon individually without corroboration from other approaches. In his opinion, it is necessary to use best judgment to assess the reasonableness of the result and to determine the appropriate weighting to apply to the results under current market conditions.[154]

In arriving at his ROE recommendation, Mr. Coyne considered the results of several tests including his constant growth and multi-stage DCF models, his risk premium analysis and the "alternative" CAPM analysis.[155] Mr. Coyne's overall recommendation is supported by placing equal weight on his multi-stage DCF and CAPM models, the same weighting the Commission applied in its 2013 GCOC Decision.[156] Mr. Coyne states that his approach differs from Dr. Booth who places "predominant weight" on the CAPM model.[157]

Dr. Booth disagrees that he primarily relies on CAPM estimates.[158] In arriving at his ROE recommendation, Dr. Booth's considers and applies his judgment to a variety of different indicators of the fair ROE including:

- capital market conditions;[159]
- his simple CAPM;[160]
- equity risk premium estimate or conditional CAPM (CCAPM);[161] and
- DCF estimates to support his adjustments to the CAPM estimates.[162]

He places weight on survey results from the Fernandez survey,[163] and considers other independent estimates, including TD Economics,[164] Aon Hewitt and Mercer.[165]

Final submissions

FEI underlines the importance of employing multiple tests and cites Mr. Coyne's evidence that the CAPM and DCF bring a different perspective since they are based on different premises. FEI submits only by using multiple tests can the Commission be assured of a reasonable estimate of ROE.[166]

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154 Exhibit B-1, Appendix B, pp. 34–37.
155 Exhibit B-1, Appendix B, pp. 104–106.
156 Oral Hearing Transcript Volume 1, p. 20; Exhibit B-1, Appendix B, pp. 104–106.
157 Oral Hearing Transcript Volume 1, p. 22.
158 Oral Hearing Transcript Volume 3, p. 503.
159 Exhibit C7-7-2, p. 8.
160 Exhibit C7-7-2, p. 41.
161 Exhibit C7-7-2, p. 50.
162 Exhibit C7-7-2, p. 56.
163 Exhibit C7-7-2, p. 40.
164 Exhibit C7-7-2, pp. 56–57.
165 Oral Hearing Transcript Volume 3, p. 659.
166 FEI Final Submission, p. 65.

AMPC/BCOAPO support Dr. Booth's recommendation for using the CAPM and DCF as a "check on one another and applying judgement as necessitated by external conditions."[167]

CEC submits that the evidence resulting from the application of all models presented in the proceeding should be considered but the Commission should apply its own judgment to determine the appropriate ROE in the current circumstances.[168]

Panel discussion

The Panel notes that while there are some differing perspectives among the experts and parties, their views are generally consistent with the Brattle Group Report's finding that decisions should be informed by use of multiple financial models and other indicators of investor expectations where appropriate. The Panel agrees it should consider the "totality of information resulting from applying multiple tests." The Panel also agrees it should consider all of the information from the application of the models presented, as well as other indicators of the fair ROE and should apply its own judgment to determine the appropriate ROE.

5.2.2 Selection of US and Canada proxy groups and US data comparability

As noted in Section 2.0, the "comparable investment requirement" of the Fair Return Standard requires the return available from the application of the utility's invested capital to be comparable to the return of other enterprises of like risk. To assess whether the proposed return meets this requirement, Mr. Coyne and Dr. Booth, on behalf of FEI and the Utility Customers respectively, selected a group of proxy companies in other Canadian and US jurisdictions as comparators for FEI.

The primary use of the proxy companies was in the determination of estimation of beta in the CAPM analysis (see Section 5.2.3.4) and estimating ROE's in the constant growth and multi-stage DCF models (see Section 5.2.4.1).

All parties acknowledge that there are no publically-traded, pure play gas distribution companies in Canada. Hence both Dr. Booth and Mr. Coyne assessed a sample of US companies that are primarily engaged in natural gas distribution in order to assess the market expectations specific to a natural gas distribution utility.[169]

Both consultants also chose a group of Canadian proxy companies. However, because of the lack of pure play gas distribution companies in Canada, the proxy companies are mainly holding companies with a variety of business interests that differ from FEI's business profile.

The uses and limitations of the proxy companies are set out in the followings sections.

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[167] AMPC/BCOAPO Final Submission, p. 38.
[168] CEC Final Submission, p. 13.
[169] Oral Hearing Transcript Volume 3, pp. 581–595; FEI Final Submission, p. 77.

5.2.2.1 Selection and use of US proxy companies

FEI asserts that US utilities can be appropriate comparables and that US data requires no adjustment."[170] Mr. Coyne stated US companies are appropriate comparables for use in the various models to estimate a fair ROE for FEI because:

- US and Canadian utilities operate in similar macro-economic environments;
- US and Canadian utilities are governed by comparable regulatory models;
- US and Canadian capital markets are closely linked and move in parallel;
- There is a great deal of cross-border utility investment; and
- Canadian and US utilities compete for capital in a North American market.[171]

Dr. Booth chose his US proxy companies by selecting US companies that had been used in previous proceedings by other expert witnesses for this purpose. Dr. Booth eliminated companies that were no longer appropriate because of merger activity and added three companies based on his review of their descriptions in Google's gas index.[172] Mr. Coyne used a sample of seven US companies while Dr. Booth had eight companies in his proxy group. Six of the companies were common to both samples.

Mr. Coyne asserts that Canadian and US utilities are governed by comparable regulatory models. As evidence of this, he cites a 2013 Moody's report concluding that utility regulation in Canada and the United States is comparable. He also quotes an OEB decision finding that US utility comparators could be used, requiring "only an analytic framework in which to apply judgment and a system of weighting."[173] Mr. Coyne acknowledged that in a 2013 decision, the Newfoundland and Labrador Public Utilities Board made a downward adjustment of 0.5 to 1.0 percent to US DCF results but claimed that this did not reflect "the broader Canadian landscape on this matter."[174]

In his evidence, Mr. Coyne provides detailed information on the proxy companies he used in his ROE models. Table 5.1 summarizes some of the evidence with respect to regulatory practices or actions impacting the US proxy companies that differ from the regulatory practices facing FEI. While the list is not intended to be exhaustive, it demonstrates some of the elements the Panel must consider when evaluating such comparisons.

[170] FEI Final Submission, p. 77.
[171] Exhibit B-1, Appendix B, Evidence of Mr. Coyne, p. 87.
[172] Oral Hearing Transcript Volume 3, pp. 586–587.
[173] Exhibit B-8, AMPC IR 4.2.
[174] Exhibit B-8, AMPC IR 4.5.

Table 5.1: Differences in Regulatory Practices of Mr. Coyne's US Proxy Companies Compared to FEI

US Proxy Company	**Differences in Regulatory Practice Compared to FEI**
Atmos Energy Corporation*	(Comments are related to Texas where 70% of Atmos' regulatory assets are located) • Some capital additions may be brought into rates without prior regulatory approval[175] • Elected regulators who receive political donations from Atmos[176] • Test year determined on a historical basis[177]
South Jersey Resources Corp.*	• Partially forecast test year[178]
Northwest Natural Gas*	Oregon • Partially to fully forecast test year • No interim rates Washington • Historical test period • Interim rates allowed under emergency circumstances[179]
Piedmont Natural Gas*	• Historical test period in North and South Carolina • Formula rate plan (annual rate mechanism) in Tennessee and North Carolina[180]
New Jersey Industries, Inc.	• Partially forecast test year • Interim rates allowed on an emergency basis • Company retains 100% of the first $7.8 million of margins associated with off-system sales, interruptible sales, and interruptible transportation activities. Margins beyond this are allocated 85% to ratepayers and 15% to the company[181]
Southwest Gas Corporation*	• Historical test year • Interim rates not allowed in Nevada, allowed on an emergency basis in California[182]

[175] Oral Hearing Transcript Volume 2, pp. 408–410.
[176] Oral Hearing Transcript Volume 2, pp. 413–414.
[177] Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-59.
[178] Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-64.
[179] Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-68.
[180] Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-72.
[181] Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-76.
[182] Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-81.

WGL Holdings Inc.*	• Historical test year with some items forecast in Washington, DC • Historical test year in Virginia and Maryland • Interim rates are rarely requested in Maryland and generally not requested in Washington, DC[183]

*Also used as a proxy company by Dr. Booth

Mr. Coyne was specifically asked about one of the proxy companies used in his ROE analysis, Atmos Energy Corporation (Atmos), and its treatment by the Texas regulator with respect to allowing capital expenditures that are brought into rates without the regulators' approval. He was also asked to comment on how this treatment compares to the handling of FEI capital expenditures. Mr. Coyne replied that "... just and reasonable rate standards are going to apply at the end of the day and they'll be held to that standard."

When cross-examined about whether there was a difference in political or regulatory risk in jurisdictions where the regulators are elected and utilities may contribute significant funds to regulators running for election, such as in Texas, or where they are appointed, as in BC, Mr. Coyne stated that in his view, the experience and background of the regulators was more relevant than whether they were elected or appointed.[184] He also noted that Atmos operates in eight states.[185]

FEI argues that Mr. Coyne's analysis of regulatory risk facing his US proxy companies demonstrates:

> …the U.S. regulatory environment is generally characterized by widespread use of regulatory mechanisms that are viewed as credit supportive, including accounts that provide for recovery of gas costs for gas utilities and fuel and purchase costs for electric utilities, revenue decoupling, weather normalization accounts, trackers for new infrastructure investment (gas utilities), mechanisms for the recovery of bad debt expenses, and the ability to include CWIP in rate base.[186]

FEI further argues that the majority of the companies in Mr. Coyne's proxy sample operate in more than one regulatory jurisdiction, which diversifies their regulatory risk.[187]

In Dr. Booth's view, there are a number of issues to be considered when using US proxy companies as comparators. These include:

- Growth rate instability related earnings over the past five years. Dr. Booth notes growth rates have varied from negative 17.09 percent for one of the proxy companies to positive 29.23 percent for another.[188]
- Optimism bias of analysts in estimating earnings growth.[189] Dr. Booth states that since analyst earnings forecasts are used to predict growth rates, the use of the DCF model is suspect even for "low risk" utilities.[190]

[183] Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, pp. A-86–A-87.
[184] Oral Hearing Transcript Volume 2, p. 413.
[185] Oral Hearing Transcript Volume 2, p. 415.
[186] FEI Final Submission, p. 78.
[187] FEI Final Submission, p. 78.
[188] Exhibit C7-7-2, Appendix D, p. 14.

- Lower levels of capitalization of US proxy companies. In Dr. Booth's view, this results in some parties arguing that this indicates a higher level of risk for these companies.[191]

Dr. Booth testified he believes the risk of US utilities is clearly higher than Canadian utilities and "the underlying basic estimates indicates that US utilities are riskier than Canadian utilities."[192] CEC agrees with this assessment and argues that the evidence from US companies should be given less weight or should be adjusted based on the inherent differences between Canadian and US utilities.[193]

5.2.2.2 Canadian proxy companies

Because other regulated gas utilities in Canada are not stand-alone companies, in calculating CAPM and DCF rates of return, Mr. Coyne uses the following Canadian proxy group most of which are holding companies:

- Canadian Utilities Ltd. (an Alberta based company that is in the gas distribution business in Alberta and Australia and also in the electric distribution and transmission business as well as in modular construction e.g. work camps etc.);
- Emera Inc. (a Nova Scotia electric company engaged in a takeover bid of TECO in the US. Also provides electric service in Maine and the Caribbean);
- Enbridge Inc. (although it has a large gas distribution company in Ontario, also has a significant oil and gas transmission pipeline business);
- Fortis Inc. (parent of FEI, a holding company with 93 percent of its assets in regulated businesses – gas and electric in Canada, the US and the Caribbean); and
- Valener Inc. (has a 29 percent interest in Gaz Métro as well as significant wind farm interests – partnered with Gaz Métro).[194]

Mr. Coyne states that "only three of the five companies in the Canadian proxy group derived more than 70 percent of their operating income from regulated activities; and only one company, Valener would also satisfy the regulated gas utility screen. This is a clear indication that a Canadian utility group cannot be created to reliably resemble the risks and business profile of FEI."[195] Mr. Coyne further states he includes his Canadian proxy group "to provide a benchmark for the risks and resulting cost of capital for Canadian utilities in general."[196]

Dr. Booth, in assessing other Canadian utilities, looked at the same companies used by Mr. Coyne; Enbridge Inc., Canadian Utilities, Emera, Fortis Inc., Valener, and in addition, Veresen Inc. (a company with pipeline, midstream and electric power businesses) and TransCanada Corporation (a company with natural gas and oil transmission pipelines and electric power generation).[197] Mr. Coyne excluded the use of TransCanada Corporation on the

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[189] Exhibit C7-7-2, Appendix D, pp. 14–16.
[190] Exhibit C7-7-2, Appendix D, p. 14.
[191] Exhibit C7-7-2, Appendix C, p. 9.
[192] Oral Hearing Transcript Volume 3, pp. 662–663.
[193] CEC Final Submission, pp. 15–16.
[194] Exhibit B-1, Appendix B, Evidence of Mr. Coyne, Appendix A, pp. A-16 to A-51.
[195] Exhibit B-1, Appendix B, p. 33.
[196] Exhibit B-1, Appendix B, p. 29.
[197] Exhibit C7-7-2, Evidence of Dr. Booth, Appendix C, p. 8.

basis that it "is subject to a completely different set of competitive risks than the average natural gas distribution utility."[198]

Commission determination

The Panel finds the use of US proxy companies as comparators to assist in the determination of what is the appropriate rate of return for FEI in terms of meeting the Fair Return Standard is relevant.

However, the Panel notes Mr. Coyne's statement that:

> Notwithstanding the care taken to ensure comparability, market expectations with respect to future risks and growth opportunities vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. At issue, then, is how to select an ROE estimate in the context of that range. That determination must be based on an assessment of the company specific risks relative to the proxy group and the informed judgment and experience of the analyst.[199]

The Panel finds that the screening criteria used by Mr. Coyne to choose his US proxy companies are reasonable for consideration in assessing growth rate in the DCF model and capital structure. The companies chosen are found by the Panel to have business characteristics somewhat but not directly comparable to FEI. The Panel also found the detailed information provided by Mr. Coyne on each proxy company to be useful in its determinations. **The Panel also finds that the eight US proxy companies chosen by Dr. Booth, although not chosen with the same rigour as employed by Mr. Coyne, includes six of the companies used by Mr. Coyne, and is also a reasonable sample.**

However, the Panel does not agree with Mr. Coyne that the regulatory environment affecting FEI is directly comparable to the regulatory environments faced by the US proxy companies. The Panel is not persuaded that Moody's statement that utility regulation in Canada and the United States is comparable means that there are no differences in the respective regulatory environments that affect levels of risk and the comparability of the allowed ROE for US and Canadian utilities. We note that in addition to some of the differences set out in Table 5.1 above, there is also a question as to whether there are significant differences in the use of deferral accounts and differences in approved forecasting methodologies between FEI and the US proxy companies. Mr. Coyne provided evidence with information on what is described as "significant" deferral accounts used by his proxy companies.[200] **The Panel finds that the evidence is not persuasive in demonstrating that the US proxy companies have access to the same suite of deferral accounts that exists in FEI's rate structure.**

The Panel considers the use of US proxies to be a framework against which a fair return ROE may be assessed, but it is not a clear mathematical determinant that can be simply plugged into an ROE calculation. The regulatory environments of US proxy companies operate are varied and differ in a number of respects from the regulatory environment faced by FEI in British Columbia. The US proxy data, while useful, is an imperfect reflection of the circumstances facing FEI and requires considerable judgment as to the weight to be placed on this data. The Panel is not persuaded the evidence in this proceeding is sufficient to warrant a change in the

[198] Exhibit B-1, Appendix B, p. 31.
[199] Exhibit B-1, Appendix B, p. 29.
[200] Exhibit B-1, Appendix B, Appendix A, pp. A-57 to A-87.

Commission's 2013 GCOC Decision conclusion that differences exist in the regulatory environments in the US relative to British Columbia.

The lack of stand-alone publically traded natural gas distribution companies in Canada results in the reliance on data from holding companies whose interests include significant assets outside of the natural gas distribution business. The difference in corporate make-up of these proxy companies compared to FEI requires applying considerable judgment to any calculations flowing from this data. **The Panel finds the differences in the business circumstances of the Canadian proxy companies to FEI are significant.** In the Panel's view, this is evident from the proportion of the proxy companies activities in non-regulated activities or in regulated activities not related to natural gas distribution.

In addition, it is the Panel's view that the evidence with respect to ROE and the equity component of utilities in other jurisdictions and the calculations derived from proxy companies can help inform our decision, but are insufficient, in and of themselves, to define it. As is reflected in the sections in this decision dealing with FEI's risk and the assessment of the models used to calculate a fair ROE, the Panel has needed to weigh the implications of the deficiencies of the Canadian proxy companies in terms of differences in business functions compared to FEI and the deficiencies of the US proxy companies in terms of their different regulatory environments.

The Panel is not persuaded Dr. Booth's observation that lower levels of capitalization of US proxy companies relative to FEI may be indicative of higher risk faced by these companies is correct, and the Panel gives little weight to this evidence. The instability in earnings growth for the US proxy companies is viewed by the Panel as indicative of the abnormal economic circumstances that have existed over the past few years and supports placing less reliance on the models and thus more reliance on judgment.

The Panel notes that proxy companies are used in both the CAPM model (to estimate betas) and in the DCF calculation process. In both cases, as set out elsewhere in the decision, estimates are prepared based on the Canadian sample and on the US sample and from this, a figure applicable to FEI is derived. A number of uncertainties are identified in the modelling processes and inputs. The limitations set out in this section, namely that the Canadian proxy group is flawed due to its lack of comparability in business functions to FEI and the use of the US proxy group is hampered by the differences in the regulatory treatment of the US companies. Collectively, these add to the list of uncertainties that the Panel must take into account in determining the ROE and equity ratio for FEI that meets the Fair Return Standard.

5.2.3 CAPM/risk premium model

5.2.3.1 Overview of the CAPM estimates and model

Mr. Coyne describes the CAPM as a forward looking estimate of a security's required return based on the relationship between its required return and its systematic or non-diversifiable risk.[201] Mr. Coyne states, to calculate the required ROE for a given security it is necessary to estimate the:

i) Risk free rate of return;

[201] Exhibit B-1, Appendix B, pp. 39–40.

ii) Return for the market as a whole or the market risk premium (MRP); and

iii) Beta of an individual security or the measure of covariance between the return on a specific security and the market.[202]

Similarly, Dr. Booth describes the risk premium model as the investor's required or fair rate of return represented by the risk free rate plus a risk premium. He states that the CAPM is a special form of risk premium model that relates the individual risk of a security to the overall market risk and specifies that the risk premium consists of the MRP multiplied by the security's relative risk or beta coefficient (beta).[203]

Issues with the CAPM model

With respect to use of the CAPM, the Brattle Group Report states the CAPM:

> …has a transparent and well-explored economic theory underlying it. Its results can be replicated easily, since the data required are widely available from many public sources. Implementing the CAPM, however, requires a number of subjective decisions – decisions which can be hotly contested and can lead to significantly different results.[204]

Mr. Coyne outlines a number of issues with the CAPM including:

i) The approach is sensitive: the method of calculating the risk premium, the selection of a security for the risk free rate, the use of forward-looking or historical data and the determination of whether adjustments to Beta are appropriate;

ii) The model assumes that: (1) all investors will behave in an efficient manner and manage their portfolios to diversify risk and will make investment decisions considering the impact of a security on the portfolio; and (2) the market is well functioning; and

iii) The problems of the CAPM are exacerbated in the current market environment where risk free rates remain near all-time lows[205] and consistent with the views of Dr. Booth, result in the need to modify the traditional CAPM assumptions to achieve a reasonable ROE recommendation.[206]

Dr. Booth states that the CAPM is the most common way of estimating the fair rate of return and it is so widely used because it is "intuitively correct" in that it captures the time and risk value of money.[207] Dr. Booth explains that under normal or average markets, the traditional CAPM reflects the correct opportunity cost for an equity investor as being the bond market plus a risk premium. This view of opportunity cost assumes that conditions in the bond markets affecting the long Canada bond yield are also driving conditions in the equity market. However, in Dr. Booth's view, at the current point in time, conditions in the Canadian bond market are largely being driven by external factors and do not reflect normal or average market conditions.[208] Accordingly, Dr. Booth considers it necessary to make adjustments to the CAPM to reflect the current capital market conditions and to adjust for abnormally low Canada bond yields resulting from global bond buying programs.[209]

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[202] Exhibit B-1, Appendix B, p. 40.
[203] Exhibit C7-7-2, p. 36.
[204] Exhibit A2-3, p. 4.
[205] Exhibit B-1, Appendix B, pp. 35–36.
[206] Oral Hearing Transcript Volume 1, p. 21.
[207] Exhibit C7-7-2, p. 36.
[208] Exhibit C7-7-2, pp. 41–42.
[209] Exhibit C7-7-2, p. 42.

Comparison of CAPM estimates

Table 5.2 compares the expert witnesses' use of the CAPM variants and their estimates.

Table 5.2: Comparison of CAPM Estimates

Expert	Risk-free rate (%)	Market risk premium (%)	Beta	CAPM results (%)	Adjustment (%)	Flotation allowance (%)	CAPM ROE estimate (%)
Mr. Coyne – Canadian proxy group[210]	3.68[211]	7.6[212]	0.65[213]	8.58	--	0.50	9.08
Mr. Coyne – US proxy group	3.68[214]	7.6[215]	0.78[216]	9.58	--	0.50	10.08
Mr. Coyne - average	--	--	--	--	--	--	9.58[217]
Dr. Booth	2.75[218]	5.0-6.0[219]	0.45-0.55[220]	Simple 5.50-6.55[221]	CCAPM (1) +0.45[222] Risk Premium Estimate[223] (2)Operation Twist +1.30[224]	included	7.25 – 8.30[225]

[210] Exhibit B-1, Appendix B, Exhibit JMC-5.
[211] Exhibit B-1, Appendix B, Table 5, p. 41. 3.68 = [(2.1+3.2+3.6)/3]+0.71.
[212] Exhibit B-1, Appendix B, Table 7, p. 49. The Canadian MRP is a range of 5.6 to 9.8 and the US MRP is a range of 7.0 to 8.1 based on historical and forward-looking estimates and 7.6 is the average of the Canadian and US estimates.
[213] Exhibit B-1, Appendix B, Table 6, p. 44.
[214] Exhibit B-1, Appendix B, Evidence of Mr. Coyne, pp. 40–41. 3.68 = [(2.1+3.2+3.6)/3]+0.71; although Mr. Coyne presented 4.29 percent as the US risk-free rate, his US proxy group CAPM calculations in Exhibit JMC-5 Schedules 1 and 2 actually used the 3.68 percent Canadian risk-free rate to arrive at an estimate of 10.08 percent.
[215] Exhibit B-1, Appendix B, Table 7, p. 49. The Canadian MRP is a range of 5.6 to 9.8 and the US MRP is a range of 7.0 to 8.1 based on historical and forward looking estimates and 7.6 is the average of the Canadian and US estimates.
[216] Exhibit B-1, Appendix B, Table 6, p. 44.
[217] Exhibit B-1, Appendix B, Table 21, p. 104.
[218] Exhibit C7-7-2, p. 23, the average of the March and December Consensus Economics forecasts which is a proxy for the average for the year as a whole and consistent with the application to an average forward test year rate base, is 2.75%.

With a focus on the differences in approach by the experts, the key areas the Panel needs to explore in assessing the results of the experts' CAPM estimates are as follows:

i) The adjustments needed to the risk free rate to compensate for the abnormal conditions in the bond markets resulting from the impact of global bond buying programs.

ii) The use of income or total returns in the derivation of the historical MRP.

iii) The methodology to calculate and necessity of using a forward looking MRP to reflect the current expectation of investors.

iv) Testing reasonableness of MRP estimates.

v) The appropriate adjustment to beta.

5.2.3.2 Estimate of risk free rate and adjustment for abnormal conditions

Both Mr. Coyne and Dr. Booth rely on Consensus Economics forecasts of the 30-year Government of Canada bond yield as the risk free rate. However, the experts differ in their approach to an adjustment to the risk free rate to compensate for the abnormal conditions in the bond markets resulting from the impact of global bond buying programs.

Mr. Coyne prepares his estimates of the risk free rate plus an adjustment for abnormal conditions using the 10-year government bond forecast plus the historical spread between 10-year and 30-year government bonds.[226] My Coyne's calculations as follows:

Table 5.3: Mr. Coyne's Calculation of Risk Free Rate Adjusted for Abnormal Conditions[227]

30-Year Risk Free Yield	CDN$	U.S. $
April 2015 Consensus Forecast Average 2016-2018 Forecasts 10-Year bond yield	2.97%	3.60%
Average Daily Spread between 10-year and 30-year government bonds (August 2015)	0.71%	0.69%
Average	3.68%	4.29%

Mr. Coyne selected the 2016 to 2018 period to match the period he expects FEI's rates are most likely to be in effect[228] and explained his use of a three-year forecast in the current abnormal market conditions:

> What I'm saying is that we know conditions are abnormal now. Dr. Booth goes through an exercise he calls 'Operation Twist', to try to account for abnormal bond yields in the government bond yield market. And the approach that I take is to look to a consensus forecast, and to see

[219] Exhibit C7-7-2, p. 39.
[220] Exhibit C7-7-2, p. 41.
[221] Exhibit C7-7-2, p. 41, 5.50= (5.0*.45) + 2.75=2.25+2.75=5.0 + 0.5 flotation = 5.50; and 6.55 = (6*.55) + 2.75 + 0.5 flotation = 6.55.
[222] Exhibit C7-7-2, p. 44.
[223] Exhibit C7-7-2, p. 50, the Risk Premium Estimate is the CCAPM adjusted for an estimate of Operation Twist and is a range of 7.25% to 8.30%.
[224] Exhibit C7-7-2, p. 50.
[225] Exhibit C7-7-2, p. 50.
[226] Exhibit B-1, Appendix B, pp. 40–41.
[227] Exhibit B-1, Appendix B, p. 41.
[228] Exhibit B-1, Appendix A, p. 40.

> what looks like a return to something that's in equilibrium. Just as this commission did in 2012, it made a determination that there should be a floor of the risk-free rate, on a judgment that needed to be something that at least looked like an equilibrium risk-free rate, in order for it to be sensible for a cost of equity determination.
>
> So that's the very same logic here. The difference is that I am not trying to estimate it myself. I am looking at this consensus forecast and I am looking at the shape of it. Because it flattens out once you get to 2018. So it tells me that in that range it gets you to something that looks like equilibrium or more normalized level of risk free bond yield. So, that's the logic. I'm not trying to pinpoint one year, or three years for that matter.[229]

Dr. Booth recommends a 2.75 percent risk free rate based on an average of the 2016 three-month and one-year Consensus Economics forecasts plus the current spread between the 30-year and 10-year bond of 0.75 percent. He concludes that the average of the three month and one year rate is a "proxy for the average for the year as whole and consistent with the application to an average forward test year rate base."[230] In addition, Dr. Booth uses an "Operation Twist adjustment" to adjust for the abnormally low Canada bond yields resulting from rampant bond buying programs by central banks.[231]

In the 2012 GCOC proceeding, Dr. Booth placed the impact of Operation Twist on the Canadian bond market at approximately 80 bps from August 2011 through to May 2013.[232] In the 2013 GCOC Decision, the Commission accepted Dr. Booth's adjustment.[233]

Dr. Booth quantifies the Operation Twist impact by determining the extent to which the differential between the preferred share yield and the corporate A yield has widened under recent market conditions.[234] According to Dr. Booth's evidence, the preferred share yield spread increased from 0.80 percent in 2012 to the current 2015 average of 1.3 percent.[235] Dr. Booth testified that he:

> …looked at the volatility those preferreds and I used the average to try and adjust for their volatility, and I use 1.3. Right now I would lower that to about 60 to 70 basis points, because I've now looked at the composition of that index, and it reflects the behaviour of rate reset preferred shares. I would not continue to make a 1.3 percent spread adjustment based upon those preferreds, because those preferreds are behaving -- significantly behaving as a result of rate reset preferreds.[236]

Dr. Booth also testified he now has less faith in the magnitude of the Operation Twist adjustment but what continues to drive his recommended ROE, consistent with the last four years, is he would not change allowed ROEs until the long Canada rate returns to something approaching normality, which in his view is 3.8 percent.[237]

[229] Oral Hearing Transcript Volume 1, pp. 186–187.
[230] Exhibit C7-7-2, p. 23.
[231] Exhibit C7-7-2, p. 48.
[232] Exhibit C7-7-2, p. 48.
[233] 2013 GCOC Decision, p. 60.
[234] Exhibit C7-7-2, p. 49; Exhibit C7-9, BCUC IR 12.1.
[235] Exhibit C7-7-2, pp. 48–49.
[236] Oral Hearing Transcript Volume 3, p. 538.
[237] Oral Hearing Transcript Volume 3, p. 542.

FEI submits that it is appropriate for Mr. Coyne to use a three-year forecast to estimate a forward looking bond yield that includes anticipated changes over the next few years to reflect the long-term perspective, particularly given current market conditions. FEI also submits that Mr. Coyne's forecast risk free rate plus an adjustment for abnormal conditions of 3.68 percent is very near to the RBC forecast of 3.65 percent for Q4 2017 which Dr. Booth has included on page 23 of his testimony.[238]

FEI submits a reasonable Operation Twist adjustment is an essential precondition to the reliability of the risk premium model output because Operation Twist is the only feature differentiating Dr. Booth's risk premium model from the simple CAPM that he rejected.

Intervener submissions

AMPC/BCOAPO characterize Dr. Booth's Operation Twist adjustment as an adjustment to the risk free rate. AMPC/BCOAPO calculate Dr. Booth's risk free rate plus an adjustment for abnormal conditions to be 2.75 percent plus 1.3 percent for the Operation Twist adjustment, resulting in a "proxy risk-free rate of 4.0 %." AMPC/BCOAPO submit this risk free rate plus an adjustment for abnormal conditions is a proxy for the rate used by investors in trading off risk versus return, similar to AON Hewitt's long run target bond yield of 4.21 percent.[239]

CEC recommends 2.75 percent as the risk free rate and submits:

- It is not reasonable to utilize a three-year average for a 1 year rate;[240]
- Forward looking expectations are already captured in the current forecast of long bond yield;[241]
- It is reasonable to expect the market risk premium to decline if the bond yields are expected to increase in the future given the inverse relationship between market equity returns and bond yields.[242]

CEC accepts Dr. Booth's Operation Twist adjustment which indicates current forecast in long Canada yields are "at least 1.3 % too low."[243]

FEI reply submission

With respect to Mr. Coyne's use of the 2016 to 2018 Consensus Economics forecast, FEI submits:

- Mr. Coyne's approach to addressing the need to compensate for the impact of massive global bond buying by central banks does not assume a three-year test period, rather Mr. Coyne uses the forecast long Canada bond yield to establish a normalized, forward-looking bond yield that reflects changes in the long Canada bond over the next few years;
- Both experts normalize the risk free rate using a different methodology but end up in a similar place i.e. Mr. Coyne's forecast bond yield of 3.68 percent vs. Dr. Booth's proxy risk free rate of 4.05 percent; and

[238] FEI Final Submission, p. 92.
[239] AMPC/BCOAPO Final Submission, pp. 45, 53.
[240] CEC Final Submission, p. 23.
[241] CEC Final Submission, p. 23.
[242] CEC Final Submission, p. 24.
[243] CEC Final Submission, p. 40.

- Although it is true that current bond yields incorporate forward expectations of interest rates, as submitted by CEC, interest rates are constantly shifting due to changing economic conditions. As a result, the interest rate at a single point in time may not be reflective of future market conditions.[244]

FEI points to Dr. Booth's oral testimony that the Operation Twist adjustment should be reduced to about 60 to 80 basis points is not consistent with his written evidence in which he describes his 130 basis point adjustment as the "minimum" required adjustment to compensate for the downward effect of government bond buying programs. Further, his support for the adjustment is based on one sample, Canadian Utilities Limited.[245]

Commission determination

The Panel notes that with respect to determining the appropriate risk free rate and an adjustment for abnormal conditions to input into a CAPM estimate, both Mr. Coyne and Dr. Booth:

i) Rely on Consensus Economics forecasts of the 30-year Government of Canada bond yield as the risk-free rate;

ii) Are very close in their estimates of 10-year and 30-year yield spreads; and

iii) Agree on the need to add an additional adjustment to the CAPM to compensate for abnormal conditions in the bond markets resulting from the impact of global bond buying programs.

The Panel recognizes that a risk premium model or CAPM is based on the assumption that current yields are being determined by investors trading off risk and return in a functioning market. The Panel also agrees capital market conditions are similar to 2012 and accordingly, an adjustment for abnormal conditions continues to be reasonable in the current market conditions.

With respect to Mr. Coyne's use of an average of 2016 to 2018 forecast rates to estimate a risk free rate, the Panel is not persuaded that this simple averaging of the forecast rates for this time period results in a supportable "equilibrium or normalized" risk free rate. We accept the position put forward by CEC that current predictions of bond yields already reflect expectations and therefore the current bond yields should be used. While the Panel does not agree with Mr. Coyne's approach to adjusting the risk free rate, we do acknowledge that this is his attempt to adjust for abnormal conditions.

The Panel notes that in the 2013 GCOC Decision, the Commission accepted Dr. Booth's Operation Twist adjustment and Dr. Booth currently uses a consistent methodology in his prepared testimony with the exception of averaging the 2015 spread to address the volatility in the 2015 spread. With respect to his oral testimony that the Operation Twist adjustment should be reduced, the Panel agrees with FEI that reference to a sample on one utility's preferred shares (Canadian Utilities Inc.) as well as the lack of any other detailed analysis related to the predominance of rate reset preferred shares in the index provides insufficient support for a 60 to 70 basis point reduction in Dr. Booth's Operation Twist adjustment. The Panel also notes that AMPC/BCOAPO and CEC both accept Dr. Booth's original 1.3 percent adjustment.

Although the expert witnesses differ in their approach, they both agree on the need for an adjustment in the CAPM to compensate for abnormal conditions in the bond markets resulting from the impact of global bond

244 FEI Reply Submission, pp. 52–55.
245 FEI Reply Submission, pp. 17–18.

buying programs. While the expert witnesses differ in their approach and given there is no precise answer, the Panel takes comfort in the fact they end up with similar estimates. **Accordingly, the Panel, using its best judgment, finds a risk free rate plus an adjustment for abnormal conditions in the range of 3.8 to 4 percent is reasonable for use in the CAPM.**

5.2.3.3 Market risk premium (MRP)

Estimate of market risk premium

Mr. Coyne used a MRP of 7.6 percent in his CAPM, based on an ex-ante (forward-looking) and an ex-post (historical average) derivation of the MRP and using an average of both the Canadian and US equity risk premiums to derive a combined North American equity risk premium as follows:

Table 5.4: Market Risk Premium Values[246]

	Canadian MRP	U.S. MRP
Historical MRP	5.6%	7.0%
Forward-looking MRP	9.8%	8.1%
Average	7.6%	

Mr. Coyne states it is appropriate to combine and average US and Canadian equity risk premiums because the equity markets in the US and Canada are "more similar than not, and there is no reason to expect a divergence in market risk premiums going forward."[247]

Dr. Booth estimates the MRP of common equities over long-term Canada bonds at 5.0 to 6.0 percent using historical Canadian capital market history "going back to 1924 so [the estimate] encompasses periods very similar to today, such as the bleak 1930s of slow growth and falling prices, as well as booms and serious inflation problems such as the 1970's." Dr. Booth also gives weight to US data.[248]

5.2.3.3.1 Use of income or total returns in the derivation of the historical MRP

Mr. Coyne determines his ex-post MRP based on the arithmetic average of historical risk premia: for Canada using Morningstar Direct from 1919 through 2011 and Duff and Phelps thereafter and for the US using Duff & Phelps from 1926 onwards.[249] Mr. Coyne uses estimates of the total return on equities over the income return on bonds[250] consistent with the Ibbotson® SBBI® Valuation Yearbook since in his view, this represents the truly risk free rate.[251]

Dr. Booth states that he suspects the difference between his and Mr. Coyne's Canadian MRP estimates results from Mr. Coyne's use of bond yields rather than bond returns which Dr. Booth uses in his estimate. In Dr.

[246] Exhibit B-1, Appendix B, p. 49.
[247] Exhibit B-1, Appendix B., p. 49.
[248] Exhibit C7-7-2, pp. 39–40.
[249] Exhibit B-1, Appendix B, pp. 45–46.
[250] Oral Hearing Transcript Volume 1, p. 195.
[251] Oral Hearing Transcript Volume 1, p. 198.

Booth's view, it is necessary to subtract bond returns from equity returns to estimate the market risk premium and using bond yields which are not returns "ignores the fact that the equity market reflects interest rate changes, whereas the bond return then does not."[252] Dr. Booth also states:

> It is methodologically incorrect to use yields in risk premium analyses, which is presumably why the CIA [Canadian Institute of Actuaries] does not provide that data. Until relatively recently Dr. Booth had never seen an analyst using yields in a risk premium analysis.[253]

Dr. Booth takes the position it is not acceptable to base a risk premium on the subtraction of a yield from a return, since the equity return will reflect changes in interest rates but the bond yield will not.[254]

Intervener submissions

AMPC/BCOAPO submit Mr. Coyne's use of only the income return on bonds is wrong because it compares distinctly different return types and overstates the result because total returns on bonds have been lower than income returns and the differences can add as much as 1.0 percent to the calculated MRP.[255]

CEC's argument is similar to AMPC/BCOAPO's position.[256]

FEI reply submission

With respect to use of the total return or the income return on Canada long bond yields, FEI submits Mr. Coyne has used the appropriate approach as follows:

- The income returns remove the components of the government bond total return that are not risk free and represent a truly risk free rate;
- Ibbotson and Duff & Phelps provide risk premium calculations based on the income portion of the bond yield. Mr. Coyne uses this data in his analysis; and
- Mr. Coyne sites the 2013 Ibbotson® SBBI® Valuation Yearbook which concludes that the income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[257]

5.2.3.3.2 Use of a forward-looking MRP estimate

With respect to use of historical data, Mr. Coyne's view is the longer the averaging period used, the less responsive the data is to current conditions and in the current market conditions, the historical average will understate the current market risk premium.[258] Mr. Coyne states this is the reason he incorporated a forward-looking into his MRP analysis.[259]

[252] Exhibit C7-9, BCUC IR 11.1.
[253] Exhibit C7-8, FEI IR 11.3.
[254] Exhibit C7-8, FEI IR 10.3.
[255] AMPC/BCOAPO Final Submission, p. 8.
[256] CEC Final Submission, p. 31.
[257] FEI Reply Submission, pp. 56–57.
[258] Exhibit B-1, Appendix B, p. 47.
[259] Exhibit B-1, Appendix B, p. 47.

In his ex-ante MRP, Mr. Coyne uses a constant growth DCF methodology to determine the implied expected market return using the S&P/TSX Composite Index for Canada and for the S&P 500 index for the US[260] and he subtracts his forecast risk free rate from the derived expected market returns to arrive at his forward-looking equity risk premia results of 9.78 percent and 8.08 percent, respectively, for Canada and the US[261] In his view, these results "suggest that a pure historical estimate is too low in today's low interest rate environment."[262]

Mr. Coyne's methodology results in the use of an expected constant growth rate of 10.02 percent for the Canadian market and 9.66 percent for the US market.[263] In contrast, Dr. Booth's estimates of the DCF for the Canadian and US markets are set out in Table 5.5.

In response to a request in the oral hearing, Mr. Coyne also prepared a calculation of his forward-looking MRP using a multi-stage DCF resulting in an estimated MRP of 5.49 percent compared to the 7.6 percent derived from including his constant growth model in his primary analysis.[264] Mr. Coyne views this as an "anomalous result" in that current all-time low bond yields should result in market risk premium that is higher than the long-term average, especially given the inverse relationship between interest rates and the market risk premium.

Dr. Booth questioned the credibility of Mr. Coyne's constant growth MRP estimate because it is based on short-term analyst expectations which "are known to be biased" and include average growth rate estimates that exceed "any plausible long run growth rate for the economy." In Dr. Booth's view, Mr. Coyne's basic approach is incorrect as it is only appropriate to use the constant growth model for the overall economy or low risk stocks such as utilities and not for all the firms in the TSX Composite Index.[265]

FEI submits that Mr. Coyne has appropriately used forward-looking data based on the following reasons:

- The use of forward-looking data is necessary to mitigate the inability of long-term data to respond to changes in market conditions;
- The use of only historical MRP data may not properly reflect the current expectations of investors; and
- Mr. Coyne's ex-ante MRP is lowered by the use of his forecast of the 30-year bond yield (3.68 percent) compared to the result if the 30-year bond yield at August 31, 2015 (2.23 percent) was used.[266]

<u>Intervener submissions</u>

AMPC/BCOAPO submit that Mr. Coyne's ex-ante MRP estimates based on constant growth DCFs are not credible. AMPC/BCOAPO prefer Mr. Coyne's adjustment of his model to a multi-stage DCF model and submit the MRP calculation of 5.39 percent for Canada and 3.96 percent for the US are more in line with historical estimates and the independent survey results.[267]

[260] Exhibit B-1, Appendix B, pp. 45–46.
[261] FEI Final Submission, p. 93.
[262] Exhibit B-1, Appendix B, p. 48.
[263] Exhibit B-4, Appendix B, Exhibit JMC-4, Schedule 1 and 2.
[264] Oral Hearing Transcript Volume 3, pp. 486–488.
[265] Exhibit C7-9, BCUC IR 11.1.
[266] FEI Final Submission, p. 93.
[267] AMPC/BCOAPO Final Submission, pp. 52–53.

CEC submits that the forward-looking evidence presented by Mr. Coyne should not be accepted by the Commission.[268]

FEI reply submission

FEI submits that Mr. Coyne's use of a forecast Canada bond yield reduced his ex-ante MRP estimate and similarly he used a forecast rate in his regression analysis.[269]

5.2.3.3.3 Methods to test the reasonableness of MRP estimates

Mr. Coyne tested his MRP estimates by conducting a regression analysis on long Canada bond yields and annual market risk premiums calculated by Morningstar Ibbotson through 2011 and Duff & Phelps after 2011, removing the effects of the global financial crisis in 2008 on the basis that this was an anomalous event. Mr. Coyne notes his "analysis yielded a statistically significant value at the 85 percent confidence level, and in my opinion is informative of the relationship between bond yields and market risk premiums."[270] Mr. Coyne uses the results of his regression formula to calculate a MRP of 10.09 percent using his estimated long Canada bond yield of 3.68. Mr. Coyne concludes that this supports his 7.6 percent MRP estimate as being reasonable and reflects the current low interest rate environment.[271]

In response to CEC IR 2.46.1, Mr. Coyne re-ran the regression equation used to test his MRP estimates without isolating the effects of the 2008 global financial crisis resulting in a reduction of MRP to 7.46 percent. Overall, Mr. Coyne finds the results of the model requested by CEC "to be inferior to its original analysis."[272] Mr. Coyne also refined his criteria and removed other anomalous outliers and this produced MRP result of 8.5 percent accompanied by a higher level of statistical significance.[273]

Dr. Booth uses survey results by Professor Fernandez as a confirmation that his MRP range is in line with the views of other finance professionals and states the survey results support his estimates.[274]

FEI submits that Mr. Coyne's regression analysis on his MRP estimate yielded a statistically significant value and provides evidence that the MRP and bond yields are inversely related. FEI also reiterates Mr. Coyne's calculation, noting that applying his MRP of 7.6 percent yields an ROE of 10.19 percent when a proxy group beta average of 0.65 was used and when the Canada long bond is 3.68 percent. The ROE estimate is reduced to 9.78 percent when the Canada long bond is equal to the August 31, 2015 value of 2.23 percent.[275]

Intervener submissions

AMPC/BCOAPO submit that Dr. Booth's estimate based on historical data is supported by the November 2015 survey by Professor Fernandez against which Dr. Booth checked his data. In AMPC/BCOAPO's view this survey data represents a large sample of analysts, companies and finance professors estimating the MRP in various

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[268] CEC Final Submission, p. 30.
[269] FEI Reply Submission, p. 58.
[270] Exhibit B-1, Appendix B, p. 49.
[271] Exhibit B-1, Appendix B, p. 50.
[272] Exhibit B-12, CEC IR 46.1.
[273] Exhibit B-12, CEC IR 46.8.1.
[274] Exhibit C7-7-2, pp. 39–40.
[275] FEI Final Submission, p. 94.

markets. AMPC/BCOAPO also submit that Dr. Booth's results are comparable to independent and credible forecasts including TD Economics, AON Hewitt and Mercer[276] and the estimates used by Mr. Coyne calculating his MRP exceed the expectations of each of the independent forecasters for the market as a whole.[277]

CEC endorses Dr. Booth's conclusions on the MRP[278] and raises additional issues with Mr. Coyne's evidence as follows:

- The effects global financial crisis of 2008 should not have been isolated in Mr. Coyne's regression analysis;
- The weaker F-statistics cited by Mr. Coyne in the regression analysis reflecting 2008 data are not relevant;[279]
- The results of the revised regression analysis may simply be indicative of a generally poor correlation between the variables and as a result less confidence should be applied to the relationship between bond yields and the annual market risk premiums;[280] and
- CEC submits 7.46 percent best represents the long-term average.[281]

<u>FEI reply submission</u>

FEI submits that each of the regression equations Mr. Coyne was asked to perform by CEC continues to corroborate, rather than undermine, his 7.6 percent MRP. FEI also submits Mr. Coyne arrived at his MRP estimate first and used regression to test its reasonableness and the regression result would have supported an even higher MRP.[282]

In reply to Dr. Booth's use of Professor Fernandez's survey results as a confirmation that his MRP range is in line with the views of other finance professionals, FEI submits AMPC/BCOAPO relied primarily on a Fernandez Survey to support their MRP range and there are a number of shortcomings of the study, including the limited number of estimates provided for Canada and the wide dispersion of those estimates.[283]

Commission determination

With respect to the expert's estimates of MRP, the Panel considered the following areas:

a) Use of income or total returns
b) Use of forward-looking MRP estimates
c) Methods used to test whether MRP estimates were reasonable

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276 AMPC/BCOAPO Final Submission, pp. 50–51.
277 AMPC/BCOAPO Final Submission, p. 52.
278 CEC Final Submission, p. 38.
279 CEC Final Submission, p. 32.
280 CEC Final Submission, p. 32.
281 CEC Final Submission, p. 34.
282 FEI Reply Submission, pp. 58–60.
283 FEI Reply Submission, p. 60.

a) Use of income or total returns

The Panel notes that both experts use similar historical periods and give weight to US data. The Panel observes that Mr. Coyne's average historical MRP is 6.3 percent, compared to Dr. Booth's average of 5.5 percent. Dr. Booth's attributes this difference to Mr. Coyne's use of income returns on bonds rather than total returns which Dr. Booth uses in his estimate. AMPC/BCOAPO also submit the use of income returns can add as much as 1.0 percent to the calculated MRP. The Panel accepts that the difference between the historical averages of the two experts is attributed to this difference in methodology. While Dr. Booth considers this approach to be methodologically incorrect and one that he has only observed recently, he does not provide any further evidence to support his view. In the Panel's view, the differences in the positions of the expert witnesses should be examined further in the next cost of capital proceeding. While not endorsing this approach, the Panel accepts that Mr. Coyne's position is supported by third party evidence including:

- The reference to the 2013 Ibbotson® SBBI® Valuation Yearbook indicating the income return on bonds represents the truly risk free rate; and
- The use of the income returns by Ibbotson and Duff & Phelps in their risk premium calculations.

Given the use of income or total returns is the only clearly identified difference between the two historical MRP estimates, **the Panel accepts Mr. Coyne's estimate of historical MRP of 6.3 percent calculated giving equal weight to Canadian and US historical MRP.**

b) Use of forward-looking MRP estimates

The Panel notes that Dr. Booth is satisfied to base his estimates on historical data dating back to 1924 and encompassing periods he considers to be very similar to today and confirms his position by comparing them to the Fernandez Survey consisting of current expectations of finance professionals. Mr. Coyne's view is the historical average will understate the current market risk premium given current market conditions. This is why he incorporated a forward-looking approach into his analysis. The Panel notes that while the approaches of the experts differ, both experts agree some consideration of forward-looking expectations and data is necessary to appropriately estimate MRP. **Therefore, the Panel finds that some weight should be given to forward-looking MRP estimates.**

The Panel agrees with the interveners' concerns over Mr. Coyne's use of a constant growth DCF methodology to determine the implied forward-looking expected market return and is concerned the growth rates he uses in these models overstate the MRP. The Panel also put little weight on the multi-stage DCF values Mr. Coyne presented in response to the undertaking at the oral hearing because there was not an opportunity to fully explore it within the oral hearing. Further, the Panel notes Mr. Coyne's lack of confidence in the "anomalous" results given that the current all-time low bond yields should result in market risk premium that is higher than the long-term average considering the inverse relationship between interest rates and the market risk premium. **Accordingly, the Panel finds it can place little weight on Mr. Coyne's constant growth or multi-stage DCF estimates of the forward-looking MRP.**

While Dr. Booth estimates the MRP of common equities over long-term Canada bonds at 5.0-6.0 percent using historical Canadian capital market history, the Panel takes note of Dr. Booth's constant growth DCF estimates for the market as a whole as set out in Table 5.5, where he estimates an average of 8.75 percent for the Canadian market as a whole and 9.6 percent for the US market as a whole based upon his estimates of sustainable growth rates. Dr. Booth's sustainable growth rates average 5.25 percent and 6.91 percent for Canada and US markets, respectively. In comparison, Mr. Coyne's constant growth DCF estimates for the market as a whole using a constant growth model are 10.02 percent for the Canadian market and 9.66 percent for the US market. The Panel considers a reasonable forward-looking growth rate to be somewhere between the estimates of the two experts. **Therefore, with the application of judgement, the Panel accepts 6.5 to 7.5 percent as a reasonable range of estimates for a forward-looking MRP.**

Mr. Coyne gives equal weight to his historical and forward-looking MRPs estimates, while Dr. Booth uses the Fernandez Survey as a check for his historical MRP estimates. As noted above, the forward-looking estimates for the market as a whole reflect different approaches and a wide range of results, none of which were carefully examined in this proceeding. Further, in the Panel's view, all other things being equal, there is a trade-off between relevance of forwarding-looking data and the reliability of historical data and given the higher reliability of the historical estimates, **the Panel places more weight on historical estimates of MRP and less weight on forward-looking MRP estimates and accepts a range of 6.3 to 7.0 percent as a reasonable estimate of MRP.**

With respect to the use of the equity market return expectations of pension funds and other investment managers including TD Economics, AON Hewitt and Mercer, to the extent they are available, the Panel considers this information may represent a relatively direct view of forward-looking returns expected from the equity markets and can be useful as a check of the expert witnesses' forward-looking MRP estimates. The evidence on the record indicates that pension and investment managers appear to be forecasting returns on the Canadian equity markets in the range of approximately 8 percent to 9 percent on an arithmetic basis.

c) Methods used to test whether MRP estimates were reasonable

With respect to CEC's submissions related to Mr. Coyne's regression analysis, the Panel accepts that Mr. Coyne does not use this approach to develop a point estimate of MRP but rather as a means to corroborate his estimate of MRP. The Panel agrees with FEI that each of the regression equations Mr. Coyne was asked to perform by CEC do not undermine his 7.6 percent MRP.

The Panel does note FEI's view that there are a number of shortcomings of the Fernandez Survey, including the limited number of estimates provided for Canada and the wide dispersion of those estimates. Accordingly, the Panel finds that this survey is not an appropriate tool on which to base an estimate of the current market expectations for MRP but the Panel does accept that its results provide some corroboration of the historical MRPs of the two experts.

5.2.3.4 Beta and beta adjustments

Beta estimates

Beta is a measure of systematic risk that represents the risk of a security relative to the market. Beta is an adjustment to the MRP to account for the degree to which the individual stock contributes to the market risk. With respect to beta, the issue the Panel needs to decide is the appropriate range of the adjustment to raw or historical beta estimates reflective of current market expectation.

Mr. Coyne's beta calulations are adjusted to the market mean of 0.65 for his Canadian proxy group and 0.78 for his US proxy group. Mr. Coyne uses estimates from:

(1) Value Line for the US gas distribution proxy group which reports historical beta based on five years of weekly stock returns and uses the New York Stock Exchange as the market index.

(2) Bloomberg for the Canadian proxy group which Mr. Coyne set to five years of weekly returns on the S&P 500 or S&P/TSX Composite Index.

Both Value Line and Bloomberg betas are adjusted to compensate for the tendency of beta to revert towards the market mean of 1 over time.[284]

Based on his analysis, Dr. Booth judges the relative risk of Canadian regulated utilities to be 45 to 55 percent of the market as a whole.[285] Dr. Booth uses five years of monthly data and estimates each beta using the standard formula covariance (Y, X) divided by Population variance (X).[286] He states that the recent history of the beta coefficients of Canadian utilities is in the approximate range of 0.30 to 0.45 and attributes the higher end of this range to the post-financial crisis and the internet bubble.[287] In Dr. Booth's view, as interest rates increase back to normal levels, he expects their betas to revert back to their long-run average of 0.45 to 0.55.[288]

Dr. Booth compares his beta estimates of seven Canadian utility holding companies estimates by RBC, Yahoo, and Google.[289] He notes that these sources do not indicate that their betas are adjusted.[290] He also considered the history of US firms as a comparison and points out they have a higher beta difference of .10 compared to Canadian utilities.[291]

5.2.3.4.1 The appropriate adjustment to beta

Mr. Coyne cites the empirical evidence, including the Blume studies, supporting a beta adjustment and outlines the statistical purpose for adjusting toward the market average of 1.0. In Mr. Coyne's evidence, he explains the reason to adjust betas toward 1.0 as follows:

> Betas that are below the market average of 1.0 tend to have negative the error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted betas toward 1.0 in an effort to improve forecasts. Because current stock prices reflect expected risk, one must use an expected beta to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta.[292]

Mr. Coyne presented an analysis to demonstrate it is apparent that unadjusted betas do a poor job of estimated expected returns, as follows:

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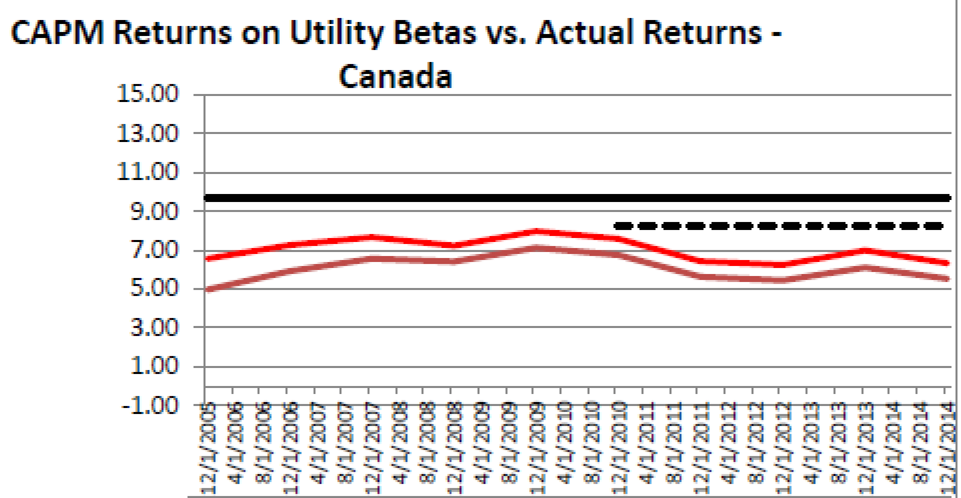
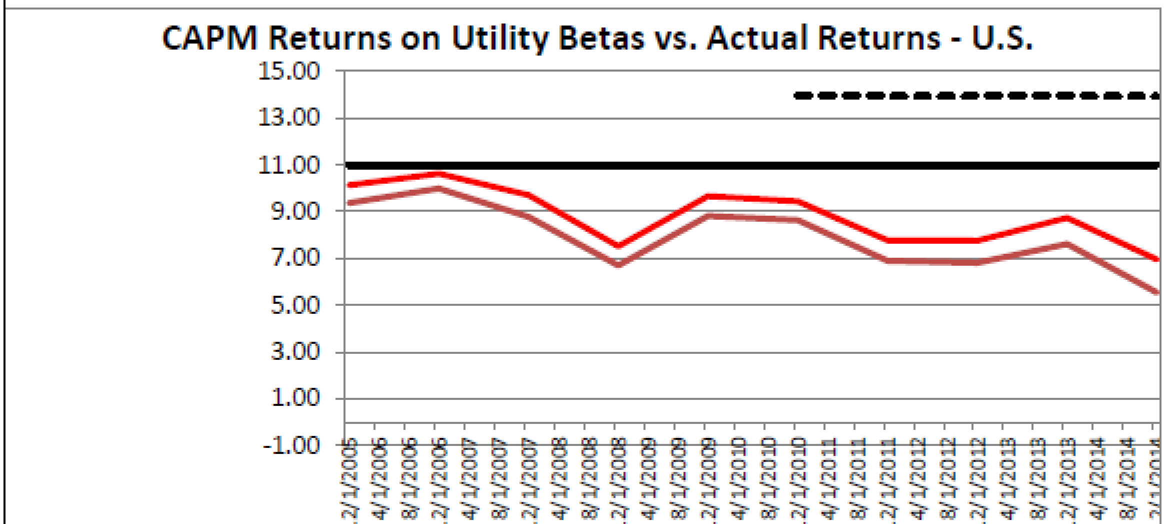
[284] Exhibit B-1, Appendix B, p. 42.
[285] Exhibit C7-7-2, p. 40.
[286] Exhibit C7-7-2, Appendix C, p. 6, Schedule 2.
[287] Exhibit C7-7-2, p. 40.
[288] Exhibit C7-7-2, Appendix C, p. 6.
[289] Exhibit C7-7-2, Appendix C, p. 8.
[290] Exhibit C7-7-2, Appendix C, p. 10.
[291] Exhibit C7-7-2, Appendix C, p. 6.
[292] Exhibit B-1, Appendix B, pp. 42–43.

Figure 5.1: Comparison of CAPM Returns on Utility Betas vs. Actual Returns[293]



	12/30/2005	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/30/2011	12/31/2012	12/31/2013	12/31/2014
Adjusted Betas Canada	6.33	6.98	6.25	6.42	7.58	7.97	7.23	7.67	7.26	6.55
Raw betas	5.52	6.11	5.44	5.63	6.75	7.12	6.41	6.55	5.92	4.96
10-yr Actual Returns	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69	9.69
5-yr Actual Returns	8.25	8.25	8.25	8.25	8.25					



	12/30/2005	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/30/2011	12/31/2012	12/31/2013	12/31/2014
Adjusted Betas U.S.	6.95	8.73	7.75	7.76	9.43	9.65	7.52	9.70	10.63	10.12
Raw betas	5.55	7.61	6.80	6.90	8.63	8.81	6.69	8.78	9.98	9.36
10-yr Actual Returns	10.98	10.98	10.98	10.98	10.98	10.98	10.98	10.98	10.98	10.98
5-yr Actual Returns	13.93	13.93	13.93	13.93	13.93					

[293] Exhibit B-8, AMPC-Concentric IR 5.4.

Mr. Coyne states the analysis shows that even when applying betas adjusted towards the market mean of 1.0, modifications must be made to the CAPM to reasonably project utility equity returns.[294]

Mr. Coyne also supports his position by stating "the Value Line and Bloomberg methodologies are widely accepted and utilized by financial analysts, investors, corporations, and broadly accepted by U.S. regulatory commissions" referencing a similar finding in the Brattle Group Report.[295]

Mr. Coyne testified that his adjustment methodology was not an issue in the OEB Consultative Process on Cost of Capital and the Board did not take exception to his use of adjusted Value Line and Bloomberg betas.[296] He states he is not aware of a single US state or federal regulatory jurisdiction that takes exception to the use of this adjustment methodology and that this issue only comes up in Canadian regulatory proceedings in which Dr. Booth is a witness.[297] In his opinion, the prevailing wisdom on the required adjustments to utility betas is to use the Blume adjustment.[298]

With respect to adjusted betas, in Dr. Booth's view, utility witnesses frequently adjust toward the overall market average of 1.0 which is the level recommended by Blume for the "whole universe of stocks." He states that low beta estimates for utilities "do not mean they are under-estimates, since utility betas are perennially low due to their low risk"[299] and that there is no evidence of these estimates going towards 1.0.[300] Dr. Booth also discusses the work of Gombola and Kahl who he states demonstrate that utility betas are better mechanically adjusted to their grand mean of around 0.50. Dr. Booth finds that such an adjustment makes very little difference to his estimates. Recognizing that betas need to be adjusted, Dr. Booth prefers to "use judgement constrained by the actual historic evidence."[301]

With respect to the use of Merrill Lynch and Value Line to provide adjusted betas, Dr. Booth notes these are US data providers and companies in Canada such as the Financial Post, RBC and the Globe & Mail do not adjust betas and this approach enables the user to apply judgment. He stated he has no issue with adjusting betas but has a problem with adjusting them towards 1.0.[302]

FEI submits that Mr. Coyne's approach to beta and his results are to be preferred based on the following:[303]

- Both Value Line and Bloomberg betas already incorporate the "Blume adjustment";
- Mr. Coyne's own data analysis, the Brattle Group Report findings and other empirical studies have shown that stocks with low betas, including utility stocks, have achieved returns higher than predicted by the traditional CAPM;
- the Blume adjustment is widely used and accepted in every regulatory jurisdiction without debate, except those jurisdictions in which Dr. Booth testifies;

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[294] Exhibit B-8, AMPC-Concentric IR 5.4.
[295] Exhibit A2-3, Brattle Group Report, May 31, 2012, pp. 15–16.
[296] Oral Hearing Transcript Volume 2, pp. 228–230.
[297] Exhibit B-16, Rebuttal Evidence of Mr. Coyne, p. 28.
[298] Exhibit B-16, Rebuttal Evidence of Mr. Coyne, p. 28.
[299] Exhibit C7-7-2, Appendix C, p. 7.
[300] Oral Hearing Transcript Volume 3, p. 577.
[301] Exhibit C7-7-2, Appendix C, pp. 8–9; T3:572, 580.
[302] Oral Hearing Transcript Volume 3, pp. 691–692.
[303] FEI Final Submission, pp. 96–98.

- Adjustment to the grand mean of utility betas is not a suitable substitute for the Blume adjustment because it does not sufficiently compensate for the negatively biased result for low beta firms and does recognize the additional risk inherent in the calculation of beta for interest-rate sensitive firms; and
- Dr. Booth also adjusts his raw betas and has used the same generic beta adjustment for at least ten years.

Intervener submissions

AMPC/BCOAPO make the following submissions in support of Dr. Booth's approach to determining beta:[304]

- Dr. Booth's determination of the relative risk of a Canadian utility of 45 to 55 percent is a generous beta relative to the much lower utility betas that have been experienced in recent years;
- No other Canadian regulatory board has accepted betas adjusted towards 1.0;
- Analysts do not generally adjust betas towards a mean of 1.0 as evidenced by sources examined by Dr. Booth, including RBC, Google, Yahoo, the Globe and Mail and the Financial Post;
- Mr. Coyne's calculation of Canadian beta adjusted to the industry average of 0.57 is very close to the upper end of Dr. Booth's range and the bottom of Dr. Booth's range is comparable to Mr. Coyne's raw Canadian beta of 0.47;
- In the last 22 years, Canadian utility betas have not reached the .60 used by the Commission in 2013; and
- Adjusting beta to the average beta of utilities stocks is "best practice" as this is more indicative measure of where utility stock betas are likely to average over time.

CEC supports Dr. Booth's approach to beta and notes that Mr. Coyne's incorporation of the US utilities data results in a higher beta than would be applicable to Canadian utilities.[305]

FEI reply submission

FEI submits that Mr. Coyne's use of Blume-adjusted betas produces a more reasonable result and should be preferred. In its reply submission, FEI responds to the interveners submissions as follows:[306]

- To respond to its interpretation of AMPC/BCOAPO's characterization of the Blume adjustment, FEI reiterates that the Blume adjustment is:
  - (a) Not an adjustment to 1.0 but rather directionally toward 1.0 by giving 2/3 weighting to raw betas and 1/3 weight to the market mean of 1.0.; and
  - (b) Does not mean that there is an expectation that betas will reach 1.0.
- In the 2013 GCOC Decision, the Commission found that none of the positions fully explained the beta values and accepted an intermediate beta of 0.60, however in the current proceeding, there is significant evidence on the record to warrant placing greater weight on Blume-adjusted data including:
  - (a) the Blume studies;
  - (b) excerpts from Dr. Morin's textbook;
  - (c) the Brattle Group Report;

[304] AMPC/BCOAPO Final Submission, pp. 46–49.
[305] CEC Final Submission, pp. 28–29.
[306] FEI Reply Submission, pp. 67–72.

(d) the Fernandez studies;

(e) the standard adjustment methodology employed by Value Line, Bloomberg and Merrill Lynch for equity return calculations;

(f) Mr. Coyne's own study results confirm that raw betas, and even Blume-adjusted betas, are understated;

(g) a list of additional studies that Mr. Coyne was asked to provide by way of undertaking;

(h) Mr. Coyne's evidence that Blume adjusted betas are widely used and accepted by regulators; and

(i) The betas used in the pension reports relied on by Dr. Booth as support for his MRP.

- The riskiness of utility stocks relative to the market should not be used as a basis for determining betas and the lower volatility of these stocks only suggests that betas should be less than one. Further, one would expect raw betas to be below adjusted betas for low beta stocks and the fact that the betas are lower is not an indication of whether raw betas need to be adjusted.

Commission determination

Based on the evidence presented by both experts, the Panel finds it is appropriate to adjust historical betas to estimate expected returns using the CAPM. Both experts and all parties agree that an adjustment to historical raw beta is required.

The issue for the Panel to determine is what the appropriate adjustment to raw historical betas should be. In the 2013 GCOC Decision, the Commission found that none of the positions fully explained beta and on that basis, accepted a beta representing the range of reasonable estimates presented. The Panel notes AMPC/BCOAPO's statement that "there is no historical statistical evidence supporting the Commission's use of a beta of 0.60"[307] with reference to the 2013 GCOC Decision. The Panel also notes FEI's argument that there is significant evidence on the record to consider the appropriateness of placing greater weight on Blume adjusted data.

To determine the amount of the beta adjustment, the Panel considers the appropriateness of using an adjustment to the average beta of utility stocks. Both AMPC/BCOAPO and CEC support such an adjustment. While Dr. Booth refers to the Gombola and Kahl study and considers the effect of adjusting to the average beta of utility stocks, he recommends that recent historical betas be adjusted upward to their historical range reflecting normal market risk. Dr. Booth prefers the use of judgment constrained with historical evidence over simply adjusting to the average of utility stocks. Mr. Coyne's view is such an adjustment does not sufficiently compensate for the negatively biased result for low beta firms and does recognize the additional risk inherent in the calculation of beta for interest-rate sensitive firms. **Given that neither expert endorses the adjustment of beta to the average of utility stocks, the Panel finds there is little evidence in this proceeding to support an adjustment to the average beta of utility stocks.**

The Panel does not accept it should rely solely on Dr. Booth's judgement without stronger empirical corroborating evidence to support his beta adjustments. Accordingly, **Panel finds that it can place only limited weight on Dr. Booth's beta estimates.**

[307] AMPC/BCOAPO Final Submission, p. 48.

With respect to the use of the Blume adjustment, the Panel notes Mr. Coyne's evidence presented in Figure 5.1 above which in his view, shows that unadjusted betas do a poor job of estimating expected returns and Blume adjusted betas still understate the actual return but the result is closer than using raw betas. The Panel is of the view that this analysis confirms, consistent with the Fernandez beta study Mr. Coyne refers to in his rebuttal evidence, the beta calculated using historical data is not a good approximation of a company's beta. In the Panel's view, this analysis confirms that an adjustment is needed but does not provide evidence of what the adjustment to beta should be. The Panel is also concerned that given the disruption in the capital markets during the period presented and recent merger and acquisition activity[308] in the industry there may be confounding factors impacting the results of the analysis.

The Panel acknowledges Mr. Coyne's view that the Blume adjusted Value Line and Bloomberg data he uses are used and accepted. On the other hand, Dr. Booth's evidence shows some data providers do not use this method. Further, the Panel considers that findings of the Brattle Group indicate some variation in practice:

> Beta estimates are provided by many data services for Canadian, American and other traded companies. The most common methodology to estimate betas is to use the most recent five years of weekly or monthly return data. These betas <u>may</u> then be adjusted towards one as adjustment for sampling reversion that was first identified by Professor Marshal Blume (1971, 1975).[309]

The Panel also notes Mr. Coyne's testimony that the Blume methodology is a supported and widely used methodology utilized by financial analysts, investors and corporations. However, considering the survey results included in the Fernandez beta study Mr. Coyne refers to in his rebuttal evidence, the Panel considers the justification for doing so is likely more practical than theoretical.

The Panel notes that none of the studies Mr. Coyne refers to in Exhibit B-31 specifically relates to the behaviour of utility stock betas. The Panel is not persuaded the evidence in this proceeding supports the position that the Blume adjustment applies to utilities in the same way it applies to the market as a whole. The Panel notes this was a point made by Dr. Booth in his evidence.

The Panel has also considered decisions in other jurisdictions. While no other Canadian jurisdiction has previously endorsed the Blume methodology, it is not uncommon to rely on adjusted betas; Mr. Coyne testified US jurisdictions regularly consider or rely on Blume adjusted betas.

Although the methodologies may vary, neither of the experts disagree that some degree of upward adjustment is necessary. The Panel agrees.

The Panel accepts that its task is to estimate beta for a utility stock but as pointed out, there is a lack of empirical evidence supporting the applicability of the Blume adjustment to utility stocks. **Because of this, the Panel finds it can place only limited weight on Mr. Coyne's use of the Blume adjustment as a methodology to adjust historical utility betas.**

- need to read this entire discussion, starting with the rejection of Booth's betas on pdf 78

[308] Oral Hearing Transcript Volume 3, pp. 584–585.
[309] Exhibit A2-3, Brattle Group Report, pp. 15–16. (Emphasis added)

Given that the Panel places only limited weight on the beta estimates of the experts and there has been little change in economic conditions since the last hearing, consistent with the 2013 GCOC Decision, the Panel continues to accept beta estimates representative of the range of estimates presented of approximately 0.6.

5.2.3.5 Dr. Booth's credit spread adjustment

In his evidence, Dr. Booth analyzed the volatility indices and the spread between corporate debt and Canada bonds and concludes that the increase in A credit spread to 191 bps from the typical average for the normal business cycle of 100 bps was caused partially by liquidity problems which have to be disentangled.[310] Dr. Booth recommends 50 percent adjustment to changes in credit spreads or 0.45 percent[311] to adjust the current market effect. Dr. Booth regards this sort of adjustment as converting the CAPM into a conditional CAPM (CCAPM) where the CAPM holds conditional upon the state of the financial markets.[312]

Mr. Coyne's issue with the CCAPM adjustment is that he believes in current market conditions, the default component would be greater than 50 percent, necessitating a higher adjustment.[313]

Intervener submissions

AMPC/BCOAPO reiterated that 0.45 percent adjustment to the CAPM result, as a prudent adjustment is consistent with the objective of ensuring that FEI's fair ROE reflects current capital market conditions.[314] CEC submits Dr. Booth has provided credible evidence with respect to the need for and appropriate calculation of the credit spread adjustment.[315]

Commission determination

The Panel takes no position with respect to the merits of Dr. Booth's recommended credit spread adjustment. **The Panel finds the evidence on the credit spread adjustment is not persuasive enough to warrant a credit spread adjustment.**

5.2.3.6 Appropriate CAPM estimate

Commission determination

In arriving at its overall determination on the CAPM estimate, the Panel recognizes that using a CAPM requires the selection of a number of subjective decisions that can lead to significantly different results. In addition, consistent with the view of the experts, the Panel recognizes the limitations of the model are exacerbated in the current market environment as reflected in the need to modify the risk free rate to adjust for abnormally low bond yields. Recognizing these limitations, the Panel considers it is necessary to use its best judgment to assess the reasonableness of the inputs into the CAPM and to determine an appropriate overall estimate for the model. The Panel will then determine the appropriate weighting to apply to the results under current market conditions relative to the DCF.

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[310] Exhibit C7-9, BCUC IR 13.2.
[311] 91 basis point (191-100) with 50 percent adjustment.
[312] Exhibit C7-9, BCUC IR 13.3.
[313] Exhibit B-18, Mr. Coyne Rebuttal, p. 33.
[314] AMPC/BCOAPO Final Submission, p. 53.
[315] CEC Final Submission, p. 40.

With application of appropriate judgement, the Panel accepts an estimate of approximately 8.0 percent, excluding flotation costs, as the CAPM estimate for the appropriate ROE. The Panel arrives at this determination by drawing together its conclusions on the individual inputs to the CAPM estimates as well as considering the level of uncertainty involved, the requirement to exercise its judgment and considering the conclusions reached in previous decisions. As outlined earlier in Section 5.2.3, the Panel's conclusions with respect to individual inputs to the CAPM are summarized below:

i) A risk free rate plus an adjustment for abnormal conditions in the range of 3.8 to 4.0 percent. This is based on both experts agreeing that an adjustment to the risk free rate is necessary in the current market conditions and that both experts' end up with similar estimates.

ii) MRP in the range of 6.3 to 7.0 percent based on:

   a) Acceptance of Mr. Coyne's historical MRP of 6.3 including the use of income returns as opposed to total returns. This is based on third party evidence supporting his view as well as giving equal weight to Canadian and US historical MRP.

   b) Consideration of forward-looking MRP estimates while placing more weight on historical because of the use of largely untested growth estimates in the forward-looking calculations and the Panel's view that forward-looking data is less reliable than historical estimates.

iii) Beta estimate of approximately 0.6. The Panel considers the views of the parties that an upward adjustment to raw historical betas is necessary but given the lack of empirical evidence supporting their positions, the Panel places no reliance on the adjustment methods used by the experts. Consistent with the 2013 GCOC Decision, the Panel bases it determination on the range of estimates presented with an intermediate value of approximately 0.6.

5.2.4 Discounted cash flow estimates

The DCF model is another tool that is commonly used to estimate the cost of capital. This model works directly with an individual asset's cash flows and price. In estimating cost of equity, the DCF model "derives the opportunity cost of equity determined by the market, without having to model explicitly the market risk-return trade-off that generated the market's opportunity set." As such, the DCF model is based on the recognition that the discounted sum of all future expected dividends results in the current stock price and equates the cost of equity with the expected dividend yield plus the expected growth rate of dividends. Therefore, it derives the opportunity cost of equity as determined by the market.[316]

Like the use of the CAPM, reliance on the DCF model to estimate the cost of equity is not without its issues. Two commonly raised issues with this model are the choice of DCF model to be relied upon and the determination of an appropriate growth rate to be used in the formula. With these in mind, the Panel has identified three areas which need to be explored in determining an appropriate DCF estimate. These are as follows:

i) The value of the constant growth versus a multi-stage approach to using the DCF model.

ii) Guidance the Panel can take from the submissions given the difference in approach to DCF taken by Dr. Booth and Mr. Coyne.

iii) The appropriate weight to place on analyst estimates.

In addition to these considerations and further to Section 5.2.2, the Panel must also address Mr. Coyne's proxy group make-up and determine the relative weight given to them.

[316] Exhibit A2-3, Brattle Group Report, p. 26.

5.2.4.1 Constant growth and multi-stage DCF model variants

There are two types of models which are commonly used for DCF estimates, the constant growth and the multi-stage models. Each of these has been used by the experts in this proceeding.

As outlined by Mr. Coyne, the constant growth DCF model is based on a number of assumptions. These include the following:

- an average growth rate for earnings and dividends which is constant;
- a stable dividend payout ratio;
- a constant price-to-earnings multiple; and
- a discount rate greater than the expected growth rate.[317]

Put simply, the constant growth model yields a cost of equity equaling the expected dividend yield plus the perpetual expected future growth rate for dividends. In implementing this model, the expected dividend, the growth rate and the current stock price must be determined.

Where there is reason to believe that investors do not expect a steady growth rate in perpetuity as an input assumption in the constant growth DCF model, the multi-stage DCF model is another option. As outlined in the Brattle Group Report, the multi-stage DCF model may be appropriate where there is reason to believe investors do not expect a steady growth rate forever, but rather, have different growth rate forecasts in the near term (e.g., over the next five or ten years) converging to a constant terminal growth rate at the end of the near-term (e.g., at the end of five or ten years).[318] A key element of this is the expected growth rate must become and remain constant at some point. However, the choice of an appropriate growth rate is the most controversial part of the DCF model implementation, particularly for the long-term as this has a major effect on the cost of equity estimated by the model. This is further complicated by the fact forecast growth rates are generally unavailable for periods longer than five years. This is important given the Brattle Group Report's statement that "the DCF approach requires that the stable-growth assumption must be reasonable and must be met *within the period for which forecasts are available.*"[319]

Generally, the Brattle Group Report views the DCF approach as being conceptually sound as long as its assumptions are met but in practice, can run into difficulty when those assumptions are so strong and unlikely to correspond to reality. Further, the stability of DCF cost of equity estimates can be a problem across similar companies or over a relatively short time span. The more stable a company or industry the less of a problem such issues pose.[320]

Both Mr. Coyne and Dr. Booth present variants of the DCF model. The following table sets out Mr. Coyne's and Dr. Booth's estimates and variants of the DCF model.

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[317] Exhibit B-1, Appendix B, p. 51.
[318] Exhibit A2-3, Brattle Group Report, pp. 9, 26–27.
[319] Exhibit A2-3, Brattle Group Report, pp. 27–30. (emphasis in original)
[320] Exhibit A2-3, Brattle Group Report, p. 30.

Mr. Coyne and Dr. Booth's use of the DCF Model

Table 5.5 summarizes the expert witnesses' use of the DCF model variants and their estimates.

Table 5.5: Summary of DCF Estimates

Mr. Coyne		
DCF model type	**Specification**	**DCF Estimates**[321]
Constant growth model[322]	• Seven US and five Canadian proxy companies; • Earnings growth rates taken from SNL Financial, Value Line, Zacks and First Call for each company in the Canadian and US proxy group.	Canada: 12.20%[323] US: 9.18%[324] Average: 10.69%
Multi-stage model (selected)[325]	• Same companies and growth data source as constant growth model above; • Estimated company growth for Years 1 to 5; declining to long-term growth in Years 6-10; nominal GDP growth in Year 10+	Canada: 9.32%[326] US: 8.39%[327] Average: 8.86%
Dr. Booth		
DCF model type	**Specification**	**DCF Estimates**
Constant growth model[328]	• Whole Canadian market • Sustainable growth rate range of 4.72 to 5.77%	Approximately 8.75%[329]
Constant growth model[330]	• US S&P 500 firms • Sustainable growth rate 6.91% (average)	Range: 9.04% to 10.14%[331]

[321] Mr. Coyne's DCF ROE estimates include 50 bps flotation allowance and therefore, Mr. Coyne's estimates in the table are 50 bps lower for comparison purposes

[322] Exhibit B-1, Appendix B, p. 5; Exhibit B-1, Appendix B, Exhibit JMC-7, Schedule 1.

[323] Canada: growth rates, depending on the company, range from 4.19% to 13.63%. Average growth rate 8.03%; Exhibit B-1, Appendix B, Exhibit JMC-7, Schedule 1, pg. 2.

[324] US: growth rates, depending on the company, range from 4.75% to 6.95%. Average growth rate 5.65%; Exhibit B-1, Appendix B, Exhibit JMC-7, Schedule 1, pg. 1.

[325] Exhibit B-1, Appendix B, p. 5; Exhibit B-1, Appendix B, Exhibit JMC-7, Schedule 2, Column 10.

[326] Canada: Years 1 to 5 growth range from 4.19% to 13.63% with an average of 8.03%. Year 6 to 10-average 5.98%. Nominal GDP growth in perpetuity is 3.94%; Exhibit B-1, Appendix B, Exhibit JMC-7, Schedule 2, pg. 2.

[327] US: Years 1 to 5 growth rates range from 4.75% to 7.25% with an average of 5.65%. Year 6 to 10-average 5.47%. Nominal GDP growth in perpetuity is 4.55%; Exhibit B-1, Appendix B, Exhibit JMC-7, Schedule 2, pg. 1.

[328] Exhibit C7-7-2, Direct Testimony of Dr. Booth, Appendix D, pp. 6–8.

[329] TSX dividend yield at the end of September 2015 is 3.17%; Long run growth rate in dividends and earnings is 5.35%.

[330] Exhibit C7-7-2, Direct Testimony of Dr. Booth, Appendix D, pp. 9–10.

[331] Current dividend yield on the S&P 500 index: 1.99%; S&P 500 firms retention rate (b) is 52.3% since 1956; S&P 500 firms average ROE is 13. 43% since 1987. Median is 14.07%. Over the same period, the retention rates were 51.5% (average) and 57% (median); Growth rates: 57%*14.07% = ~7.99% (median) 51.5%*13.43% = ~6.91% (average).

Constant growth model[332]	• Eight low risk US utilities • Sustainable growth rate	Range: 7.09% to 10.40%[333] Median: 8.65% Sustainable Growth Rate Model: 7.02% median

Mr. Coyne applies both a constant growth and a multi-stage DCF model to the Canadian and US proxy groups he has developed. Mr. Coyne's selection of proxy groups has been discussed in Section 5.2.2. In preparing the DCF models for these proxy groups, Mr. Coyne notes the profiles of US proxy group of companies are more like FEI than the Canadian proxy companies but he has nonetheless given them equal weight because of the importance of providing a Canadian perspective. Growth rates for both Canadian and US proxy groups were developed using data from a number of sources as noted in Table 5.5 above. The first five year's growth estimates were based on an average of analyst's estimates. This was followed by a five year transitional stage designed to change the growth rate each year on a *pro rata* basis and eventually connect with the long-term forecast for Year 11 and beyond. Growth estimates for Year 11 and beyond are based on the long-term forecast of GDP.[334]

Mr. Coyne has relied only on the multi-stage model to inform his recommendations for ROE noting that in the 2013 GCOC Decision, the Commission found the "use of analyst's forecasts is more consistent with the multi stage models where analysts forecasts can inform the early stage and longer term forecasts such as GDP growth, can inform the later stages." As outlined in Table 5.5, which took out flotation for comparability across estimates by the experts, the use of the multi-stage model produced results of 9.32 percent for Canada and 8.39 percent for the US proxy group.

According to Dr. Booth, the DCF model should only be used for low risk dividend paying stocks or the market as a whole, where the expected dividends can be assumed to grow at some long run average growth rate.[335]

Dr. Booth indicates he has placed little emphasis on the DCF model in the past and has traditionally viewed his DCF estimates as "checks" on his CAPM estimates but recent low Canada bond yields have given him cause for re-evaluation. Dr. Booth has relied on a DCF model using sustainable growth rates. The sustainable growth styled model is built on the premise that a company's growth is driven by a firm's expected earnings and the extent to which these earnings are paid out as dividends or retained for future investment in the company. Dr. Booth has applied his model to the market as a whole and estimates "the fair return as being 8.50-9.00% in Canada and slightly higher in the US." Dr. Booth estimates the US equity return in the 9.0 to 10 percent range. When DCF is applied individually against a proxy sample of eight US utilities (six were in Mr. Coyne's proxy group), an equity cost of 8.65 percent results based on median analyst five-year growth forecasts. However, when based on Dr. Booth's sustainable growth forecast approach, 7.02 percent is the median DCF equity forecast for the eight utilities in his proxy group.[336] Dr. Booth did not comment on the inclusion of flotation costs in his DCF estimates.

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[332] Exhibit C7-7-2, Direct Testimony of Dr. Booth, Appendix D, pp. 13–14.
[333] Forecast growth rate 4% to 7%; Current dividend yield range from 2.29% to 4.02%. Average: 3.21% and median: 3.2%; Current (November 18, 2015) dividend yield: 1.98%.
[334] Exhibit B-1, Appendix B, pp. 5–6, 58–59.
[335] Exhibit C7-7-2, pp. 50–51, 58; Appendix D, pp. 6–17.
[336] Exhibit C7-7-2, Appendix D, pp. 6–17; Ibid., pp. 50–51, 58.

Mr. Coyne does not agree that the sustainable growth rate approach as applied by Dr. Booth appropriately captures the expected growth rate of a regulated utility. In his words, "In the fullest form of the sustainable growth formula, new equity issuance, or what are commonly known as externally generated funds are also considered."[337] This method is the common approach for sustainable growth rate calculation and Dr. Booth's approach is the model in its simplest form projecting growth as a function of internally generated funds. Mr. Coyne's position is that a firm's growth is understated in this model by the failure to consider debt and equity issuances as a source of future growth.

Mr. Coyne also points out that the Federal Energy Regulatory Commission (FERC) has moved away from using the sustainable growth rates in its DCF methodology and now uses a two-step DCF methodology relying on a combination of analyst growth rates and GDP growth estimates. Dr. Coyne continues by stating he has concerns with the reasonableness of Dr. Booth's sustainable growth rate calculation in that he "has effectively pre-supposed analyst ROE and payout projections for his proxy group companies. Thus, by using this growth measure, Dr. Booth has assumed the reasonableness of analyst's ROE projections, yet, not the analyst's projections of growth rates by the same analysts." By example, he refers to the table on page 13 of Appendix D of Dr. Booth's evidence where the mean and median ROE projections for the proxy group are close to 10.2 percent but Dr. Booth's use of the simple form of the sustainable growth rate method yields ROEs of 6.83 and 7.02, respectively.[338]

In FEI's view, Dr. Booth's sustainable growth DCF approach guaranteed that future utility growth and resulting DCF value would be understated. FEI considers Dr. Booth's simplified sustainable growth model to be unrealistic as the only source of utility growth is the reinvestment of retained earnings and does not take into account funds generated by utilities through the injection of new equity (shown as the product of "s x v" where "s" represents the growth in shares outstanding and "v" is that portion of the market to book ratio that exceeds one). FEI points out that in the full form of the sustainable growth DCF model, the injection of new equity is accounted for and further, Dr. Booth has admitted he has included adjustments for the impact of external financing in his sustainable growth DCF models in the past.[339]

FEI submits Dr. Booth has suggested "the total impact of including the incremental source of financing would be negligible, assuming (a) that utility's market-to-book value is close to one, and (b) the growth in shares outstanding is very small." FEI points out that the eight US utilities he used to calculate his CAPM estimates and his sustainable growth DCF model have market to book ratios that are significantly higher than one and based on Dr. Booth's logic, would provide a higher than the presented DCF result.[340]

Intervener submissions

With reference to Dr. Booth's use of the sustainable growth model, AMPC/BCOAPO assert FEI only partially responded to the points he made during his cross-examination as to why the "s x v" effect is negligible. Concerning FEI's argument that the "s x v" term should be included, "Dr. Booth explained that in any event utility market-to-book ratios ought to be close to one, as regulation should lead to a market price that is approximately equal to the utility's book value, and the term furthermore contains a 'huge' risk of estimation

[337] Exhibit B-16, Rebuttal Testimony of Mr. Coyne, p. 36.
[338] Exhibit B-16, pp. 35–37.
[339] FEI Final Submission, pp. 89–90; T3:501.
[340] FEI Final Submission, p. 90; T3:625–626.

error." AMPC continue by referring to Dr. Booth's point that when the issuance of capital stock is negligible, the "s x v" is effectively zero and FEI has provided no evidence that it will dilute its capital stock by a non-negligible amount and Dr. Booth described why this was highly unlikely during the oral hearing.[341]

AMPC/BCOAPO assert that Mr. Coyne has relied on constant growth calculations and even though he ultimately claims not to have used them, they play a prominent role in his evidence. It is their position that constant growth DCF models are meaningless and have no place in the comparison, particularly where there are predictions of constant growth that exceed the growth of GDP.[342]

CEC submits the estimates from the constant growth model are likely inaccurate and highly inflated and recommends the Commission disregard or place very little weight on Mr. Coyne's constant growth DCF model and "disregard the comparison and the average that Mr. Coyne provides." It is CEC's position that Dr. Booth's evidence is superior to Mr. Coyne's and Dr. Booth's evidence is better used as a check than as a basis for ROE determination. Specifically, CEC states that Dr. Booth's evidence concerning sustainable growth rates "is reasonable and does not unduly understate the firm's growth model, and is superior to Mr. Coyne's analyst forecasts."[343]

FEI reply submission

FEI considers the evidence contradicts Dr. Booth's assumption that price to book ratios equal one pointing out the market to book ratios of the utilities used in Mr. Coyne's proxy groups averaged well over 2.0 and Dr. Booth's estimates based on sustainable growth rates have understated his DCF outcomes. FEI takes issue with Dr. Booth's view that it is unlikely that FEI "will dilute its capital stock by a non-negligible amount" pointing out FEI does not issue equity and Dr. Booth has "overlooked the fact that the S*V term is derived from the proxy group companies." Thus, based on these proxy groups, FEI asserts the results coming from Dr. Booth's simplified model could be significantly understated.[344]

5.2.4.2 Analyst estimates

The Brattle Group Report states the choice of an appropriate growth rate is the most controversial element of using DCF and note most economists are in agreement that investment analyst's expected growth rates are more representative of investor expectations than historical growth rates. The Brattle Group Report acknowledges some critics claim analyst's earnings growth rates are tainted by a bias towards optimism as there is an observed tendency for analysts to estimate growth rates that are higher than what actually occurs. However, the Brattle Group Report also makes the following statement:

> Analyst forecasts for the utility industry are likely to be more accurate than forecasts for other industries because firms with less variability in their earnings tend to have more accurate forecasts. This suggests analyst forecasts for the utility industry are likely to be more accurate and less prone to potential bias when compared to forecasts of other industries.[345]

[341] AMPC/BCOAPO Final Submission, p. 56; T3:601.
[342] AMPC/BCOAPO Final Submission, p. 58.
[343] CEC Final Submission, pp. 19, 41.
[344] FEI Reply Submission, p. 76.
[345] Exhibit A2-3, Brattle Group Report, p. 29.

Mr. Coyne submits that in the US, several regulatory changes have been implemented to deal with this issue. Specifically, both the US Securities and Exchange Commission and the New York Stock Exchange have taken measures designed to provide fair disclosure and remove the incentive for analysts' bias. In Canada, regulators took similar actions to improve the independence of research and ensure Canadian Securities Analysts practiced professionally. Mr. Coyne also noted the 2013 GCOC Decision rejected suggestions of analyst bias.[346]

One of Dr. Booth's arguments for relying upon unadjusted DCF results was his view that optimism bias exists in analyst's growth forecasts. Dr. Booth has provided evidence in the form of a Globe and Mail article based on a study by a consulting firm, McKinsey, reporting that analysts start out optimistic when making a five-year forecast before "they hone in on the correct number" as they get more information. Dr. Booth also reports that a 2007 study by Easton and Sommers documented the optimism bias at 2.84 percent when analyst's estimates are compared to current earnings realizations.[347]

FEI argues there is no evidence of analyst bias in growth forecasts relying upon the following reasons:

- The Brattle Group Report comments concerning the accuracy of forecasts in the utility industry and Dr. Booth's admission in the 2013 GCOC Decision that optimism bias in the utility industry is less evident than in other sectors in the economy.
- The Battle Group Report noted there is "substantial academic evidence that analyst earnings estimates are superior to other forecasts."
- Mr. Coyne identifies several factors explaining why the substantial academic evidence referred to in the Brattle Group Report is reasonable. Included among these are the facts that equity analysts have no incentive to provide optimistic research reports and are industry experts on the companies they follow as well as the regulatory changes that have been made on both sides of the Canada/US border.
- The Commission has rejected Dr. Booth's assertion that upward bias in growth forecasts requires adjustments to DCF results in each of the last three cost of capital proceedings.

FEI also points out that Mr. Coyne's multi-stage DCF limits the use of analyst growth rates to five years with a transition period following.[348]

<u>Intervener submissions</u>

AMPC/BCOAPO submit the potential for upward bias has inflated FEI's DCF estimates to an amount that would not be consistent with a fair return. They consider it problematic to rely on analyst's growth forecasts due to a well-known optimism bias attached to analyst forecasts. In addition to the evidence brought forward by Dr. Booth, AMPC/BCOAPO states this bias is confirmed by the current record "where comparisons to the capital market reports by TD, Aon Hewitt and Mercer show comparable or lower forecast returns for the market as a whole, than for Mr. Coyne's analyst forecasts for low risk utilities." AMPC/BCOAPO refer to a 2011 Alberta Utility Commission decision expressing concern for the potential for upward bias in analyst's growth estimates as further support for its position.

CEC submits the evidence supporting bias toward over-optimism when estimating earnings should be given significant weight. It is CEC's view that Mr. Coyne's use of analyst's growth rates in his multi-stage DCF model

[346] Exhibit B-1, Appendix B, pp. 55–56.
[347] Exhibit C7-7-2, Appendix D, pp. 14–15.
[348] FEI Final Submission, pp. 86–88.

may have inflated the evidence resulting in an ROE recommendation which is too high and therefore should be viewed with caution and adjusted downward. CEC did not share with the Commission how it reached this conclusion.

CEC holds that Dr. Booth's model is both reasonable and superior to Mr. Coyne's analyst forecasts and does not unduly understate the firm's growth model. CEC recommends the Commission heavily weigh the DCF estimate of Dr. Booth.[349]

FEI reply submission

FEI takes issue with the AMPC/BCOAPO suggestion that TD, Aon and Hewitt and Mercer capital market reports show comparable or lower forecast returns for the whole market than Mr. Coyne's analyst forecasts for low risk utilities. FEI asserts there is no evidence suggesting that a specific utility's earnings growth rates and the multi-stage DCF over a specific period of time should always be lower than market returns as a whole.

FEI does not support the use of pension plan information but states that if it were used, it would show that Mr. Coyne's multi-stage DCF results are close to the pension report's corresponding returns as cited by AMPC/BCOAPO. FEI points to the category within the Fearless Forecast and the Aon Hewitt report called US defensive equity. Mr. Coyne describes these as low-risk companies such as utilities. He outlines how when the arithmetic growth rate and an equity beta of .75 as relied upon in these reports are used, a geometric equivalent ROE of 8.5 percent is achieved. When an additional 50 basis points is added for flotation, he notes this would increase the ROE to 9.0 percent.[350]

AMPC/BCOAPO sur-reply

On May 16, 2016, AMPC/BCOAPO filed a sur-reply, which among other things took issue with FEI arguing the nature of pension forecasting for the first time in its reply submission. After submissions from the parties and a reply from AMPC/BCOAPO, the Commission allowed the sur-reply to remain on the record.

AMPC/BCOAPO submit that while it "recognizes that paragraph 144 (not 143, as FEI states) repeats some of the BCUC 1.40.2 response absent citation, the pension fund argument in FEI's Reply submission (pp. 60-64) remains largely general." AMPC/BCOAPO submit it did not argue that "pension returns" are relevant. It did argue that "published pension plan forecasts of general returns (asset classes like Canadian equities, US equities, etc.) are relevant to the returns potential investors might expect from FEI."[351]

Commission determination

There were three areas the Panel identified as needing to be explored in reaching its determination on the DCF model and its weighting in this proceeding: the choice of DCF approaches, guidance to be taken from expert witness submissions and the weight placed on analyst estimates.

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[349] CEC Final Submission, pp. 18, 41.
[350] FEI Reply Submission, pp. 73–74.
[351] AMPC/BCOAPO Sur-Reply, pp. 2–3.

a) Constant growth versus the multi-stage approach to using the DCF model

The primary issue with the use of these two models is whether it is appropriate to rely on a growth forecast in perpetuity as implied by the constant growth model or whether the growth forecast should be staged over a period of time settling into a tempered long-term perpetual grow rate thereafter. Dr. Booth favours the constant growth model but only in the context of the market as a whole stating that this and S&P utility indexes "are more reliable than for individual companies due to significant measurement error attached to forecasting future growth rates." Dr. Booth further notes it is impossible for utilities to grow faster than the GDP forever, thereby explaining a significant drawback to a constant growth DCF model when used in the context of a company or small group of companies. Mr. Coyne has prepared both constant growth and multi-stage DCF models but he relies only on the multi-stage model explaining that in the 2013 GCOC Decision, the Commission favoured a multi-stage approach.

The Panel considers the constant growth DCF model to have limited value when applied against a single company or small group of companies and agrees errors in forecasting will likely result due to the improbability of utilities perpetually growing at a rate faster than GDP. The Panel also agrees that if the constant growth model is to have any application, it is when taken in the context of the market as a whole thereby eliminating some of the issues related to determining a reasonable growth rate for a smaller group. **The Panel therefore finds that no weight can be placed on Mr. Coyne's constant growth DCF results as applied to his proxy groups.** For proxy group DCF estimates, the Panel favours use of the multi-stage DCF approach as it provides a more realistic and reasonable approach to estimating growth over the long-term.

b) Mr. Coyne and Dr. Booth's use of the DCF model

Dr. Booth has provided ranges for the overall equity return in the Canadian market of 8.50 percent and 9.5 percent and 9.0 to 10.0 percent in the US market as a whole. As Dr. Booth provided no definitive estimates for utilities as a group, the Panel infers that Dr. Booth intended these estimates to cover the upper end of his DCF estimate range. The fact that utilities are generally considered to be lower risk than the market as a whole would indicate a ROE estimate for utilities or FEI falling somewhere below these levels. However, this is only conjecture and as a result, the Panel places little weight on Dr. Booth's constant growth whole market DCF estimates for the purpose of determining a fair ROE.

Dr. Booth also introduced a version of the sustainable growth rate DCF approach asserting that a median ROE of 7.02 percent results when applied against his US proxy group of eight utilities. Dr. Booth did not provide evidence as to the level of adoption of this approach in Canada and the US although Mr. Coyne pointed out that FERC has moved away from any reliance on sustainable growth rates, a point the Panel notes was not contested. The Panel observes that Dr. Booth took into account only internally generated funds and neglected to take into account externally generated funds such as the issuance of new equity. This concern was raised by Mr. Coyne and AMPC/BCOAPO responded to this by stating Dr. Booth's explanation is FEI has provided no evidence it will dilute its capital stock by an amount that is non negligible and thus the s x v is effectively zero. While FEI does not issue equity to the public, the Panel notes FEI's equity financing requirements of $594 million related to expected capital expenditures in 2016-2018 (see Table 4.4) will likely require the shareholder to make equity injections to maintain FEI's approved equity structure. In addition, , Dr. Booth's sustainable growth model is applied to his proxy group, not FEI, and therefore whether FEI is to issue new equity is irrelevant given they were not part of the proxy group. The Panel is of the view that the lack of consideration of the potential for proxy companies to issue equity is important and could have resulted in a different set of outcomes. **Therefore, the Panel finds that no weight can be placed on Dr. Booth's sustainable growth rate model for his US proxy group as it is not based on a more robust and comprehensive version of this model.** Moreover, the Panel remains unpersuaded as to whether it is valid to apply the sustained growth rate model itself. There has been limited evidence in this proceeding on the model, its variations and the level of adoption in other jurisdictions. Given these limitations, the Panel views any results attributed to the use of this model with caution.

The Panel notes that Mr. Coyne, while preparing a constant growth DCF model, did not rely on it in his DCF calculations and therefore disagrees with AMPC that this information played a prominent role in his evidence. Instead, Mr. Coyne has relied upon his multi-staged DCF model results for his Canadian and US proxy groups. When commenting on the Canadian proxy group, Mr. Coyne stated he did not think it was anywhere near as good a comparator as his US sample and explains he uses them "because I find it helpful to use a Canadian sample to see what numbers I would derive, but I use them with caution."[352] The Panel agrees noting that in terms of form and function the companies in the US proxy group are closer than the companies Mr. Coyne has selected in his Canadian proxy group. The Panel has provided its assessment of Mr. Coyne's US proxy group data in Section 5.2.2 where it outlined a number of issues related to comparability with FEI and concluded US proxy data "is an imperfect reflection of the circumstances facing FEI requiring considerable judgement as to the weight to be placed on this data."

Given these concerns, the Panel finds that only limited weight can be placed on the DCF estimates based on either the Canadian or the US proxy groups. By Mr. Coyne's acknowledgement, the US proxy group is more comparable to FEI in terms of form and function when compared to the Canadian proxy group. Moreover, in the view of the Panel, the US proxy group companies operate in a different regulatory environment and likely face a greater level of risk than indicated by Mr. Coyne.

c) Analyst's Estimates

In the 2013 GCOC Decision, the Commission found that there was "reason to be cautious of potential bias in the utility sector." However, based the evidence presented by the experts, it was not convinced an adjustment for analyst bias should be made.[353] The Panel holds a similar view in this proceeding. Dr. Booth has provided evidence that support the existence of optimism bias. However, counter to this, the Brattle Group Report states utility industry estimates are likely to be more accurate than those in other industries. Moreover, as argued by FEI, Dr. Booth acknowledges this in the 2012 GCOC proceeding where he stated "optimism bias is probably more evidence (sic) in growth stocks than it is in value stocks, and it's less evident in utilities than in other areas."[354] **Given these considerations, the Panel finds that caution must be exercised with analyst estimates due to the potential for optimism bias but is not persuaded the evidence supports the need to adjust analyst forecasts related to the utility industry.**

[352] Oral Hearing Transcript Volume 2, p. 422.
[353] 2013 GCOC Decision, p. 71.
[354] 2012 GCOC proceeding, Exhibit B-26, p. 21.

5.2.4.3 Appropriate DCF estimate

Commission determination

As noted above, the Panel found that only limited weight could be given to Dr. Coyne's multi-stage DCF estimates, excluding the financing flexibility adjustment, of 9.32 for the Canadian and 8.39 percent for the US proxy groups but has a higher level of confidence in the US estimates due to them being a closer comparator to FEI on many parameters. However, also noted is the Panel's concern there is a greater level of risk faced by FEI's US comparators due to operating in a different regulatory environment which is not directly comparable to British Columbia. Given these factors, the Panel does not consider direct application of Mr. Coyne's estimates for either market to be appropriate. **Accordingly, with application of appropriate judgement, the Panel accepts a maximum 8.4 percent excluding the financing flexibility adjustment as the DCF estimate for an appropriate ROE.**

5.2.5 Financing flexibility adjustment

In the 2013 GCOC Decision, the Commission accepted an allowance for financial flexibility of 50 bps added to the CAPM and DCF tests in determining the fair ROE.[355] The decision referenced a definition of this allowance for financing flexibility as consisting of: (1) flotation costs comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle.[356]

Both Mr. Coyne and Dr. Booth agree that 50 bps is a reasonable financing flexibility adjustment[357] and Mr. Coyne is of the view an adjustment of 50 bps is common regulatory practice in Canada.[358]

FEI submits that 50 bps for financing flexibility is consistent with past precedent and expert evidence, that it is a reasonable financing flexibility adjustment, is common regulatory practice in Canada and addresses the utility's need to raise capital without impairing its financial integrity.[359]

CEC submits 50 bps is reasonable.[360]

Commission determination

The Panel notes there is agreement among the experts and parties to a 50 bps financing flexibility adjustment. This is consistent with the 2013 GCOC Decision and given the agreement of the parties, the Panel accepts an allowance for financial flexibility of 50 bps added to the CAPM and DCF tests in determining the fair ROE.

There was not an extensive examination of this issue in the current proceeding and as a result, no evidence to suggest deviating from using the 50 bps financing flexibility adjustment relied upon in recent hearings. However, with respect to Mr. Coyne's testimony that 50 bps is generally used in Canada, the Panel notes that there was no

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355 2013 GCOC Decision, p. 80.
356 2013 GCOC Decision, p. 79.
357 Exhibit B-1, Appendix B, p. 60.
358 Exhibit B-9, BCUC IR 39.1.
359 FEI Final Submission, pp. 99–100.
360 CEC Final Submission, p. 14.

evidence comparing Canadian jurisdictions on the record to support this. In addition, the Panel notes the Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. 2006 ROE Decision, the Commission allowed a "pure" flotation allowance of 25 bps for the DCF test and no flotation cost allowance for the CAPM and stated the Commission "will not automatically add a 50 basis point surcharge to whatever return it deems appropriate, but will exercise its judgment each time."[361] The Panel expects the issue to be more closely examined with a jurisdictional review on the application of a financing flexibility adjustment in Canada in FEI's next hearing dealing with ROE and common equity component.

5.2.5.1 FEI's ROE relative to other Canadian utilities

Mr. Coyne's comparison of the Canadian peer group companies' approved equity ratio and ROE in relation to his overall risk ranking is included in Table 5.6:

Table 5.6: Canadian Peer Group Comparative Risk Analysis and Authorized ROE[362]

Operating Company	Risk assessment relative to FEI	Authorized equity ratio	Authorized return on equity
Proposed FortisBC Energy Inc.	**N. A.**	**40.0%**	**9.50%**
Current FortisBC Energy Inc.	**N. A.**	**38.5%**	**8.75%**
ATCO Gas	**Less risky**	**38.0%**	**8.30%**
Enbridge Gas Distribution Inc.	**Less risky**	**36.0%**	**9.30%**
Union Gas	**Less risky**	**36.0%**	**8.93%**
Gaz Métro	**More risky**	**38.5%**	**8.90%**

Panel discussion

Although none of the parties presented arguments on the comparison of FEI's current or proposed ROE to other Canadian utilities and while not determinative of a fair ROE, the Panel considers this step useful for considering the overall reasonableness of the range of estimates presented in the CAPM and DCF estimates. When compared against FEI's current and proposed ROE to the Canadian peer group's ROEs and equity components compiles by Mr. Coyne, the Panel notes the experts' assessment that FEI is more risky than EGDI, Union Gas and ATCO Gas and less risky than Gaz Métro. Given this ranking, one would expect it is appropriate for FEI's ROE to fall somewhere above EGDI, Union Gas and ATCO Gas and below Gaz Métro. Given that ATCO Gas' ROE is less risky than FEI it is reasonable that ATCO Gas' authorized ROE is lower than that of FEI. With consideration of the inclusion of Gaz Métro's preferred shares in its capital structure and its higher allowed ROE, the Panel is satisfied FEI's current ROE is appropriately positioned relative to the riskier Gaz Métro. The Panel notes that Union Gas

[361] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism (2006 TGI ROE), Decision dated March 2, 2006, pp. 54–55.
[362] Exhibit B-1, Appendix B, p. 101.

and EGDI both have slightly higher authorized ROEs than FEI. However, this is offset by their significantly lower 36 percent equity ratio.

5.3 Appropriate return on equity

Commission determination

The Panel has determined that a return on equity of 8.75 percent meets the Fair Return Standard and is appropriate for FEI, effective January 1, 2016. This represents no change from the 2013 GCOC Decision where the Commission determined the same return on equity.

The Panel notes in the 2013 GCOC Decision, the Commission determined that the most compelling frameworks for assessing the return on equity are the DCF model and the CAPM and placed equal weight on the CAPM and DCF model in determining the allowed ROE.

The experts' DCF models and CAPMs and underlying assumptions have been explored extensively in this proceeding. The Panel notes Mr. Coyne arrives at his recommendation of 9.5 percent ROE based on his detailed analysis, placing equal weight on the estimates produced by his models. On the other hand, Dr. Booth recommends an ROE of 7.5 percent more from an application of his judgment than from any output from his models.

With respect to reliance on the models, the Panel agrees with Mr. Coyne, that the use of the models provides different perspective that helps inform the estimate of ROE but that both the DCF model and CAPM have their own set of inherent limitations. All parties advise the Panel to use its judgment to assess the reasonableness of the results of the models. FEI underlines the importance of using multiple tests to be assured of a reasonable estimate of ROE and AMPC/BCOAPO recommend using the models as a check on each other and applying judgement based on external conditions.

In determining the appropriate weight to place on the models, the Panel recognizes they are imperfect and must consider the totality of the evidence. In Mr. Coyne's approach, both models rely on proxy group information and a selection of proxy companies that are imperfect comparators due to differing business and regulatory environments than FEI. In the view of the Panel, company specific risk is not important in the CAPM. The CAPM depends on a number of subjective decisions including the determination of the risk free rate in the current all-time low interest rate environment. Both experts outline the issues with the CAPM in the current environment. The DCF model is highly sensitive to growth rate estimates and there can be significant variability in analyst estimates and adding to this, there are no strong comparator Canadian companies for use as proxies in the DCF model. As a result of the current global economic environment, the reliability of the models has been called into question more than once in the previous cost of capital hearings, requiring the Panel to exercise its judgement to a greater degree.

Accordingly, in addition to considering its findings on the appropriate ROE indicated by: (1) the CAPM model of approximately 8.5 percent including financing flexibility adjustment; and (2) the DCF model of no more that 8.9 percent including a financing flexibility adjustment, the Panel also considers whether conditions have changed sufficiently since the 2012 GCOC proceeding to warrant an increase or decrease in ROE.

In addition to favouring the application of judgment more heavily than in the previous decision, the Panel does not believe a strict reliance on an equal weighted mechanical calculation of its findings with respect to DCF model and CAPM outputs in this circumstance is appropriate for determining a fair ROE. Given these factors, the Panel has concluded FEI's currently allowed ROE of 8.75 percent, within the context of a 38.5 percent equity capital structure, remains well within the range of current model outputs and is therefore reasonable.

Taking these factors together and weighing them accordingly, the Panel considers there to be insufficient justification for awarding either a higher or lower ROE at this time. The Panel also examined and found there is no compelling evidence to support the need to increase the return on equity given the 38.5 percent common equity component.

As a check, the Panel notes FEI's 8.75 percent approved ROE, given its equity component of 38.5 percent falls into the appropriate range among its Canadian regulated utility comparators. While not determinative, this further supports the Panel's decision to leave FEI's ROE unchanged.

6.0 AUTOMATIC ADJUSTMENT MECHANISM

The issue the Panel must deal with is whether to continue with an AAM as a means of providing annual updates to the benchmark utility's ROE or whether it should be suspended or eliminated entirely.

An AAM based on changes to long-term Canada bond rates was first implemented by the Commission in 1994[363] but in 2009, by Order G-158-09, it was eliminated. In eliminating the AAM in 2009, the Commission stated, "in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the Fair Return Standard."[364] In the 2013 GCOC Decision, the AAM was reinstituted on the basis that it "better meets the FRS than giving no consideration to market changes over the period between ROE proceedings." The Commission in this instance addressed some of the concerns with previous mechanisms and established a two variable model taking into account utility bond spreads as well as long-term Canada Bond yields. However, in recognition of the effect of monetary policy on bond rates, the Commission directed any implementation of this mechanism be subject to an actual long-term Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula would not apply unless the long Canada bond yield was below 3.8 percent.[365] The Canada long-term bond yield has remained below the 3.8 percent threshold since 2013 and therefore, the AAM was not applied to FEI's ROE during the period since the 2013 GCOC Decision.[366]

FEI's position is that a formula cannot capture all of the changes affecting a utility's cost of capital and will yield a return that does not meet the Fair Return Standard. FEI submits the Commission should suspend use of the AAM formula in this jurisdiction and review the cost of capital in a three to five-year time frame. A periodic review is the best way to ensure the ROE is reflective of the true cost of equity and meets the Fair Return Standard. However, if the Commission was to continue to believe an AAM to be an appropriate approach, FEI

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[363] 2013 GCOC Decision, p. 81.
[364] Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure (2009 TGI ROE), Decision dated December 16, 2009.
[365] Ibid., pp. 90–91.
[366] Exhibit B-1, p. 32.

recommends a two-factor model capturing corporate credit conditions as well as the prevailing risk free bond rates as approved in the 2013 GCOC Decision.[367]

FEI notes that an AAM has been in place since 2013. Over this period, there has not been an ROE adjustment and over this period, Régie Quebec has suspended application of its formula. Further, FEI points out that Dr. Booth opines he doesn't expect it will be triggered in the next three years.[368]

Mr. Coyne in his Direct Testimony holds views that are consistent with those of FEI.[369] He also notes in his rebuttal testimony that using a formulaic AAM introduces the potential for error in setting ROE as there is risk that bond yields and credit spreads, the formulaic coefficients, do not effectively model utility returns. It is Mr. Coyne's opinion that use of an AAM formula is not a substitute for proceedings where cost of capital evidence is presented and vetted by the stakeholders and it should be only relied upon to make interim changes to the cost of capital between rate proceedings.[370]

Intervener submissions

AMPC/BCOAPO support continuation of the use of the AAM arguing there was substantial work done to arrive at this formula both in the 2012 GCOC proceeding and to a lesser extent this hearing and thereby reinforcing the benefit of an AAM for stakeholders. In their view, the efficiency benefits of the 2013 GCOC Decision approved AAM formula remains relevant and the fact the long Canada bond yield has yet to meet the 3.8 percent long Canada bond trigger does not invalidate its usefulness.[371]

Dr. Booth states that adjustment models allow the ROE to be kept current without a need for extensive hearings but notes that keying a "fair ROE off the long Canada bond forecast currently causes significant problems due to distortions in that forecast."[372] His current judgement is the fair ROE has not decreased to the same extend as has the long Canada bond yield pointing out they are set by "global policy makers" or central banks rather than investors. Consequently, he judges adjusting the ROE by 50 to 75 percent of the decrease in long Canada bond yields, as recommended in the 2012 GCOC proceeding, underestimates the fair ROE.

Dr. Booth still regards 3.8 percent as "a minimum long Canada bond yield consistent with investors trading off risk and return, since this equates to a negligible real after tax rate of return for a taxable investor." Further, he states that he is not as optimistic as RBC and other forecasters' expectations that the 3.8 percent rate will be reached in 2018, as it will depend on when the Federal Reserve Board begins to sell its stockpile of government debt. Dr. Booth states he is happy to set a fixed rate for the period ending in 2018 noting he does not think in the next three years the one-year ahead forecast long Canada bond yields will reach 3.80 percent.[373]

[367] Exhibit B-1, pp. 32–33; FEI Final Submission, p. 101.
[368] FEI Final Submission, pp. 101–102.
[369] Exhibit B-1, Appendix B, p. 103.
[370] Exhibit B-16, p. 10.
[371] AMPC/BCOAPO Final Submission, p. 69.
[372] Exhibit C7-7-1, p. 63.
[373] Exhibit C7-7-1, p. 63.

CEC recommends the Commission continue with the existing AAM pointing out that the Commission is likely to review the cost of capital regardless of whether an AAM is in place or not. CEC submits that the AAM can provide comfort that the ROE will be responsive to current situations.[374]

Commission determination

The Panel is not persuaded that continuing to rely on an AAM to update FEI's ROE on an annual basis is appropriate or will necessarily meet the Fair Return Standard. Therefore, the Panel suspends further use of an AAM as a mechanism to adjust FEI's ROE on an annual basis.

The Panel continues to hold the view that an effective AAM can be a useful tool in providing an updating mechanism for ROE thereby eliminating some of the need for lengthy and expensive formal reviews. However, the Panel acknowledges that economic conditions are uncertain and accept Dr. Booth's explanation of long Canada bond yields being less affected by investors and more by central banks. Therefore, the Panel does not believe that continuing with an AAM at this time will necessarily result in changes reflecting a fair ROE or meeting the Fair Return Standard.

Over the past three years, bond yields have not reached the 3.80 percent trigger point specified in the 2013 GCOC Decision nor is there conclusive evidence in this proceeding this target will be reached over the next few years. The Panel acknowledges that RBC and other rate forecasters have predicted that the trigger point will be exceeded by 2018. However, there were similar predictions at the time of the 2012 GCOC proceeding which did not occur and in this instance, Dr. Booth has expressed doubt as to the 3.80 percent trigger point being reached by the end of 2018.

In the Panel's view, there is limited benefit to continuing to apply the AAM for the next period of time and there may be potentially undesirable consequences with its continued use. In addition, there has been little examination of the formula itself and no further evidence to suggest a 3.80 percent trigger point is as valid today as it was considered to be in the 2013 GCOC Decision. Therefore, the Panel is persuaded that a suspension of the AAM is warranted. However, once there is a return to more certain economic conditions with more normal interest rates, the Panel believes the re-implementation of an AAM is worthy of further consideration.

7.0 FEI AS THE BENCKMARK UTILITY

In the 2013 GCOC Decision, the Commission found that FEI was the appropriate benchmark utility and stated:

> FEI is well established, of sufficient size and has a diverse customer and asset base. In addition, FEI is well understood as a utility by all the participants as it has traditionally been used as the benchmark utility in British Columbia. This and the fact that there is a substantial body of FEI related evidence already on the record in this proceeding makes FEI a reasonable candidate for the benchmark utility. Therefore, notwithstanding the various positions of the participants as to whether FEI can be described as a pure play gas distribution utility, the Commission Panel agrees with the participants and accepts FEI, in the present time frame, as the most appropriate choice for the benchmark utility.[375]

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[374] CEC Final Submission, p. 117.
[375] Order G-148-12, Reasons for Decision, p. 4.

FEI states the Commission should continue to treat FEI as the benchmark utility and based on its current characteristics there is no compelling reason to change.[376]

CEC agrees that FEI should continue as the benchmark utility and recommends that the Commission maintain this status.[377]

Commission determination

No party in this proceeding disagreed with FEI continuing to be the benchmark utility. Accordingly, the Panel directs **the common equity component and ROE approved in this decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.**

[376] Exhibit B-1, pp. 34–35.
[377] CEC Final Submission, p. 118.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of August 2016.

Original Signed By

K. A. KEILTY
PANEL CHAIR / COMMISSIONER

Original Signed By

D. A. COTE
COMMISSIONER

Original Signed By

N. E. MACMURCHY
COMMISSIONER

British Columbia Utilities Commission

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Vancouver, BC Canada V6Z 2N3
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ORDER NUMBER
G-129-16

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for its Common Equity Component and Return on Equity for 2016

BEFORE:
K. A. Keilty, Panel Chair/Commissioner
D. A. Cote, Commissioner
N. E. MacMurchy, Commissioner

on August 10, 2016

ORDER

WHEREAS:

A. On October 2, 2015, FortisBC Energy Inc. (FEI) filed an application for a review of its common equity component and return on equity for 2016 (Application) pursuant to the British Columbia Utilities Commission (Commission) decision in the Generic Cost of Capital Stage 1 proceeding;

B. In its Application, FEI submits that the amalgamated FEI (the amalgamation of three affiliated entities: the former FortisBC Energy Inc., FortisBC Energy [Whistler] Inc. and FortisBC Energy [Vancouver Island] Inc.) continues to be the logical choice to serve as the benchmark utility for the purpose of determining the cost of capital for other utilities;

C. By Order G-177-15 dated November 9, 2015, the Commission established a proceeding to review the Application. The regulatory review was by way of a limited scope oral hearing and included two rounds of information requests (IRs) to FEI and one round of IRs on intervener evidence;

D. Six parties registered as interveners in this proceeding. Among those registered, the most active were the Commercial Energy Consumers of British Columbia, the British Columbia Old Age Pensioners' Association *et al*. and the Association of Major Power Customers of BC (AMPC): collectively, the "Utility Customers";

E. On December 7, 2015, the Commission issued Order G-193-15 in the FEI Annual Review of 2016 Delivery Rates Decision setting interim delivery rates for all non-bypass customers effective January 1, 2016 and approving FEI's existing capital structure and return on equity on an interim basis effective January 1, 2016, pending the outcome of this cost of capital proceeding;

F. On December 15, 2015, the Commission issued Order G-204-15 and ordered, among other things, that FEI's existing common equity component and return on equity would remain the benchmark on an interim basis, effective January 1, 2016;

G. On January 26, 2016, the Utility Customers filed intervener evidence of their expert witness, Dr. Laurence Booth;

H. The oral hearing took place from March 9, 2016 to March 11, 2016;

I. The argument phase of the proceeding took place from April 3, 2016 to April 28, 2016. On May 5, 2016, AMPC sought leave to file two narrow sur-reply submissions;

J. By Order G-68-16 dated May 13, 2016, the Commission, after considering comments from FEI and other interveners, allowed the sur-reply to remain on record; and

K. The Commission has reviewed and considered all of the evidence and submissions on record for the proceeding.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1. FortisBC Energy Inc.’s common equity component is set at 38.5 percent, effective January 1, 2016.

2. FortisBC Energy Inc.’s return on equity is set at 8.75 percent, effective January 1, 2016.

3. The use of the Automatic Adjustment Mechanism formula is suspended indefinitely.

4. The common equity component and return on equity approved for FortisBC Energy Inc. in the decision issued concurrently with this order will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.

5. The common equity component and return on equity will remain in effect until otherwise determined by the Commission.

6. FortisBC Energy Inc.’s interim rates set by Order G-193-15 are approved as permanent, effective January 1, 2016. FortisBC Energy Inc. is to file, within 15 working days from the date of this order, updated final rate schedules in accordance with Directives 1 and 2 of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of August 2016.

BY ORDER

Original Signed By:

K. A. Keilty
Commissioner

FortisBC Energy Inc.

Application for its Common Equity Component and Return on Equity for 2016

LIST OF ACRONYMS

2006 TGI ROE Decision	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, Decision dated March 2, 2006
2009 TGI ROE Decision	Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. Return on Equity and Capital Structure, Decision dated December 16, 2009
AAM	Automatic Adjustment Mechanism
AMPC	Association of Major Power Customers of BC
Application	FortisBC Energy Inc. Application for its Common Equity Component and Return on Equity for 2016
Atmos	Atmos Energy Corporation
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	British Columbia Municipal Electrical Utilities
BCOAPO	British Columbia Old Age Pensioners' Organization *et al.*
BCUC, or Commission	British Columbia Utilities Commission
bps	basis points
CGA	Canadian Gas Association
CAPM	capital asset pricing model
CCAPM	conditional capital asset pricing model
CEC	Commercial Energy Consumers Association of British Columbia
Consensus Economics	Consensus Economics Inc.
COV	City of Vancouver
Creative Energy	Creative Energy Vancouver Platforms Inc.
DCF	discounted cash flow

EGDI	Enbridge Gas Distribution Inc.
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FortisBC	FortisBC Utilities
GCOC	Generic Cost of Capital
GHG	greenhouse gas
ICG	Industrial Customers Group
ICR	interest coverage ratio
IR	Information Request(s)
LNG	liquefied natural gas
MRP	market risk premium
Moody's	Moody's Investor Services
NGTL	Nova Gas Transmission Ltd.
OEB	Ontario Energy Board
PBR	Performance Based Rate-making
PMM	purchase money mortgage(s)
RBC	Royal Bank of Canada
ROE	return on equity
UCA	*Utilities Commission Act*
Utility Customers	Commercial Energy Consumers Association of British Columbia, British Columbia Old Age Pensioners' Organization *et al.* and Association of Major Power Customers of BC

LIST OF APPEARANCES

P. Miller	Commission Counsel
L. Bussoli	Commission Counsel
M. Ghikas	Counsel for FortisBC Energy Inc.
T. Ahmed	Counsel for FortisBC Energy Inc.
R. B. Wallace, Q.C.	Counsel for Association of Major Power Customers of B.C.
C. Weafer	Counsel for Commercial Energy Consumers of British Columbia

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E. Cheng	Commission Staff
L. Cheung	Commission Staff
S. Allen	Consulting Staff
Allwest Reporting Ltd.	Court Reporters

LIST OF PANELS

FORTISBC ENERGY INC.

Expert Opinion on a Benchmark Fair Return

James M. Coyne	Concentric Advisors

ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC, COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA AND BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION *ET AL.*, COLLECTIVELY THE UTILITY CUSTOMERS

Laurence D. Booth, DBA	University of Toronto

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for Common Equity Component
and Return on Equity for2016

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated October 15, 2015 - Appointing the Commission Panel for the review of the FortisBC Energy Inc. Application for Common Equity Component and Return on Equity for2016
A-2	Letter dated November 9, 2015 – Commission Order G-177-15 establishing the Regulatory Timetable
A-3	Letter dated November 25, 2015 – Commission Information Request No. 1 to FEI
A-4	**CONFIDENTIAL** Letter dated November 25, 2015 – Confidential Commission Information Request No. 1 to FEI
A-5	Letter dated November 30, 2015 – Request for Submissions on Interim Order
A-6	Letter dated December 4, 2015 – Commission amending Regulatory Timetable
A-7	Letter dated December 15, 2015 – Commission Order G-204-15 with reasons for decision on interim rates
A-8	Letter dated January 12, 2016 – Commission Information Request No. 2 to FEI
A-9	Letter dated January 15, 2016 – BCUC Rules of Practice and Procedure to parties
A-10	Letter dated February 9, 2016 – Commission Intervener Evidence Information Request No. 1 to Utility Customers
A-11	Letter dated February 16, 2016 – Commission cancelling Procedural Conference and Request for written submissions
A-12	Letter dated February 25, 2016 – Commission clarifying Scope of Oral Hearing in response to FEI (Exhibit B-15)

A-13 Letter dated March 3, 2016 – Oral Hearing information

A-14 Letter dated May 6, 2016 – Request for Submissions on AMPC’s request to file sur-reply submissions

A-15 Letter dated May 13, 2016 – Commission Order G-68-16 with reasons for decision on AMPC’s request for leave to file sur-reply

COMMISSION STAFF DOCUMENTS

A2-1 Letter dated November 25, 2015 – Commission staff filing FortisBC Energy Inc. – Price Risk Management Workshop Summary Report (October 27, 2015)

A2-2 Letter dated January 12, 2016 – Commission staff filing Morningstar Australasia Pty Ltd. – Morningstar Stock Sector Structure (2011)

A2-3 Letter dated January 13, 2016 – Commission staff filing The Brattle Group – Survey of Cost of Capital Practices in Canada (May 31, 2012)

A2-4 Submitted at Oral Hearing March 10, 2016 - NEW JERSEY RESOURCES, INVESTOR FACT SHEET, DATED NOVEMBER 13, 2015

A2-5 Submitted at Oral Hearing March 10, 2016 - THREE-PAGE EXCERPT FROM STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES DECISION, "EXHIBIT P-1"

A2-6 Submitted at Oral Hearing March 10, 2016 - TWO-PAGE EXCERPT FROM STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES DECISION, RE: EVIDENCE OF PAUL R. MOUL

A2-7 Submitted at Oral Hearing March 10, 2016 - EXCERPTS FROM ATMOS ENERGY CORPORATION 2014 SUMMARY ANNUAL REPORT, "INVESTING FOR SAFETY"

A2-8 Submitted at Oral Hearing March 10, 2016 - DALLAS MORNING NEWS ARTICLE DATED AUGUST 19, 2013

A2-9 Submitted at Oral Hearing March 10, 2016 - EXCERPT FROM FORTISBC WEBSITE, "SWITCH TO NATURAL GAS AND SAVE"

A2-10 Submitted at Oral Hearing March 10, 2016 - EXCERPTS FROM WRITTEN EVIDENCE OF JAMES H. VANDER WEIDE

APPLICANT DOCUMENTS

B-1	**FORTISBC ENERGY INC. (FEI)** Letter Dated October 2, 2015 - Application for Common Equity Component and Return on Equity for2016
B-2	Letter dated December 4, 2015 - FEI Submission regarding Interim Order Exhibit A-5
B-3	Letter dated December 9, 2015 – FEI Reply Submission regarding Interim Order
B-4	Letter dated December 18, 2015 – FEI Response to CEC IR No. 1
B-5	Letter dated December 18, 2015 – FEI Response to BCOAPO IR No. 1
B-6	Letter dated December 18, 2015 – FEI Non-Confidential Response to BCUC Confidential IR No. 1
B-7	Letter dated December 18, 2015 – FEI Response to AMPC IR No. 1
B-8	Letter dated December 18, 2015 – FEI Response to AMPC Concentric IR No. 1
B-9	Letter dated December 18, 2015 – FEI Response to BCUC IR No. 1
B-10	Letter dated January 22, 2016 – FEI Response to BCUC IR No. 2
B-11	Letter dated January 22, 2016 – FEI Response to ICG IR No. 2
B-12	Letter dated January 22, 2016 – FEI Response to CEC IR No. 2
B-12-1	**CONFIDENTIAL** – Letter dated January 22, 2016 – FEI Confidential response to CEC IR-2_48.3.3
B-13	Letter dated February 9, 2015 – FEI Information Request on Intervener Evidence to AMPC
B-14	Letter dated February 18, 2015 – FEI Submission on Exhibit A-11 and Request for Clarification
B-15	Letter dated February 22, 2015 – FEI Reply Submission on Scope of Oral Evidence
B-16	Letter dated February 29, 2015 – FEI Submitting Rebuttal Evidence of FEI and Mr. Coyne
B-17	Letter dated March 4, 2016 - FEI Submitting Witness Panel Direct Testimony

B-18	Submitted at Oral Hearing March 9, 2016 - BAR GRAPH ENTITLED "FIGURE 1: RECOMMENDATION VS. ALLOWED FOR Canadian DISTRIBUTORS"
B-19	Submitted at Oral Hearing March 10, 2016 - CHAPTER 5 FROM THE IBBOTSON VALUATION HANDBOOK
B-20	Submitted at Oral Hearing March 10, 2016 - UNDERTAKING NO. 1, RE: TRANSCRIPT VOLUME 1, PAGE 141, LINE 21 TO PAGE 142, LINE 18
B-21	Submitted at Oral Hearing March 10, 2016 - UNDERTAKING NO. 2, RE: TRANSCRIPT VOLUME 1, PAGE 120, LINE 4 TO PAGE 121, LINE 20
B-22	Submitted at Oral Hearing March 10, 2016 - UNDERTAKING NO. 3, RE: TRANSCRIPT VOLUME 1, PAGE 65, LINES 18 TO 20
B-23	Submitted at Oral Hearing March 10, 2016 - UNDERTAKING NO. 4, RE: TRANSCRIPT VOLUME 1, PAGE 144, LINES 7 TO 17
B-24	Submitted at Oral Hearing March 11, 2016 - UNDERTAKING NO. 5, RE: TRANSCRIPT VOLUME 1, PAGE 144, LINE 23 TO PAGE 145, LINE 6
B-25	Submitted at Oral Hearing March 11, 2016 - UNDERTAKING NO. 6, RE: TRANSCRIPT VOLUME 1, PAGE 96, LINE 16 TO PAGE 97, LINE 4
B-26	Submitted at Oral Hearing March 11, 2016 - "DOCUMENTS FOR FEI CROSS-EXAMINATION OF DR. BOOTH"
B-26-1	Letter dated March 17, 2016 - FEI Submitting Revised Undertaking No.6
B-27	Submitted at Oral Hearing March 11, 2016 - MR. COYNE'S CO-AUTHORED EVIDENCE IN FRONT OF THE RÉGIE
B-28	Submitted at Oral Hearing March 11, 2016 - LIST OF COMPANIES WITH A TICKER AND AN M/B ON IT
B-29	Submitted at Oral Hearing March 11, 2016 - UNDERTAKING NO. 7, RE: TRANSCRIPT VOLUME 1, PAGE 135, LINE 3 TO PAGE 137, LINE 22
B-30	Submitted at Oral Hearing March 11, 2016 - UNDERTAKING NO. 8, RE: TRANSCRIPT VOLUME 2, PAGE 460, LINE 25 TO PAGE 461, LINE 9
B-31	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 9

B-32	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 10
B-33	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 11
B-34	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 12
B-35	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 13
B-36	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 14
B-37	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 15
B-38	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 16
B-39	Letter dated March 17, 2016 - FEI Submitting Undertaking No. 17

INTERVENER DOCUMENTS

C1-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter Dated November 10, 2015 – Request for Intervener Status by Christopher Weafer
C1-2	Letter Dated November 30, 2015 – CEC submitting IR No. 1
C1-3	Letter dated December 4, 2015 - CEC Submission regarding Interim Order Exhibit A-5
C1-4	Letter dated January 12, 2016 – CEC submitting IR No. 2 to FEI
C1-5	Letter dated February 19, 2015 – CEC Submission on Scope of Oral Evidence
C2-1	**UNION GAS LIMITED (UNION GAS)** Letter Dated November 16, 2015 – Request change to Interested Party from Intervener Status by Patrick McMahon - changed to Interested Party see D-1
C3-1	**BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU)** Letter Dated November 20, 2015 – Request for Intervener Status by Marg Craig and Alex Love
C3-2	Letter dated December 4, 2015 - BCMEU Submission regarding Interim Order Exhibit A-5

C4-1 **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO)** Letter Dated November 20, 2015 – Request for Intervener Status by Tom Loski

C5-1 **BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, DISABILITY ALLIANCE BC, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCOAPO)** Letter Dated November 23, 2015 – Request for Intervener Status by Tannis Braithwaite, Lobat Sadrehashemi and James Wightman

C5-2 Letter Dated November 30, 2015 – BCOAPO submitting IR No. 1

C5-3 Letter dated December 4, 2015 - BCOAPO Submission regarding Interim Order Exhibit A-5

C5-4 Letter dated January 12, 2016 – BCOAPO submitting Comments regarding IR No. 2

C5-5 Letter dated February 19, 2015 – BCOAPO Submission on Scope of Oral Evidence

C6-1 **INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter Dated November 23, 2015 – Request for Intervener Status by Brian Merwin and Robert Hobbs

C6-2 Letter dated December 4, 2015 - ICG Submission regarding Interim Order Exhibit A-5

C6-3 Letter dated January 12, 2016 – ICG submitting IR No. 2 to FEI

C7-1 **ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)** Letter Dated November 23, 2015 – Request for Intervener Status by Matthew Keen, Brian Wallace, and Richard Stout

C7-2 Letter Dated November 30, 2015 – AMPC submitting IR No. 1 to FEI

C7-3 Letter Dated November 30, 2015 – AMPC submitting IR No. 1 to Mr. Coyne (FEI)

C7-4 Letter Dated December 4, 2015 – AMPC Submission on interim order

C7-5 Letter Dated December 9, 2015 –AMPC Comments regarding Reply Submission on Interim Order

C7-6 Letter dated January 12, 2016 – AMPC submitting comments regarding IR No. 2

C7-7 Letter dated January 26, 2016 – AMPC submitting Evidence of Dr. Booth

C7-7-1 Letter dated February 3, 2016 – AMPC submitting Correction to Dr. Booth Evidence

C7-7-2 Letter dated March 4, 2016 – AMPC Submitting Clean Copy of Dr. Booth's Evidence

C7-8 Letter dated February 18, 2016 – AMPC submitting Dr. Booth Information Responses to FEI IR No. 1

C7-9 Letter dated February 18, 2016 – AMPC submitting Dr. Booth Information Responses to BCUC IR No. 1

C7-10 Letter dated February 19, 2015 – AMPC Submission on Scope of Oral Evidence

C7-11 Letter dated March 9, 2016 – AMPC submitting Booth Opening Statement

C7-12 Submitted at Oral Hearing March 9, 2016 - AMPC BOOK OF DOCUMENTS

C7-13 Submitted at Oral Hearing March 10, 2016 - FEI 2016 ROE AMPC WITNESS AID

INTERESTED PARTY DOCUMENTS

D-1 **UNION GAS LIMITED (UNION GAS)** Letter Dated November 16, 2015 – Request change to Interested Party from Intervener Status by Patrick McMahon

D-2 **CORIX MULTI-UTILITY SERVICES INC. (CORIX)** Letter Dated November 18, 2015 – Request for Interested Party Status by Ian Wigington

D-2-1 Letter Dated December 4, 2015 – Corix Submission on interim order

D-3 **PACIFIC NORTHERN GAS LTD. (PNG)** Letter Dated November 23, 2015 – Request for Interested Party Status by Janet Kennedy, Verlon Otto and Anwar Chaudry

D-3-1 **PACIFIC NORTHERN GAS LTD.** Letter dated December 3, 2015 - Submission regarding Interim Order Exhibit A-5

D-4 **CREATIVE ENERGY (CE)** Letter Dated November 23, 2015 – Request for Interested Party Status by Michelle McLarty

D-5 **SENTINEL ENERGY MANAGEMENT INC. (SENTINEL)** Letter Dated December 7, 2015 – Request for Late Interested Party Status by Jim Langley

LETTERS OF COMMENT

E-1 **RIVER DISTRICT ENERGY** Letter dated December 1, 2015 - Submission regarding Interim Order Exhibit A-5

E-2 **FORTISBC ALTERNATIVE ENERGY SERVICES INC. (FAES)** Letter dated December 3, 2015 - Submission regarding Interim Order Exhibit A-5

E-3 **FORTISBC INC. (FBC)** Letter dated December 3, 2015 - Submission regarding Interim Order Exhibit A-5

E-3-1 Letter Dated December 9, 2015 – FBC Reply Submission regarding Interim Order

2018 Alberta Utilities Commission Generic Cost of Capital

AUC
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

August 2, 2018

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Alberta Utilities Commission
Calgary, Alberta

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.

---

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:

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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]

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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

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

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

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]
>
> …
>
> 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

[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]

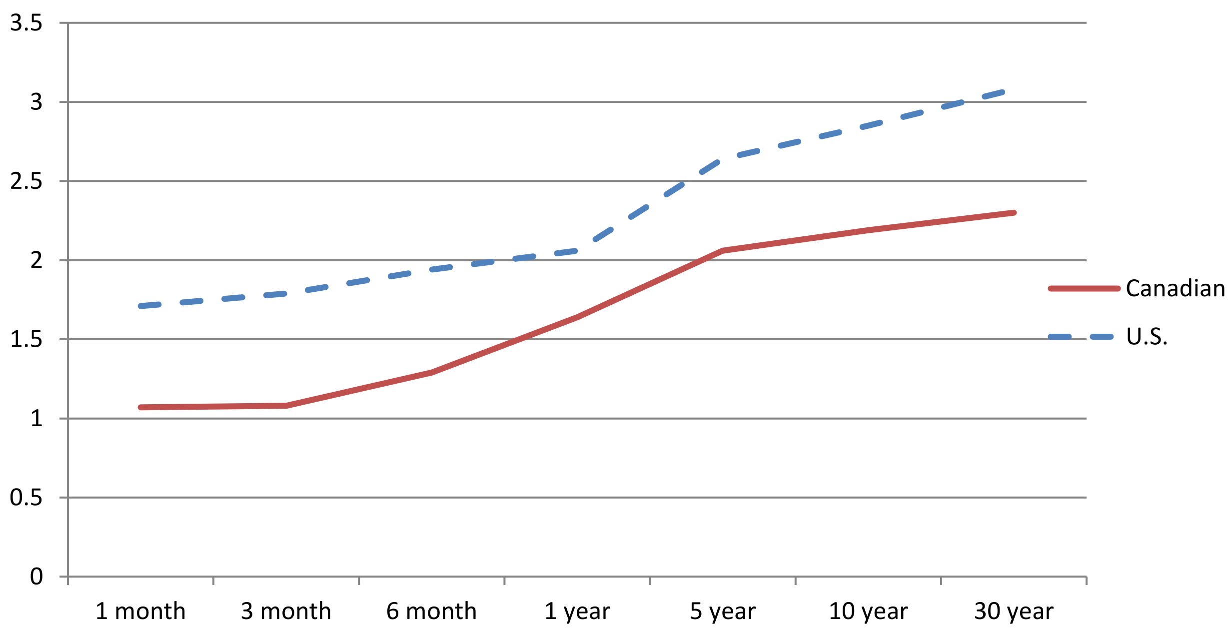
154. Mr. Buttke and Mr. Hevert provided similar evidence pointing to rising inflation since 2016, and a broad expectation that inflation will continue to rise modestly toward two per cent in the U.S. and Canada. In contrast, Mr. Thygesen argued that inflation is low and falling.[186]

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]

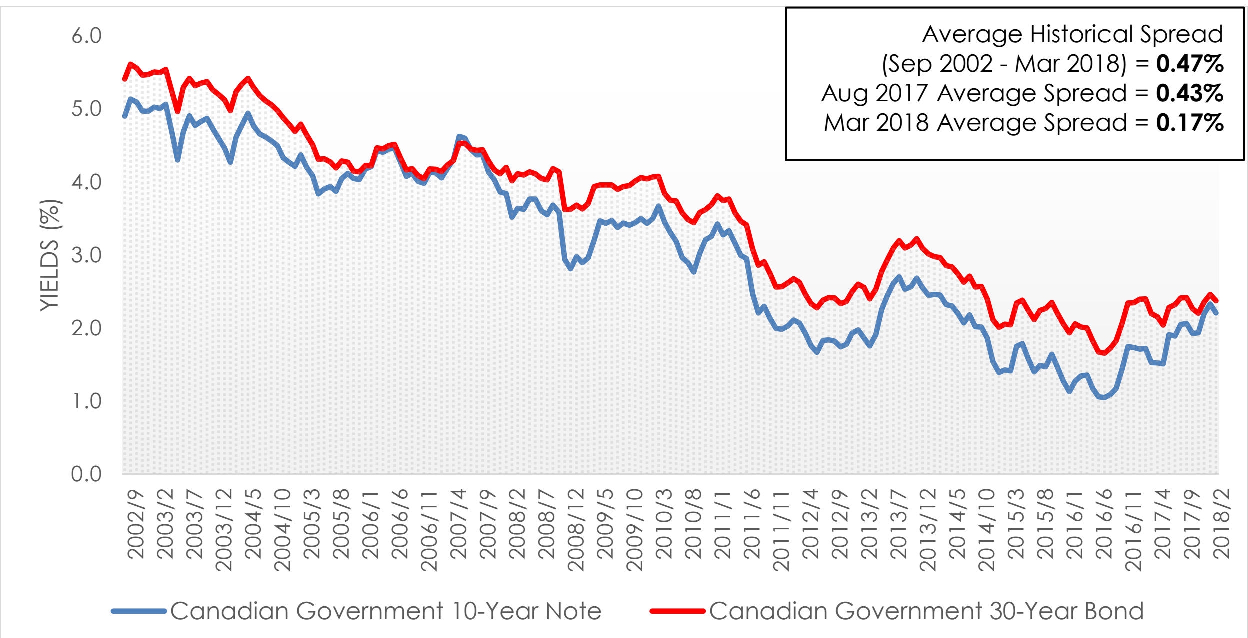


185 Exhibit 22570-X0562.01, PDF page 20.
186 Exhibit 22570-X0551, PDF page 37.
187 Decision 20622-D01-2016, paragraph 50.
188 Exhibit 22570-X0153.01, PDF page 28 indicates increases on these dates: December 14, 2016, March 15, 2017, and June 14, 2017. Exhibit 22570-X0767.01, PDF page 29 indicates an 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.

[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]

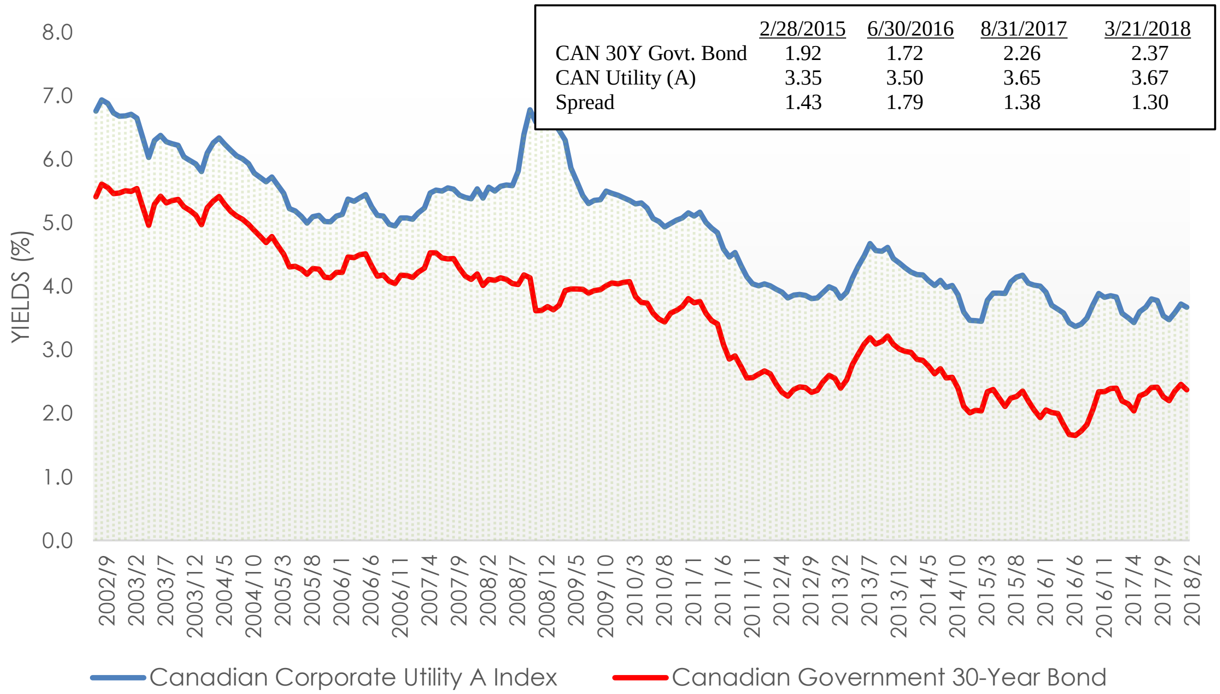
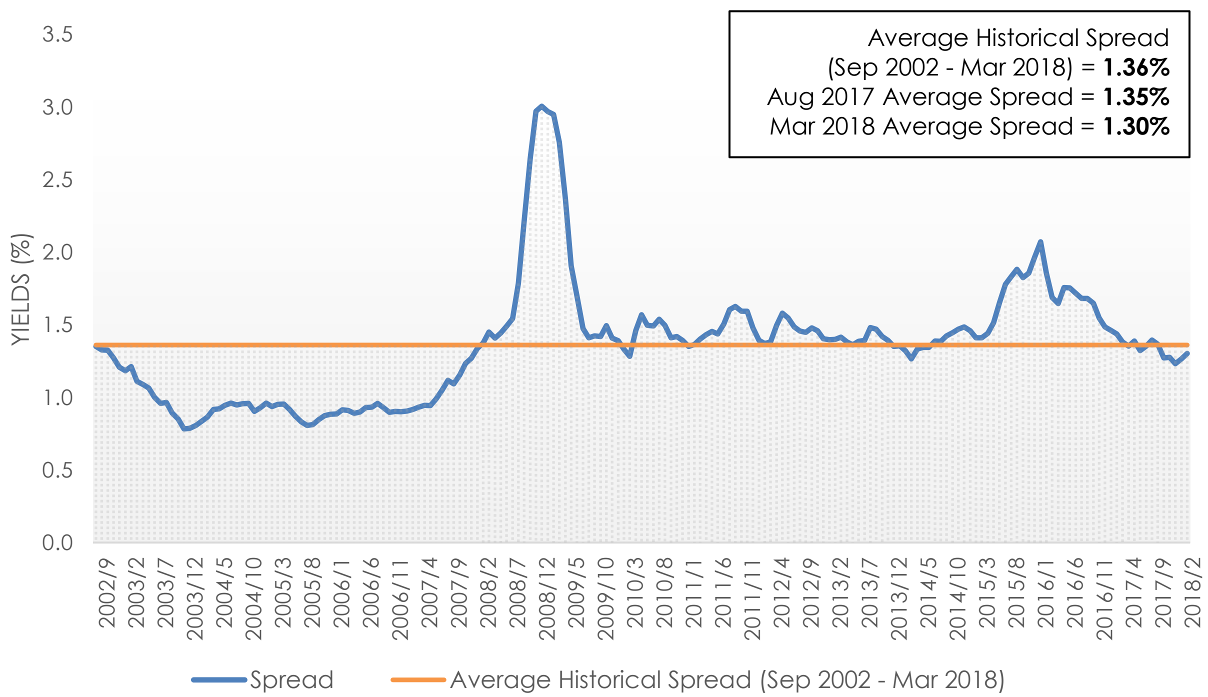


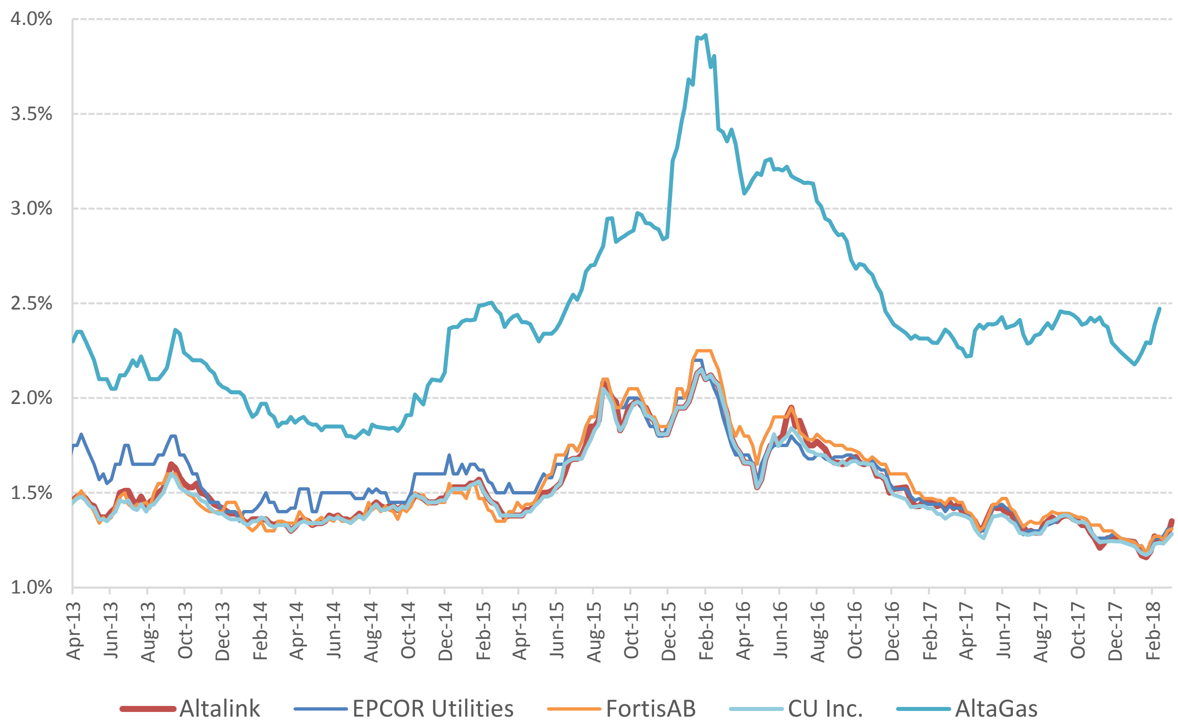
Figure 4 Credit spread between 30-year Canadian A-rated utility bond yields and 30-year GOC bond yields[220]



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]

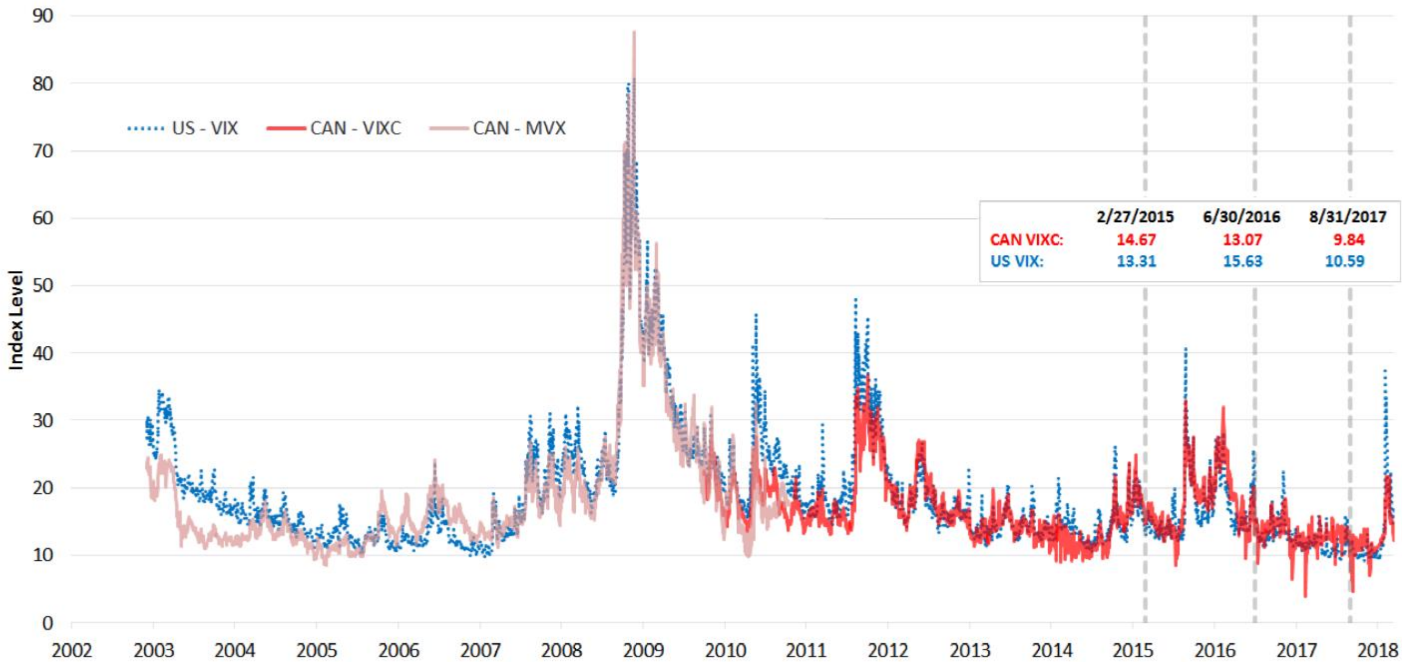
175. In the 2016 GCOC proceeding, the witnesses agreed that the long-term average for both the VIXC and VIX was about 20.[236] They further pointed out that volatility stayed at relatively low levels during 2013 and 2014, but in August 2015, the VIXC and VIX spiked to 33 and 40, levels not seen since 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]

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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

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[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]

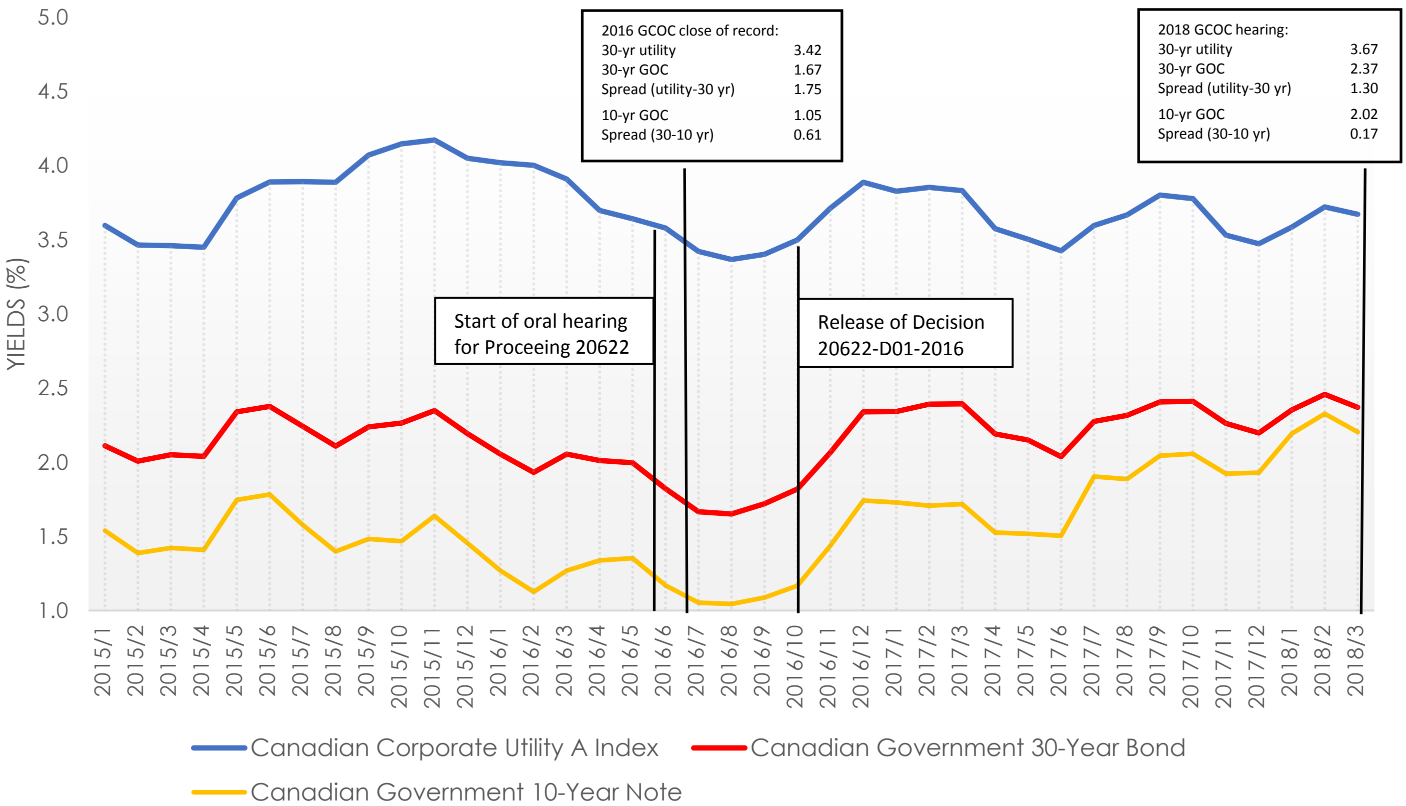
198. What is not as readily transparent is how these rising short-term interest rates should impact the Commission's determinations in setting the 2018 to 2020 ROE. As Dr. Cleary pointed out, central bank policy interest rates only tend to affect the "short end" of the yield curve[281] (Figure 1). The 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

[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.*

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[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:
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> > ... 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

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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]

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.

-The AUC' decision was prior to the FERC making the forward looking MERP official policy for all of its regulatory procedings, based on substantial evidence
-We have also estimated an average forward and historic MERP in the Alternative CAPM model
- With current and projected interest rates well below those dating back to 1924, why would one expect that data as being representative of a forward looking market return; the AUC acknowledges this on the next page
- the cost of capital for a regulated utility is a forward looking estimate, and in the case of Liberty may be in place for 10 years

436 Exhibit 22570-X0741.01, PDF page 42. Exhib
437 Transcript, Volume 6, page 1198. Exhibit 2257
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,

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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 conside
determining reasonable beta estimates

345. There was also considerable d
adjustment. In the 2013 GCOC decisi
widely disseminated to investors by i
and Merrill Lynch. However, the Con
whether an adjustment is warranted fo

- the AUC continues to struggle with the estimation procedure for betas
- the AUC after this decision listed this as a topic and invited evidence on the matter in its 2021 GCOC, and submissions were made by several experts, but unfortunately the AUC suspended the hearing and never heard the evidence
- in our experience, the Blume adjusted betas are routinely and broadly accepted by North American regulators, except where Dr. Booth or Dr. Cleary have advocated for judgemental approaches, or reversions to their own means
- the Commission ultimately relied predominantly on the adjusted betas submitted by the experts, see footnote 477 on pdf 82, it landed on 0.686 as its CAPM beta, which was slighter higher than that used by Mr. Coyne for his proxy groups.(see Table 4, pdf p.81)

346. The Commission has not been
superior to unadjusted betas in the co
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.

AUC: Rf 2.6/Beta 0.686/MERP 7.0/Float .50 = 7.9

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.

12 of the 13 beta estimates used by the AUC were adjusted betas from the experts, only one based on judgement and historical raw betas from Dr. Cleary

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,

[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]

- the risk premium model is used elsewhere and found to be both rigorous and helpful to regulators in determining allowed ROEs
- the FERC has adopted the risk premium model, as we have estimated it, to not only be acceptable, but as a cornerstone of its ROE determinations for public utilities under its jurisdiction
- the AUC seemed to be looking for assurance that it had been vetted and adopted elsewhere (see Para 400), now it has

398. In the 2 ... ht to Mr. Hevert's PRPM analysi ... his analysis, but expressed inte ... C proceedings.[521] In this proceeding, M ... s model.[522]

399. The Co ... RPM 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

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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, re

436. Dr. Cleary was the only
Mr. Hevert critiqued Dr. Clear
growth is an inferior measure o

- AUC rejected the single stage versions of the DCF from all experts, but endorsed the use of the multi-stage model, submitted by Mr. Coyne (see para 443 and 446)
- it also clearly rejected the approach adopted by Dr. Cleary using a similar approach to DR. Booth's work, relying on unreastically low "sustainable growth rates" (see para 439)

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 gro
Mr. Hevert described them as being
overall average long-term growth r
Commission considers that this lon
range of one to three per cent for in
exceeds Dr. Cleary's 2.83 per cent
Again, the Commission considers t
equity ownership if the expected lo
levels. Consequently, the Commiss
submitted by Dr. Cleary.

-The AUC' decision was prior to the FERC making the forward looking MERP official policy for all of its regulatory procedings, based on substantial evidence
-We have also estimated an average forward and historic MERP in the Alternative CAPM model
- With current and projected interest rates well below those dating back to 1924, why would one expect that data as being representative of a forward looking market return; the AUC acknowledges this on the next page
- the cost of capital for a regulated utility is a forward looking estimate, and in the case of Liberty may be in place for 10 years

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 Commissi
regarding return expe
utilities in Alberta. Ho
20622-D01-2016 beca

- no statistical basis for excluding outliers
-screening serves that purpose
-FERC does exclude outliers, with a well vetted and symetric approach, not just by pointing to some that are higher than others
High - 150% of median result from each model (prior to any exclusions)
Low - Baa utility bond yield plus 20% of the CAPM risk premium

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]

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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

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]

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]

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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.

[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

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]

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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.

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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.

[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.

[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

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[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,

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

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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) Company name of counsel or representative
AltaGas Utilities Inc. (AltaGas) MLT Aikins LLP
AltaLink Management Ltd. (AltaLink) Borden, Ladner Gervais LLP
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP
ATCO Gas & Pipelines Ltd. (ATCO Gas) (ATCO Pipelines) Bennett Jones LLP
Canadian Association of Petroleum Producers (CAPP)
Consumers' Coalition of Alberta (CCA) Wachowich & Co.
Direct Energy Marketing Limited (Direct)
ENMAX Power Corporation (ENMAX) Torys LLP
EPCOR Distribution & Transmission Inc. (EPCOR) Fasken Martineau Dumoulin LLP
EPCOR Energy Alberta GP Inc. (EEA)
FortisAlberta Inc. (FortisAlberta)
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Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP
The City of Calgary (Calgary) 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) Name of counsel or representative	Witnesses
AltaGas Utilities Inc. and ATCO Utilities R. Jeerakathil L. Smith, QC D. Sheehan	P. Carpenter B. Villadsen R. Buttke M. Stock G. Marghella
AltaGas Utilities Inc. (AltaGas) R. Jeerakathil	
AltaLink Management Ltd. (AltaLink), EPCOR Distribution & Transmission Inc. (EPCOR) and FortisAlberta Inc. (FortisAlberta) R. Block, QC J. Liteplo J. Hulecki L. Ho J. Hennig L. Mason	R. Hevert D. Koch C. Lomore R. Drotar S. Chaudhary J. Sullivan A. Johnson
AltaLink Management Ltd. (AltaLink) R. Block, QC	
ATCO Utilities: ATCO Electric Ltd., ATCO Gas and Pipelines Ltd. L. Smith, QC D. Sheehan	
ENMAX Power Corporation (ENMAX) D. Wood	J. Coyne A. Barrett J. McCoshen
EPCOR Distribution & Transmission Inc. (EPCOR) J. Liteplo J. Hulecki	
FortisAlberta Inc. (FortisAlberta) L. Ho J. Hennig L. Mason	
The City of Calgary (Calgary) D. Evanchuk	H. Johnson
Consumers' Coalition of Alberta (CCA) J. Wachowich, QC	J. Thygesen D. Madsen
Office of the Utilities Consumer Advocate (UCA) R. McCreary B. Schwanak	S. Cleary R. Bell

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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

2019 Island Regulatory and Appeals Commission Maritime Electric Company Ltd.

COMMISSION DE RÉGLEMENTATION ET D'APPELS DE L'ÎLE

THE ISLAND REGULATORY AND APPEALS COMMISSION
Prince Edward Island
Île-du-Prince-Édouard
CANADA

Docket: **UE20944**
Order: **UE19-08**

IN THE MATTER of an application by Maritime Electric Company, Limited for an Order of the Island Regulatory and Appeals Commission approving the rates, tolls and charges for electric service for the years March 1, 2019 to February 28, 2022, pursuant to section 20 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, and for certain approvals incidental thereto.

CERTIFIED A TRUE COPY

Jonah Clements,
General Counsel
Island Regulatory & Appeals Commission

BEFORE THE COMMISSION ON Friday, September 27, 2019.

J. Scott MacKenzie, Q.C., Chair
M. Douglas Clow, Vice-Chair
John Broderick, Commissioner

ORDER

IN THE MATTER of an application by Maritime Electric Company, Limited for an Order of the Island Regulatory and Appeals Commission approving the rates, tolls and charges for electric service for the years March 1, 2019 to February 28, 2022, pursuant to section 20 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, and for certain approvals incidental thereto.

CONTENTS

IN THE MATTER of an application by Maritime Electric Company, Limited for an Order of the Island Regulatory and Appeals Commission approving the rates, tolls and charges for electric service for the years March 1, 2019 to February 28, 2022, pursuant to section 20 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, and for certain approvals incidental thereto.

APPEARANCES & WITNESSES

1. **Maritime Electric Company, Limited**
   Counsel:
   D. Spencer Campbell, Q.C., Stewart McKelvey

   Witnesses:
   John D. Gaudet, P. Eng., President and Chief Executive Officer
   Angus S. Orford, P. Eng., Vice President – Corporate Planning and Energy Supply
   Jason C. Roberts, CPA, CA, Vice President – Finance and Chief Financial Officer
   Enrique Riveroll, Vice President – Customer Service
   John P. Trogonoski, Senior Project Manager, Concentric Energy Advisors, Inc.

2. **Interveners**
   (a) Prince Edward Island Energy Corporation
   Represented by Kim Horrelt, P. Eng., Director / Chief Executive Officer

   (b) Stephen Howard, MLA and Opposition Shadow Critic for Transportation, Infrastructure and Energy

3. **Public Participants**
   Roger D. King

4. **Island Regulatory and Appeals Commission**
   Counsel:
   Nicole M. McKenna, Carr, Stevenson & MacKay

   Financial Advisor:
   Michael D. Fitzpatrick, CPA, CA, Fitzpatrick & Co.

   Witnesses:
   Dr. Laurence D. Booth
   Mel Whalen, P. Eng., Multeese Consulting Incorporated

1 INTRODUCTION

1. On November 30, 2018, Maritime Electric Company, Limited ("MECL" or the "Company") filed an application with the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") seeking, among other things, approval of the rates, tolls and charges for electric service for the three year period from March 1, 2019 to February 28, 2022 (the "Application").

2. The Application is made pursuant to section 20 of the *Electric Power Act*, which provides as follows:

   20. Variation of rates, submission for review and approval

   (1) Whenever any public utility wishes to vary any existing rates, tolls or charges, or to establish any new rates, tolls or charges for any service, it shall submit for the review and approval of the Commission a schedule of such proposed rates, tolls and charges together with and appended thereto all rules and regulations which, in any manner, relate to the rates, tolls and charges; the Commission may approve, after reviewing the schedule and rules and regulations submitted, the schedule of rates, tolls and charges and the rules and regulations either in whole or in part, or may determine and fix new rates, tolls and charges, and amend the rules and regulations, as it sees fit.

3. In addition to the approval of rates, tolls and charges for electric service, MECL is seeking approval of a number of other matters that will impact electricity rates for its customers. The requested approvals relate to:

   - classification of costs related to Point Lepreau, on-Island generation fuel and wind power purchases;
   - decommissioning of the Charlottetown Thermal Generating Station and construction of a new balance of plant;
   - collection and deferral of certain energy related costs through the Energy Cost Adjustment Mechanism;
   - changes to amortization rates and the collection/deferral of the accumulated reserve variance; and
   - matters of cost allocation and rate design, including the proposed phasing-out of the declining second block rate for the Residential rate class.

4. On February 4, 2019, the Commission issued Order UE19-01, consolidating the following dockets with the Application, and directing that they be heard together with the Application as a single matter:

   - Point Lepreau Cost Allocation Classification Study in Commission Docket UE22502;
   - Charlottetown Thermal Generating Station Decommissioning Study in Commission Docket UE23001;
   - 2017 Depreciation Study in Commission Docket UE21604; and

- 2017 Cost Allocation Study in Commission Docket UE21222.

5. In its Application as filed in November 2018, the Company was seeking a 1.1 percent rate increase per year for the "typical" customer in each of its rate classes. This amounts to a cumulative rate increase of 3.3 percent over the proposed three year term (1.1 percent increase per year for three years).

6. The public hearing of the Application was scheduled to commence on August 6, 2019. On July 31, 2019 – six days prior to the hearing – MECL filed updated schedules with the Commission which included revised rates for electric service.

7. As part of the July 31, 2019 filing, MECL advised that it was seeking a reduced rate increase of 0.7 percent per year in each of the next three years. At the hearing, MECL advised that the actual proposed rate increase was 1.7 percent in year one, no increase in year two, and a 0.8 percent increase in year three.

2 PARTIES & PUBLIC PARTICIPATION

8. The rates charged for electric service are a matter that impacts all MECL customers and indirectly all Islanders. A rate increase, changes to the rate structure, or the elimination of the residential second block, can have significant financial implications for ratepayers.

9. As noted in previous Commission Orders, this Province does not have the benefit of a consumer advocate to represent the interests of ratepayers in hearings such as this. However, the Commission, in hearing this Application, did have the benefit of submissions from the Prince Edward Island Energy Corporation, Mr. Stephen Howard (MLA and Opposition Shadow Critic for Transportation, Infrastructure and Energy), and Mr. Roger King (interested member of the public).

10. Both the PEI Energy Corporation and Mr. Howard applied for, and were granted, intervener status as Friends of the Commission Interveners. A Friend of the Commission Intervener is an individual or organization who represents the public interest and who can meaningfully contribute to the proceeding.

11. In the present case, both the PEI Energy Corporation and Mr. Howard sought intervener status specifically to address matters of rate design and, in particular, matters relating to the residential second block rate. In both instances, MECL consented to the requests for intervener status.

12. The requests for intervener status came late in the proceedings. The PEI Energy Corporation applied for intervener status on June 27, 2019, and was granted intervener status by **Order UE19-05** dated July 4, 2019. Mr. Howard applied for intervener status on August 1, 2019 (five days before the hearing), and was granted intervener status by **Order UE19-06** dated August 2, 2019.

13. As the applications for intervener status were filed late in the proceeding, the interveners did not participate in the pre-hearing interrogatory process and did not call any witnesses at the hearing.

14. Mr. Roger King is an interested member of the public who takes an active role in matters of electricity regulation and who routinely participates in, or comments on, electric applications before the Commission. In the present Application, Mr. King requested the opportunity to ask clarifying questions of witnesses at the hearing and to make a

submission to the Commission. Mr. King was permitted to participate in the manner requested.

15. In an attempt to encourage public participation, the Commission also invited interested members of the public to submit written comments, and to participate in an evening session of the hearing that was held on August 8, 2019. The invitation to participate was published in local newspapers and via social media.

16. The Commission received more than thirty written submissions or comments from members of the public. The comments were submitted by individuals and industry, including the Seafood Processors Association of Prince Edward Island, the PEI Federation of Agriculture, and ECO-P.E.I. All comments received were published on the Commission website and made available to the parties.

17. In addition to the written comments, the Commission heard oral submissions from two interested members of the public, namely John te Raa and Margaret MacKay.

3 OVERVIEW OF PROCEEDING

18. In July 2018, the Commission was advised by MECL that the present Application would be filed in October 2018.

19. In anticipation of the Application, Commission Staff engaged the assistance of an independent expert, namely Synapse Energy Economics, Inc. ("Synapse"), to assist in the review of the proposed decommissioning of the Charlottetown Thermal Generating Station. Synapse was retained by Commission Staff in September 2018, and submitted its first round of interrogatories to MECL in October 2018.

20. On the understanding that the Application would be filed in October 2018, the Commission also scheduled tentative hearing dates for January 2019, with a view to having new rates in effect for March 1, 2019.

21. The Application was not, however, filed in October 2018 as expected. Instead, it was filed on Friday, November 30, 2018, and was received by the Commission Panel and Staff on Monday, December 3, 2018. Due to the late filing of the Application, the January hearing dates were untenable.

22. Upon review of the Application, it became apparent that Commission Staff required the assistance of additional experts to assist in reviewing the many collateral issues raised in the Application. In particular, the Commission Staff retained the services of Dr. Laurence Booth to assist in the review of the proposed return on average common equity, and the services of Multeese Consulting Incorporated (and its principal, Mel Whalen, P. Eng.) to assist on matters of cost allocation and rate design.

23. Both Dr. Booth and Mr. Whalen were retained in December 2018. They submitted their first round of interrogatories to MECL in early January 2019.

24. Upon review of the Application, Commission Staff determined that further details and particulars were required from MECL. As a result, the first round of interrogatories from Commission Staff were submitted to MECL on January 17, 2019.

25. Although the Application as filed was lengthy, there were numerous instances in which MECL did not provide sufficient information for the Commission to make an informed decision on the requested approvals. This resulted in an extensive interrogatory process. In total, Commission Staff submitted 89 interrogatories to MECL, while the experts

retained on behalf of Commission Staff submitted a total of 116 interrogatories to MECL. MECL filed responses to all 205 interrogatories.

26. In February 2019, the Commission canvassed the possibility of hearing dates for April 2019. MECL suggested that April hearing dates may be too soon. At that time, the interrogatory process was ongoing and the experts retained on behalf of Commission Staff had not yet filed their reports. As a result, hearing dates were tentatively scheduled for June 21 and June 24 to 28, 2019 (inclusive).

27. By May 2019, the interrogatory process was still ongoing and MECL anticipated filing further evidence. As a result, the Commission determined that the hearing could not reasonably proceed in June 2019. Instead, hearing dates were canvassed for July or August 2019. It was agreed that the dates of August 6 to 9, 2019 worked for MECL and all intended witnesses.

28. On July 5, 2019, a Notice of Hearing was published on the Commission website, local newspapers, and via social media.

29. A pre-hearing conference was held with the parties on July 24, 2019 to discuss procedural matters in advance of the hearing. At the pre-hearing conference, the parties agreed to accept the qualifications of all experts who filed reports with respect to the Application. The Commission agreed and accepted the qualifications of each of the experts.

30. The hearing of the Application took place over four days, between Tuesday, August 6, 2019 and Friday, August 9, 2019. A public session was held on the evening of Thursday, August 8, 2019, to allow interested members of the public the opportunity to provide their comments and input on the Application.

31. Members of the public also had the opportunity to submit written comments to the Commission on or before August 14, 2019.

4 RATES

32. In accordance with section 20(1) of the *Electric Power Act*, MECL is required to apply to the Commission when it wishes to vary the existing rates, tolls or charges for electric service. The Commission has the discretion to approve the rates, tolls and charges in whole or in part. Although section 20(1) provides little guidance on how the Commission should exercise its discretion, the preamble to the *Electric Power Act* states that the "*rates, tolls and charges for electric power should be reasonable, publicly justifiable, and non-discriminatory*".

33. In setting rates, the Commission must balance the interests of ratepayers and the interests of MECL. This duty was explained by the Supreme Court of Canada in the leading case of *Northwestern Utilities, Limited v. The City of Edmonton and Board of Public Utility Commissioners of Alberta*, [1929] SCC 186 [*Northwestern Utilities*] 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.*

4.1 Proposed Rates

34. In its Application as filed in November 2018, MECL was seeking approval of electric rates for a three year period, from March 1, 2019 to February 28, 2022.

35. At the time the Application was filed, MECL was proposing an annual rate increase of 1.1 percent for the "typical" customer in each of MECL's rate classes. This would have resulted in a cumulative rate increase of 3.3 percent over the proposed three year term (1.1 percent per year for three years).

36. MECL defines the "typical" Residential customer as consuming 650 kWh per month (7,800 kWh per year), and the "typical" General Service customer as consuming 10,000 kWh per month (120,000 kWh per year). Although MECL determined that the annual rate increase for a "typical" customer would be 1.1 percent, the ultimate impact on each customer would vary with their consumption and (if applicable) their demand.

37. The Company's proposed basic rates for electricity are derived primarily from the Company's annual revenue requirement. The annual revenue requirement is the amount required to recover MECL's forecast annual cost to provide electric service.

38. The Company's revenue requirement is forecast on an annual basis and is derived from each of the following:

- Forecast energy sales for the year;
- Forecast cost of generating or purchasing energy to meet energy sales;
- Forecast cost of delivering the energy to customers (the "wires" cost);
- Forecast amount of general and administrative expenses;
- Forecast fixed asset amortization expense;
- Forecast short-term and long-term interest expense;
- Income taxes; and
- Return on Average Common Equity.

39. Although a portion of the revenue requirement is collected from "Other Revenue" (such as Open Access Transmission Tariff (OATT) revenue, late payment charges, etc.), the majority of the Company's revenue requirement is collected from ratepayers through electric rates.

40. The Commission is not required to approve the Company's annual revenue requirement. However, because the proposed rates for electric service are derived from the revenue requirement, it is imperative that the Commission review each element of the revenue requirement to ensure that it is reasonable. If the Company's annual revenue requirement is not reasonable, then the rates derived from the revenue requirement are likewise not reasonable.

41. The Application as filed by MECL provided evidence on each aspect of the revenue requirement listed above. Prior to the hearing, the Commission and its expert witnesses engaged in an extensive interrogatory process with MECL to obtain the information needed for the Commission to make an informed decision with respect to the proposed rates.

42. In total, the pre-hearing interrogatory process spanned seven months and saw 205 interrogatories asked and answered. The volume of material produced and reviewed was

extensive. At the conclusion of the interrogatories, the record in this Application consisted of approximately 5,000 pages.

43. On July 31, 2019 – six days before the hearing commenced – MECL filed updated schedules and proposed a revised rate increase of 0.7 percent per year in each of the next three years. The Company also proposed to change the rate setting period to extend from September 1, 2019 to February 28, 2022.

44. In support of MECL's revised rates, the Company filed ten pages of paper. The ten pages consisted primarily of updated forecasts that varied substantially from the forecasts as filed by MECL in November 2018. In most instances, the Company provided little to no explanation for the change in its forecasts.

45. At the hearing of the Application, MECL advised the Commission that in April 2019, it updated its load forecast using a "revised methodology". According to the Company, in late 2018 and early 2019, it became apparent that sales were increasing at above forecast levels. This led MECL to revisit its load forecast methodology.

46. The revised methodology relates to the Residential components of the sales forecast. The Company's recent analysis shows that the penetration of electric heat in new residential construction is greater than 80 percent. As a result, the load forecast was revised to use housing starts as the main driver for growth in Residential sales.

47. The revised load forecast directly impacts MECL's forecast annual revenue requirement and, as a result, the rates proposed in this Application. Despite MECL having completed these revised forecasts in April 2019 while the interrogatory process was ongoing, the Company did not disclose this information to the Commission until July 31, 2019 – only six days before the hearing. In fact, the Commission was not advised until the first day of the hearing that the Company had revised its load forecast methodology from that which it historically used.

48. At the hearing, MECL also explained that although it stated in its July 31, 2019 filing that it was seeking an annual rate increase of 0.7 percent in each of the next three years, the actual rate impact to customers would not be 0.7 percent.

49. At the hearing, MECL advised that if the proposed rates are approved, the "typical" customer would see an average rate increase of 1.7 percent effective September 1, 2019, no increase in 2020, and a 0.8 percent increase in 2021. This represents a cumulative rate increase of 2.5 percent – not 2.1 percent as suggested by MECL.

50. MECL explained that the reason for the 1.7 percent increase effective September 1, 2019 is to allow the Company to recover its entire annual revenue requirement for 2019. Although the Company typically recovers its revenue requirement over a twelve month period, it is now seeking approval to recover its entire annual revenue requirement over a four month period (September 1 to December 31, 2019).

51. Although MECL suggested that a 1.7 percent increase was needed to recover its revenue requirement, it also confirmed at the hearing that it had notionally over-earned by $3.3 million in the first six months of 2019 (January 1 to June 30, 2019). The Company emphasized throughout the hearing that the balance of the Rate of Return Adjustment ("RORA") account, which represents the Company's over-earnings, could not be determined until year-end. As at June 30, 2019, the $3.3 million in over-earnings was a temporary or notional amount only. The Company reiterated that it does not forecast to over-earn in any year, and also does not forecast to over-earn in 2019.

52. After the hearing concluded, the Commission required MECL to file an updated **Schedule 15-1** which shows the actual rates it is proposing for each rate class. A comparison of the existing rates to the proposed rates show that the actual rate increase is more than 1.7 percent for 2019. Effective September 1, 2019, Residential customers, for example, would see a 1.76 percent rate increase on the first block rate, and a 1.95 percent rate increase on the second block rate. General Service customers would see a 1.66 percent increase on the first 5,000 kWh, and a 2.02 percent increase on the balance of the kWh consumed. Small Industrial customers would see a 1.69 percent increase on the first 100 kWh, and a 2.33 percent increase on the balance of the kWh consumed.

4.2 Findings

53. In this Application, MECL is seeking approval of rates, tolls and charges for electric service for a three year period. As explained in its reasons as part of the 2016 General Rate Application, the Commission supports multi-year ratemaking. Multi-year rates provide predictability and stability for ratepayers, while minimizing the cost of regulation – a cost which is ultimately borne by ratepayers.

54. The reasonableness of multi-year rates depends on the accuracy of the forecasts used to develop those rates. The ability to accurately forecast sales, revenue and expenses is therefore paramount to multi-year rate setting. If there is an error in the forecasts, then there is an error in the rates.

55. In the present Application, the Commission has serious concerns about the accuracy and reliability of the forecasts as presented by MECL. As the forecasts are used to develop rates, it follows that the Commission has serious concerns about the rates as proposed by MECL.

56. The Company initially filed an extensive application that addressed each aspect of the forecast annual revenue requirement. Upon review of the Application, Commission Staff and experts determined that additional information was required from MECL, including information to support and explain the Company's forecasts and related inputs. An extensive pre-hearing interrogatory process followed.

57. Then, six days before the hearing, MECL filed updated forecasts and revised rates for approval by the Commission. MECL provided little to no explanation or justification for the changes in its forecasts.

58. At the hearing, MECL advised that by late 2018 and early 2019, it became apparent that sales were increasing at above forecast levels. Although the Company filed this Application on November 30, 2018, its load forecasts for the period commencing January 2019 were, according to the Company, not representative of actual sales.

59. The changes to MECL's forecasts between November 2018 and April 2019 (a period of only five months) were significant. At the time this Application was filed in November 2018, the Company forecast sales growth for 2019 to be 2.6 percent. Five months later, in April 2019, the Company increased its forecast sales growth for 2019 from 2.6 percent to 3.8 percent. This represents a 46.5 percent increase in the sales forecast in a span of only five months.

60. Also in the Application as filed, MECL provided a forecast of the 2018 financial results which forecasted regulated net earnings of $13,788,300. At the time the Application was filed in November 2018, the Company had nine months of actual financial results for 2018 and, as a result, would only have estimated the remaining three months of the year.

61. In July 2019, MECL provided the Commission with the Company's actual results for the 2018 fiscal year. The actual results varied significantly from the forecast that was filed in November 2018. Specifically, the Company had under-estimated its 2018 total revenue by $8,145,576 and total expenses by $2,800,495. This resulted in an under-estimation of 2018 regulated net earnings in the amount of $5,345,081.

62. The Commission views this variance between forecast and actual results as significant, particularly since the Company was only required to forecast for approximately three months of the 2018 fiscal year. At the time of the July 2019 update, the Company provided no information or explanation as to why the 2018 actual results varied significantly from the Company's November 2018 forecast.

63. The Company's inability to accurately forecast sales and revenue only several months out calls into question the Company's ability to accurately forecast for the next three years. The Commission has no way to determine whether the revised load methodology developed by the Company in April 2019 is more accurate than the methodology used in November 2018.

64. The Commission's concerns are compounded by the level of over-earning that the Company has experienced since at least 2011. In 2011, the RORA account was introduced as part of the Energy Accord. The RORA account is used to defer excess earnings earned by the Company over and above its allowed rate of return.

65. As the Company over-earns, the balance of the RORA account grows. The Company is not entitled to keep the funds held in the RORA account; instead, the funds are refunded to ratepayers as ordered by the Commission.

66. At the time of the 2016 General Rate Application, the RORA account had a balance of more than $15 million. This is a significant sum. This means that during the Energy Accord, MECL earned $15 million more than its allowed rate of return. As part of the 2016 General Rate Application, MECL was ordered to refund the balance of RORA account to ratepayers over a three year period.

67. The Company also significantly over-earned during the last rate setting period. Between January 1, 2016 and December 31, 2018, the Company over-earned by approximately $10 million. In addition, at the hearing of this Application, MECL confirmed that between January 1 and June 30, 2019 (a period of six months), the Company has notionally over-earned by an additional $3.3 million.

68. It was the Company's position at the hearing that the $3.3 million in excess earnings for 2019 should not be considered by the Commission. According to the Company, due to seasonal fluctuations in their business, interim excess earnings may change significantly depending on the time of year and, as a result, the actual over-earnings cannot be determined until year-end. As at June 30, the $3.3 million is therefore a notional or temporary amount only. According to the Company, it is forecasting a zero RORA balance – meaning no over-earnings – for 2019.

69. The Company explained that it never forecasts to over-earn. As such, it is not forecasting any contributions to the RORA account over the next three years. The Company's witness, Mr. Jason Roberts, confirmed that the Company also did not forecast over-earnings during the last rate setting period. Yet the Company over-earned by approximately $10 million.

70. The Commission also questions why it was only provided with the revised schedules and rates days before the hearing, rather than in April 2019. By April 2019, the Company

realized that its forecasts were inaccurate to such an extent that it revisited its load growth forecasts and revised its methodology. Such a significant change in the load forecast would result in a significant change to the Company's forecast annual revenue requirement, and therefore, the rates as proposed in this Application. Although the Company was aware of these revised forecasts in April 2019, they were not disclosed to the Commission until six days prior to the hearing.

71. For all of these reasons, the Commission is not satisfied that the Company's forecasts as presented in this Application, and as revised on July 31, 2019, are reasonable, accurate or reliable. As such, the Commission is not prepared to approve the rates that are derived from those forecasts.

72. Instead, the Commission orders that the rates currently in effect for the period from March 1, 2018 to February 28, 2019, shall remain in effect until February 28, 2020. As such, there shall be no change in rates for any rate class until March 1, 2020.

73. In support of this finding, the Commission notes that based on the rates currently in effect, the Company has notionally over-earned by $3.3 million in the fist six months of the year. If the rates are increased, the level of over-earning will likewise increase.

74. The Commission also does not accept MECL's position that it does not forecast any over-earnings for 2019. Although the Company does not forecast to over-earn in any year, the reality is that MECL has over-earned by more than $25 million since 2011. This again calls into question the accuracy and reliability of the Company's forecasts.

75. Further, certain decisions made in this Order and discussed following will have the effect of decreasing the Company's expenses for 2019, while increasing its revenues. As such, with efficient management, the Company should be in a position to recover its revenue requirement for 2019, including its allowed rate of return, based on existing rates.

76. The Commission continues to support multi-year ratemaking and views this to be in the best interests of the Company and of ratepayers. As a result, and despite the Commission's concerns with the forecasts as presented, the Commission is prepared to set rates effective March 1, 2020 and March 1, 2021.

77. As part of this Order, the Commission has determined the relevant components of MECL's revenue requirement for 2019, 2020 and 2021, including the allowed rate of return, common equity component, and amortization expense. The determinations and approvals set forth in this Order will impact the rates effective March 1, 2020 and March 1, 2021. The full particulars of the Commission's findings and the resulting Order follow.

78. However, due to the Commission's concerns regarding the forecasts as presented by MECL, the actual rates for each rate class effective March 1, 2020 and March 1, 2021 shall be determined upon the Company filing updated financial information as at December 31, 2019. The updated financial information shall be filed with the Commission on or before **January 31, 2020.** The form and content of the financial information shall be determined by the Commission.

79. As discussed in the following reasons, the Company shall be required to use the full amount of the post-2015 RORA account, together with interest earned (approximately $10 million), to minimize the proposed rate increase for the period from March 1, 2020 to February 28, 2021. In the event the balance of the post-2015 RORA account is sufficient to ensure that there is no rate increase effective March 1, 2020, yet there is still a balance remaining in the post-2015 RORA account, the remaining balance shall be refunded to

ratepayers during the period from March 1, 2021 to February 28, 2022. The refund rates shall be such that the post-2015 RORA account shall be fully refunded to ratepayers, and shall therefore have a zero balance, on or before February 28, 2022.

80. The Commission notes that the rates as proposed by MECL assume the continuation of the Clean Energy Price Incentive for the next three years. The Clean Energy Price Incentive is a Provincial Government rebate of ten percent on the first 2,000 kWh per month of energy consumed by Residential customers. Although MECL *assumes* the Incentive will continue for the next three years, it has no assurance from the Provincial Government at this time.

81. The Clean Energy Price Incentive has a significant impact on the monthly electric bill for Residential customers. The Commission therefore encourages MECL and the Provincial Government to determine whether the Incentive will continue during the rate setting period.

5 GENERAL RULES & REGULATIONS

82. In accordance with section 20(1) of the *Electric Power Act*, MECL is required to file with its General Rate Application a copy of "*all rules and regulations which, in any manner, relate to the rates, tolls and charges*". The rules and regulations are subject to approval by the Commission, pursuant to section 13 of the *Electric Power Act*, which provides:

> ***13. Service rules and regulations, powers of Commission***
>
> *(1) All rules and regulations of any public utility relating to the kind of service to be supplied to customers and the manner by which the service shall be supplied, shall be subject to approval by the Commission and after approval, those rules and regulations shall govern the service.*
>
> ***Commission, power to make rules***
>
> *(2) Notwithstanding subsection (1), the Commission may make rules and regulations relating to the kind of service and the manner by which the service shall be supplied to customers of a public utility.*

5.1 Proposed Amendments

83. MECL has filed amended General Rules and Regulations as part of the Application and is seeking Commission approval of the proposed amendments.

84. The amendments proposed by MECL are intended to incorporate the changes to the Residential monthly service charge, the ECAM base rate, and the rates for each rate class, as proposed by MECL in the Application.

85. In addition, MECL seeks to amend the Large Industrial Rate Schedule Guidelines to reflect a more accurate and complete description of the charges that may be applied to the Large Industrial customer based on the voltage level of service provided.

5.2 Findings

86. The Commission approves the amendments to the Large Industrial Rate Schedule Guidelines as proposed by MECL in the Application. The General Rules and Regulations shall also be amended to incorporate the terms of this Order, including the Residential

monthly service charge, the ECAM base rate, and the rates for each rate class as ordered by the Commission.

87. The amended General Rules and Regulations shall be filed with the Commission on or before **October 31, 2019**.

6 RATE OF RETURN

88. As a regulated public utility, MECL is entitled to earn a fair return on its assets that are used and useful in the production, transmission, distribution and furnishing of electric energy.

89. The return on investment that MECL is entitled to earn is determined by the Commission in accordance with the *Electric Power Act*. Section 24(1) of the *Electric Power Act* states as follows:

> ***24. Return on investment, utility authorized to earn certain, computation of***
>
> *(1) Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, computed by using the rate base as fixed and determined by the Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Commission according to this Act and the rules and regulations made by the Commission hereunder.*

90. The *Electric Power Act* directs that the rate of return shall be computed based on the Company's rate base. As a result, before establishing a rate of return, the Commission must first determine the value of the Company's rate base.

91. The Company's rate base is the value of its assets that are used and useful in the production, transmission, distribution and furnishing of electric energy. These are the assets on which MECL is entitled to earn a rate of return. Section 21(2) of the *Electric Power Act* provides:

> *In establishing a rate base, the Commission shall determine the value of the assets, used and useful, of the public utility in the production, transmission, distribution and furnishing of electric energy, on the basis of the prudent original cost thereof, deducting therefrom the amount of the accrued depreciation of such property and assets as determined by the Commission.*

92. Once the Company's rate base has been determined, the Commission must then determine a rate of return that is just and reasonable. This requires the Commission to balance the interests of ratepayers and the interests of the utility.

93. The Supreme Court of Canada has defined a "fair return" for a regulated utility as follows:

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

(see *Northwestern Utilities*)

94. Although the *Electric Power Act* states that MECL is entitled to earn a just and reasonable return on rate base, the Company has requested approval of a return on average common equity – rather than a return on rate base.

95. In support of its request, MECL explained that since returning to cost of service regulation in 2004, the Company's maximum allowable rate of return has been based on average common equity. As a result, the Company is seeking approval of a return on average common equity in the present Application.

96. The Commission notes that in the 2016 General Rate Application, MECL sought approval of a return on average common equity, approval of its rate base, and approval of a return on average rate base within an allowed range.

97. As part of its initial filing in the 2016 General Rate Application, MECL sought a return on average common equity ("ROE") of 9.7 percent within an allowed range of 9.5 percent to 9.9 percent

98. After filing its initial application in 2015, MECL and the Province entered into an agreement concerning electric rates (the "2016 Rate Agreement"). As a result of the Agreement, MECL amended its initial application and instead sought an ROE of 9.35 percent based on 40 percent average common equity.

99. The Commission approved the return on average common equity of 9.35 percent based on 40 percent average common equity. In doing so, the Commission noted that an ROE of 9.35 percent represented a reduction of 0.4 percent from the legislated ROE of 9.75 percent in effect during the Energy Accord. The reduction was also consistent with approved ROEs in other Canadian jurisdictions, including in Atlantic Canada.

100. As part of the 2016 General Rate Application, the Commission also found that an ROE "risk premium" was appropriate. The risk premium was based on MECL's unique risk factors, including the risk associated with frequent changes to the regulatory framework in this Province. The Commission refused to assign a value to the risk premium, noting that it should be assessed based on the circumstances of each rate application.

6.1 Proposed Return on Average Common Equity

101. In the present Application, MECL is seeking approval of a "target" ROE of 9.35 percent based on 40 percent common equity for 2019, 2020 and 2021. The Company is also requesting approval of an "earnings sharing mechanism" in the form of an allowed ROE range of plus or minus 50 basis points around the authorized ROE.

102. In support of its proposed ROE and earnings sharing mechanism, MECL filed an expert report prepared by John P. Trogonoski of Concentric Energy Advisors, Inc. Mr. Trogonoski was also called as a witness at the hearing and presented oral evidence to the Commission.

103. Mr. Trogonoski estimated that MECL's required cost of equity is within a range of 9.20 percent to 9.90 percent based on proxy groups from Canada, the United States and North America. He therefore concluded that MECL's proposed ROE of 9.35 percent was "*reasonable, if not conservative*".

104. In his report, Mr. Trogonoski also commented on MECL's unique risk factors. These risk factors include:

- The Company's small size relative to other electric utilities in Canada and the U.S.;
- Macroeconomic and demographic trends in PEI and Canada generally;
- Operating risks within the Company's service territory, including power supply risks and the prevalence of severe weather conditions;
- The existence of deferral and variance accounts that protect the Company against risks from events that are material in nature and beyond the control of management; and
- Risks related to competition from alternative fuel sources.

105. Mr. Trogonoski concluded that while MECL's volumetric risk has been reduced due to the implementation of the Weather Normalization Mechanism (discussed following), MECL's business risk remains relatively high compared to other companies in the Canadian and U.S. proxy groups.

106. Dr. Laurence Booth was retained by Commission Staff to present expert evidence on the proposed ROE. Dr. Booth filed an expert report and was called as a witness at the hearing on behalf of Commission Staff.

107. Dr. Booth, unlike Mr. Trogonoski, classifies MECL as being a low risk Canadian utility. In particular, Dr. Booth does not view MECL's size as a risk factor, noting that size does not influence MECL's ability to earn its allowed ROE, nor does it affect MECL's access to bond markets.

108. Dr. Booth also views regulatory and government involvement in this Province as being positive. He noted, for example, that the Provincial Government essentially funded the cost of the Point Lepreau refurbishment, thereby taking the liability off MECL's books. As a further example, Dr. Booth explained that the Government owned the new submarine cables and leased them to MECL, further reducing risk to the Company.

109. Dr. Booth and Mr. Trogonoski also take different approaches to the determination of a just and reasonable rate of return for a regulated utility. While Mr. Trogonoski places emphasis on proxy groups and allowed ROEs for other regulated entities, Dr. Booth focuses on the widely-accepted capital asset pricing model ("CAPM") and discounted cash flow ("DCF") analysis to determine the allowed ROE.

110. According to Dr. Booth, the definition of a "fair return" in Canada does not require a regulator to follow the allowed ROEs of other utilities. Further, Dr. Booth generally does not recommend that regulators follow other regulators in setting the approved ROE, as he views the process as being circular.

111. In his direct evidence, Dr. Booth identified a number of areas in which he and Mr. Trogonoski disagreed on the assumptions to be used in the CAPM and DCF analysis. In particular, Dr. Booth did not agree with Mr. Trogonoski's use of the DCF constant growth model. He explained that in its August 2018 decision, the Alberta Utilities Commission ("AUC") refused to accept the constant growth model as presented by Mr. Trogonoski's colleague (Mr. James Coyne) as the growth rate estimates were unreasonable.

112. Further, Dr. Booth did not agree with Mr. Trogonoski's adjustment of the beta toward one. Dr. Booth again relied on an earlier AUC decision in which the evidence of Mr. Coyne was rejected due to unreasonably high beta results caused by his adjustment toward one.

113. Dr. Booth ultimately concluded that an allowed ROE of 7.5 percent based on 35 percent common equity is just and reasonable for MECL. However, he recommended that the Commission move to the "halfway house" and approve an allowed ROE of 8.5 percent based on 37 percent common equity. In support of this position, Dr. Booth noted that in August 2018, the AUC approved an allowed ROE of 8.5 percent based on 37 percent common equity for Alberta transmission and distribution companies. According to Dr. Booth, Alberta transmission and distribution companies are comparable to MECL.

6.2 Proposed Common Equity Component

114. Recent amendments to the *Electric Power Act* require MECL to maintain a common equity component within a range of 35 percent to 40 percent.

115. MECL is seeking approval of 40 percent common equity for the purposes of determining its annual revenue requirement. According to MECL, the common equity component of its capital structure will fluctuate between 39 percent and 40 percent.

116. Mr. Trogonoski explained that the cost of common equity depends in part on the Company's capital structure. As a result, the equity ratio and rate of return must be considered together. According to Mr. Trogonoski, other factors being equal, firms with lower common equity ratios require higher rates of return to compensate shareholders for the risks associated with higher financial leverage. Mr. Trogonoski concluded that MECL's proposed common equity ratio of 40 percent is lower than that justified by its risk profile.

117. Unlike Mr. Trogonoski, Dr. Booth concludes that 35 percent common equity is fair and reasonable for MECL. Dr. Booth also noted that given a range of common equity, a utility will invariably use the high end of the range. Using a higher common equity component allows a utility to maximize its capital investment, thereby increasing its rate base and maximizing its return.

6.3 Proposed Earnings Sharing Mechanism

118. MECL is seeking Commission approval to introduce an earnings sharing mechanism. The proposed mechanism introduces a "deadband" of plus or minus 50 basis points around the authorized ROE.

119. Under the proposed mechanism, the Company would receive the benefit of surplus earnings and assume the risk of an earnings shortfall within the deadband from 8.85 percent to 9.85 percent. For earnings greater than 9.85 percent, the Company would share 100 percent of those excess earnings with customers. For earnings below 8.85 percent, MECL would be allowed to raise customer rates in the following rate year in order to provide the Company with an earned ROE of 8.85 percent.

120. According to Mr. Trogonoski, the primary purpose of an earnings sharing mechanism is to share with customers earnings that deviate in a meaningful way (either positive or negative) from the level of earnings associated with the authorized ROE. He notes that the RORA account (discussed following) requires MECL to return 100 percent of earnings above the allowed ROE to customers, and places a "hard cap" on MECL's earnings. There is therefore no financial incentive for MECL to seek cost savings and operating efficiencies.

6.4 Findings

121. The Commission has weighed the expert evidence of Dr. Booth and Mr. Trogonoski and finds that where their evidence differs the Commission prefers and accepts the expert

evidence of Dr. Booth. Although Dr. Booth recommended a ROE of 8.50 percent on 37 percent equity, the Commission is prepared to allow the Company's current allowed ROE of 9.35 percent based on 40 percent average common equity to remain in place. The Commission is continuing this ROE due to the other changes being made in this Order which may have the effect of slightly increasing the Company's risk. Therefore, in the interest of fairness to the Company, the Commission is not decreasing the allowed ROE.

122. As a result, MECL shall be entitled to earn a *maximum* return on average common equity of 9.35 percent based on 40 percent average common equity in each of 2019, 2020 and 2021. The allowed ROE and common equity component shall continue until varied by the Commission.

123. The Commission is not, however, satisfied that the proposed earnings sharing mechanism is just and reasonable. MECL has previously requested Commission approval of an earnings sharing mechanism as part of its 2006 and 2016 General Rate Applications. To date, the Commission has refused such requests.

124. The Commission has serious concerns about the impact that an earnings sharing mechanism would have on the balance of the RORA account and the amount of over-earnings that are refunded to ratepayers. Since at least 2011, when the RORA account was introduced as part of the Energy Accord, MECL has over-earned by millions of dollars a year. At present, the full amount of the over-earnings is credited to the RORA account and refunded to ratepayers, with interest.

125. Due to MECL's pattern of over-earning, the Commission believes that the approval of the earnings sharing mechanism would amount to approval of an allowed ROE of 9.85 percent. The end result would be a higher rate of return for the Company, and a corresponding decrease in the amount of over-earnings refunded to ratepayers.

126. Further, as a result of MECL's pattern of over-earning, the earnings sharing mechanism is not likely to achieve its stated purpose of encouraging cost savings and operating efficiencies.

127. In addition, the Commission is not satisfied that MECL has provided sufficient justification for an earnings sharing mechanism at this time. There is no calculation of the realized earnings for the preceding twelve-month period which, according to Mr. Trogonoski, is the starting point for any earnings sharing mechanism. Nor is there any justification for the proposed deadband of 50 basis points.

128. Instead, the only justification provided by MECL is that earnings sharing mechanisms have been approved by other Canadian regulators. The Commission is not bound by the decisions of other regulators, and does not find them to be persuasive in the present circumstances.

129. For these reasons, the Commission does not approve the earnings sharing mechanism as proposed by MECL. Instead, MECL shall be entitled to earn a *maximum* return on average common equity of 9.35 percent based on 40 percent average common equity. Any over-earnings during the rate setting period shall be deposited to the RORA account for refund to ratepayers (with interest) in the manner set out in this Order.

DEFERRAL ACCOUNTS

7 ENERGY COST ADJUSTMENT MECHANISM

130. MECL has had a mechanism to recover/rebate energy costs above/below a base amount in place since the 1970s. The mechanism, currently referred to as the Energy Cost Adjustment Mechanism ("ECAM"), is intended to provide a smoothing effect to the collection or rebate of energy costs. It enables MECL to collect/return fluctuations in approved energy related costs above/below the forecast base amount per kWh included in the basic rates.

131. Under the operation of the ECAM, MECL charges to expense, on a monthly basis, an amount equal to the net purchased and produced energy for the month, multiplied by a base rate per kWh. This amount is subtracted from the actual cost of energy purchased or produced during the month. The difference (positive or negative) is then added to the Company's balance sheet for future recovery from, or return to, ratepayers over a period of time and as approved by the Commission.

7.1 Murphy Report (December 2004)

132. The ECAM (in its current form) was approved by the Commission in 2005 on an interim and transitional basis (see **Orders UE05-01** and **UE05-05**). At that time, the Commission expressed concern about the expenses and accounts that MECL sought to recover through the ECAM. As a result, the Commission retained the services of John Murphy, MBA, P. Eng., to comment on the appropriateness of the proposed mechanism and the eligible components of an ECAM. The report was filed with the Commission in December 2004 (the "Murphy Report").

133. As explained by Mr. Murphy, the costs included in an ECAM should only contain changes in price-level relating to prudently incurred costs for fuel delivered to a utility's generating stations and for the variable cost component of purchased electrical energy.

134. As a result, an ECAM should only include variable cost components of purchased energy, or costs that are subject to periodic fluctuations and not susceptible to precise determination. As explained by Mr. Murphy, the following tests must be satisfied in determining whether an expense properly belongs in ECAM:

> *A concise definition of ECAM expenses, as noted above, is a utility's reasonably and prudently incurred costs for fuel delivered to its generating stations and all of its reasonably and prudently incurred costs for the variable cost component of purchased electrical energy for its retail customers. The other principal test is that such costs are subject to periodic fluctuations and are not susceptible to precise determinations in rate cases prior to the time such costs are incurred. Both of these tests should be satisfied when deciding what belongs in ECAM, however, it needs to be recognized that the first one is the principal test and the second represents a secondary level of screening.*

135. Mr. Murphy undertook an analysis of each component that MECL intended to recover through the proposed ECAM. He noted that certain categories of costs should <u>not</u> properly be recovered through ECAM, including the following:

1) Costs for the volume of energy above the budget level;

2) Costs associated with ancillary services and short-term capacity payments;

3) Payments to New Brunswick Power relating to assets dedicated to the interconnection;

4) O&M costs relating to MECL generating stations and the Energy Control Centre; and

5) The amortization of the Point Lepreau write-down.

136. As explained by Mr. Murphy, when non-traditional ECAM costs are recovered through the ECAM, it removes the direct financial incentive for the utility to optimize its decision making process regarding the management of those costs (i.e. there is no financial incentive to minimize costs). Further, it puts the regulator in a situation where it must continually pass judgment as to the prudence of such expenditures after the fact.

137. As a result, Mr. Murphy recommended that the ECAM should be approved on a temporary basis only, until such time as the basic rates could be adjusted to incorporate the costs that should not properly be recovered through the ECAM.

7.2 Subsequent Commission Orders

138. The Commission acknowledged Mr. Murphy's concerns and recommendations and, by **Order UE05-05** dated March 16, 2005, approved the ECAM on an "*interim and transitional basis*".

139. The Commission allowed the interim ECAM to continue in effect until June 30, 2006. However, the Commission directed that the ECAM "*will be replaced with an ECAM that reflects a reduced number of accounts, yet to be determined, that will be subject to ECAM adjustment*" (see **Order UE05-06**).

140. In June 2006, the Commission again expressed concern about the costs being recovered through ECAM, and cited the concerns and recommendations of Mr. Murphy (see **Order UE06-03**). In response, MECL asked that the Commission defer any changes to the ECAM pending receipt and review of:

1) A depreciation study and cost allocation study;

2) New energy supply agreements; and

3) The refurbishment costs associated with Point Lepreau.

The Commission agreed to defer changes to the ECAM and ordered the continuation of the ECAM on an interim and transitional basis.

141. By January 2008, the ECAM remained in effect on an interim basis. In accordance with Commission **Order UE08-01**, MECL was required to file a report with the Commission by September 1, 2008 providing recommendations for re-basing the ECAM and the transition of certain costs from inclusion in ECAM to inclusion in basic rates.

142. In its 2009 General Rate Application, MECL sought to defer and amortize its forecast replacement costs associated with the refurbishment of Point Lepreau through ECAM. The Commission again expressed concern about the collection of these amounts through ECAM. Instead, the Commission ordered that the costs would be deferred, and that MECL would file a report with the Commission outlining all options for recovery, including whether the costs should be recovered through ECAM or basic rates (see **Order UE09-02**).

7.3 Current Rate Application

143. In the present Application, MECL is seeking to rebase the ECAM base rate and to recover certain additional expenses through the ECAM. These additional expenses relate to Provincial Costs Recoverable for the closure of Dalhousie and the refurbishment at Point Lepreau.

144. The Provincial Costs Recoverable have historically been collected as a rate rider included in customer electricity rates. According to MECL, recovery of the Provincial Costs Recoverable through the ECAM "*will eliminate the variability in the monthly repayment amount associated with a rate rider based on monthly consumption levels*".

145. At the hearing, MECL confirmed that it now recovers all energy related costs through the ECAM, rather than through basic rates. MECL explained that it views the ECAM as a "rate stabilization mechanism". As such, it uses the ECAM to defer and amortize a portion of the annual energy costs. The result is that ratepayers are not paying the full cost of the energy consumed by them; instead, a portion of the cost is deferred for collection from future ratepayers.

146. As of June 30, 2019, the ECAM had a balance of $4.252 million recoverable from ratepayers. This means that between 2016 and June 2019, ratepayers paid $4.252 million less than the actual cost to supply the energy used by them. These deferred energy costs must now be borne by future ratepayers.

147. At the public session of the hearing, Mr. John te Raa spoke about this particular issue. He noted that since at least 2010, himself and others have expressed concern about the deferral of energy costs through the ECAM. The end result is that the energy charges do not reflect the true supply cost of energy, and do not send appropriate price signals to consumers regarding energy charges.

148. At the hearing, MECL confirmed that the balance of the ECAM recoverable from ratepayers is a regulatory asset. As a result, MECL earns a 9.35 percent annual rate of return on the $4.252 million balance of the ECAM account.

7.4 Findings

149. The Commission is not prepared to allow the recovery of Provincial Costs Recoverable through the ECAM, and is not prepared to allow the corresponding re-basing of the ECAM base rate to include the Provincial Costs Recoverable. Instead, the Provincial Costs Recoverable shall continue to be collected through a rate rider in basic rates. MECL confirmed that this will have no impact on the proposed rates.

150. In support of this finding, the Commission notes that the Provincial Costs Recoverable are a known and fixed amount to be recovered from ratepayers. As the amount recoverable is not subject to fluctuate, it can properly be collected through basic rates. The Commission is therefore satisfied that the Provincial Costs Recoverable should continue to be collected through a rate rider in basic rates. MECL did not provide any compelling evidence as to why this practice should change.

151. The Commission also has serious concerns about the use and continued existence of the ECAM. The ECAM, in its current form, was approved by the Commission in 2005 on an interim and transitional basis. It was not intended to be used as a "rate stabilization mechanism", as suggested by MECL, nor was it intended to be used to recover all energy related costs.

152. The purpose of the ECAM is to capture variations in energy supply costs. During the 1970s and 1980s, the Fuel Adjustment Mechanism (as it was then called) was an important rate smoothing mechanism used to help alleviate significant fluctuations in fossil fuel costs. At that time, the Company generated all of the energy supply requirements on-Island using fossil fuel. That is no longer the case.

153. MECL currently purchases the majority of its energy from New Brunswick Energy Marketing, and has recently entered into a five year Energy Purchase Agreement for the period from March 1, 2019 to February 29, 2024. As a result, the Company is able to reasonably estimate the average unit cost of a significant portion of its annual energy purchases during the rate setting period.

154. MECL notes that the Company may still experience unplanned events, such as curtailments, changes in wind generation output or unplanned outages at Point Lepreau, which can affect the annual cost of purchased and produced energy. However, by collecting these expenses through ECAM, there is no incentive for MECL to minimize costs. Instead, MECL will be entitled to recover the full amount of the expenses from ratepayers with little to no regulatory oversight.

155. The Commission's concerns are compounded by the growing balance of the ECAM account. Between 2016 and 2018, the ECAM balance ranged from $2.158 million to $3.976 million, notwithstanding the existence of an Energy Purchase Agreement that should have allowed MECL to forecast its energy supply costs with reasonable certainty.

156. The growing balance of the ECAM is of concern to the Commission for several reasons. The first is that it clearly shows that present-day ratepayers are not paying the full cost to supply the energy consumed by them. Instead, a portion of the energy cost is being deferred for collection from future ratepayers. The Commission finds that this practice is not equitable and does not send the appropriate price signals.

157. A further concern is the fact that MECL is entitled to earn a rate of return on the balance of the ECAM recoverable from ratepayers. As a result, there is a financial incentive for the Company to continue to defer energy supply costs rather than collect them from present-day ratepayers.

158. The Commission notes, for example, that in determining the ECAM base rate, MECL applies a "rate stability adjustment". The rate stability adjustment adjusts the energy supply cost per kWh downward, such that the ECAM base rate is less than MECL's actual energy supply cost. Because the ECAM base rate is less than the energy supply cost, the ECAM will always show an amount recoverable from (rather than payable to) ratepayers. The amount recoverable from ratepayers is identified as a regulatory asset on MECL's balance sheet, and ultimately increases the Company's average common equity and its corresponding return.

159. In addition, the Commission questions the continuing value of retaining both the ECAM and the RORA account (discussed following). As the ECAM has a balance recoverable from ratepayers, and the RORA account has a much greater balance payable to ratepayers, the funds in the RORA account could, in theory, be used to off-set and eliminate the balance of the ECAM in its entirety. Such an off-setting would be in accordance with accepted accounting principles.

160. In light of these concerns, the Commission requires MECL to undertake a thorough and comprehensive review of the ECAM as it currently exists, including the expenses and accounts that are currently collected through the ECAM, and the practice of deferring a

portion of energy supply costs for collection from future ratepayers. MECL shall file its review, together with any resulting recommendations, with the Commission on or before **April 1, 2020**.

8 RATE OF RETURN ADJUSTMENT

161. The RORA account was implemented by Commission **Order UE11-04** in December 2011, being the first year of the Energy Accord. During the Accord, MECL recognized that in the absence of regulatory adjustment, it would have exceeded the allowed 9.75 percent return on average common equity.

162. The RORA account was created to defer, with interest, any over-earnings by MECL during the term of the Energy Accord. In accordance with the Accord, these excess earnings were to be returned to customers, with interest, at the conclusion of the Energy Accord.

163. On March 1, 2013, MECL began refunding to customers the actual 2011 RORA and the forecast 2012 RORA at the rate of $0.00071 per kWh. MECL also recorded a RORA in 2013, 2014 and 2015, being the final three years of the Accord.

164. According to MECL, the excess earnings during the Energy Accord were due to higher than forecast sales growth, driven primarily by the accelerated adoption of electricity based sources for space heating.

165. At the time of the 2016 General Rate Application, the RORA account had a balance of $15,156,765 as at December 31, 2015. MECL did not provide an updated forecast for January and February 2016.

166. As part of the 2016 General Rate Application and the 2016 Rate Agreement, MECL proposed that the balance of the RORA account be refunded to ratepayers over a three year period, from March 1, 2016 to February 28, 2019.

167. The Commission approved the refund of the RORA account at the following rates:

	March 1, 2016	March 1, 2017	March 1, 2018
RORA Rebate per kWh ($)	0.00410	0.00473	0.00345

168. As a result, current electricity rates charged to MECL customers reflect the refund of the RORA account at the approved rates.

169. In **Order UE16-04**, the Commission also ordered MECL to establish a separate RORA account for any over-earnings during the period from March 1, 2016 to February 28, 2019. MECL was required to report the balance of the new RORA account to the Commission on a monthly and annual basis.

170. As of December 31, 2018, the RORA account balance (with interest) stood at $10.352 million. This represents the amount by which MECL over-earned (i.e. earned above its allowed ROE of 9.35 percent) during the period from January 1, 2016 to December 31, 2018.

171. In total, MECL over-earned by $2.1 million in 2016, $2.77 million in 2017, and $5.24 million in 2018. This is summarized in the **Updated Schedule 5-5** (reproduced below) which was filed by the Company on July 31, 2019:

Schedule 5-5 Post-2015 RORA Payable to Customers ($)				
	RORA	**Interest***	**Refunded to Customers**	**Balance Owing to Customers**
2016	$ 2,100,000	$ -	$ -	$ 2,100,000
2017	2,767,885	61,922	-	4,929,807
2018	5,239,809	182,419	-	10,352,035
2019 (Jan 1 – June 30)	-	200,135	779,485	9,772,685
Total	**$ 10,107,694**	**$ 444,476**	**$ 779,485**	**$ 9,772,685**

** Calculated monthly based on the Scotiabank prime rate*

172. In addition, MECL advised that it has over-earned by approximately $3.3 million during the first six months of 2019 (January 1 to June 30). According to MECL, the actual RORA balance is calculated on an annual basis and, as such, the $3.3 million is a temporary or notional value that is subject to change. MECL continues to forecast a RORA balance of zero for 2019.

173. At the hearing, MECL explained that it does not forecast to over-earn, and as such, does not forecast any contributions to the RORA account during the rate setting period. However, MECL confirmed that it likewise did not forecast any over-earnings for 2016, 2017 or 2018, yet over-earned by approximately $10 million during that period.

8.1 Proposed RORA Refund

174. In its Application as filed in November 2018, MECL sought approval to refund the balance of the RORA account to ratepayers over the three year period from March 1, 2019 to February 28, 2022. The proposed refund rate was $0.00250 per kWh for each rate class.

175. In its revised schedules and rates filed on July 31, 2019, MECL sought to refund the balance of the RORA account from September 1, 2019 to February 28, 2022 at the rate of $0.002264 per kWh.

176. The proposed RORA refund per kWh is included in the rates proposed by MECL in the current Application.

8.2 Findings

177. The Commission has serious concerns about the substantial level of over-earning by MECL during the last rate setting period. For a company with annual net earnings of approximately $13 million, over-earnings of $10 million are significant and – for a regulated entity operating in a cost of service model – this is not acceptable.

178. Through the interrogatory process, Commission Staff asked MECL to explain the basis of the over-earnings. According to MECL, the excess earnings between 2016 and 2018 were due to higher than forecast sales growth which resulted from the continued adoption of

space heating, recent taxation changes to residential electricity bills, and stronger than expected economic growth.

179. Contrary to MECL's explanation, the evidence shows that the Company's actual sales were lower than forecast in each of 2015, 2016 and 2017 – yet MECL still over-earned in each of these years:

Comparison of Actual to Forecast Sales				
Year	**Forecast sales (GWh)**	**Forecast growth (percent)**	**Actual sales (GWh)**	**Actual growth (percent)**
2015	1,195.3	2.4	1,188.6	1.8
2016	1,193.7	(0.1)	1,188.4	(0.0)
2017	1,218.4	2.1	1,208.1	1.7

180. The lack of an adequate explanation for the substantial over-earnings is of concern to the Commission.

181. Further, MECL is using the balance of the RORA account in such a way that it makes the proposed rate increase appear to be less than it in fact is. As explained by Multeese Consulting, the rate increase sought by MECL is significantly more than 0.7 percent or 1.1 percent. However, the Company relies on the use of the ECAM deferral account and the RORA refund to minimize the proposed rate increase. This is not the purpose of the ECAM or the RORA, and sends improper price signals to customers regarding the true energy supply cost.

182. The $10 million in the RORA account represents the amount by which MECL has over-earned between 2016 and 2018. This amount must be returned to ratepayers without delay.

183. The Commission is not, therefore, prepared to accept MECL's proposal to refund the balance of the RORA account over a three year period. To do so would amount to returning the over-payments to present-day and future ratepayers, rather than to the ratepayers who actually contributed to the excess earnings.

184. As a result, the Commission orders MECL to refund the balance of the post-2015 RORA, together with interest, to ratepayers commencing March 1, 2020. The RORA balance shall be used to minimize the proposed rate increase for the period from March 1, 2020 to February 28, 2021. In the event the balance of the post-2015 RORA account is sufficient to ensure that there is no rate increase effective March 1, 2020, yet there is still a balance remaining in the post-2015 RORA account, the remaining balance shall be refunded to ratepayers during the period from March 1, 2021 to February 28, 2022. To be clear, the refund rates shall be such that the post-2015 RORA account shall be fully refunded to ratepayers, and shall therefore have a zero balance, on or before February 28, 2022.

185. Further, the Commission is not prepared to allow the continuation of the RORA account in its current form. In particular, the RORA account shall no longer be used as a deferral account to collect over-earnings during the three year rate setting period. Instead, any over-earnings earned in 2019, 2020 and/or 2021 shall be determined by the Company as at December 31 of each year, and refunded to ratepayers on a per kWh basis within 60 days of the calendar year-end.

186. The Company shall continue to file the balance of the RORA account with the Commission on a monthly and annual basis. Further, the Company shall file with the Commission, on or before January 31 in each of 2020, 2021 and 2022, the balance of the RORA account as at December 31 in the preceding year, together with the proposed per kWh refund (if any).

9 WEATHER NORMALIZATION MECHANISM

187. As part of the Application, MECL is seeking approval of the Weather Normalization Mechanism and Reserve account for 2019 and future years.

188. The Weather Normalization Mechanism is another deferral account that is, in essence, used to ensure that the Company earns its allowed rate of return in warmer than average years. The mechanism operates by allowing MECL to "reserve" revenue earned in colder-than-average years for use in warmer-than-average years.

189. In a year when heating degree days ("HDD") are higher than normal (i.e. colder temperatures than historical average), a marginal net revenue amount is subtracted from the Company's income statement and added to the Weather Normalization Reserve.

190. In a year when HDD are lower than normal (i.e. warmer temperatures than historical average), a marginal net revenue amount is added to the Company's income statement and subtracted from the Weather Normalization Reserve.

191. The Weather Normalization Mechanism was approved by the Commission for the first time on an interim basis only as part of the 2016 General Rate Application. At that time, the Commission expressed concern about the impact that the Weather Normalization Reserve may have on the RORA account. In particular, the Commission was concerned that contributions to the RORA account – and the associated refund to ratepayers – may be diminished as a result of the Weather Normalization Reserve.

192. Due to these concerns, MECL was ordered to file with the Commission, as part of its monthly reporting requirements, the monthly balance of the Weather Normalization Reserve. MECL was also ordered to file, on or before February 28 in each of 2017, 2018 and 2019, the year-end balance of the Weather Normalization Reserve.

193. The Commission advised MECL that it would determine the appropriateness of continuing a permanent Weather Normalization Reserve based upon review and analysis of the monthly and annual reports.

194. MECL has provided the monthly balance of the Weather Normalization Reserve account from January 1, 2016 to June 30, 2019. Although the balance of the reserve account fluctuates throughout the year, the account showed a balance of $626,551 payable to ratepayers as of June 30, 2019.

9.1 Findings

195. The Commission continues to have concerns about the appropriateness of continuing the Weather Normalization Reserve on a permanent basis. In particular, in light of the nominal account balances from 2016 to present, the Commission questions whether the cost of tracking and administering the deferral account justifies its means.

196. The Commission is not, therefore, prepared to approve the Weather Normalization Mechanism and Reserve account on a permanent basis. However, the Commission does approve the continuation of the Weather Normalization Mechanism and Reserve account

on an interim basis until February 28, 2022. But there shall be no change to the method of calculation of the Weather Normalization Mechanism and Reserve account. The methodology used as the basis for the calculation of the Reserve that has been used since 2016 shall continue.

197. During the rate setting period, MECL shall continue to file the monthly balance of the Weather Normalization Reserve as part of its monthly reporting requirements. The Company shall also file, on or before January 31 in each of 2020, 2021 and 2022, the year-end balance of the Weather Normalization Reserve account.

198. The Commission will continue to monitor the monthly and annual balances of the Weather Normalization Reserve account to determine whether the mechanism should be adopted on a permanent basis.

10 CTGS DECOMMISSIONING

199. In accordance with section 10 of the *Electric Power Act*, MECL requires Commission approval to sell, assign, transfer, lease, mortgage or otherwise dispose of its property outside the ordinary course of business. Section 10 of the *Electric Power Act* provides:

> ***10. Sale or transfer of property without approval prohibited***
>
> *Notwithstanding the provisions of any statute of this province, no public utility, except in the ordinary course of business, shall sell, assign, transfer, lease, mortgage or otherwise dispose of the whole or part of its property used in connection with its operations without first having obtained the approval of the Commission, and no person owning any public utility shall sell, assign, transfer, lease, mortgage or otherwise dispose of the public utility without that approval.*

200. As part of this Application, MECL is seeking Commission approval to decommission the Charlottetown Thermal Generating Station ("CTGS") beginning in 2019. The Company seeks to recover the cost of the decommissioning, estimated to be $14.5 million, from ratepayers. It also seeks to recover the amount of the accumulated reserve variance for CTGS, estimated to be $16.245 million, from ratepayers.

10.1 Proposed Decommissioning Plan

201. On June 28, 2018, the Company filed a CTGS Decommissioning Study (the "Decommissioning Study") as required by Commission **Order UE16-04**. The Decommissioning Study was prepared by GHD.

202. The CTGS site consists of 11.65 hectares (28.8 acres) of land located near the Charlottetown Harbour. MECL has a 999 year lease with the Cumberland Trust for a portion of the property. The Company also has a lease agreement with the Charlottetown Harbour Authority Inc. for a 6.45 hectare water lot.

203. The CTGS site houses numerous pieces of infrastructure that are used for generation and distribution. This infrastructure includes:

1. Combustion turbine no. 3 ("CT3");
2. Energy Control Centre ("ECC");
3. River pumphouse and circulating water infrastructure;

4. Bulk storage tank farm;

5. Numerous petroleum storage tanks (above and below ground) used to store Bunker C fuel, No. 2 diesel fuel, lube oil, waste oil and propane;

6. Six steam boilers that burn heavy fuel oil (Bunker C); and

7. Four steam turbine units.

204. At present, CT3 and the ECC are housed in the Steam Plant Building located at the CTGS site. The original Steam Plant Building was constructed in approximately 1926. The "new" portion of the Steam Plant Building was built at various times throughout the 1950s and 1960s.

205. As part of the decommissioning, MECL proposes to demolish the entire Steam Plant Building. This includes the decommissioning of eighteen (18) petroleum storage tanks. Seven (7) petroleum storage tanks will remain on-site following the decommissioning.

206. Once the Steam Plant Building is demolished, CT3 and the ECC will be relocated to a new balance of plant building ("BOP") that MECL proposes to construct. MECL intends to undertake this work in 2020, and estimates the cost to construct the new BOP to be approximately $3.2 million.

207. In addition to the demolition of the Steam Plant Building and the decommissioning of the petroleum storage tanks, MECL also seeks to decommission:

1. Two concrete smokestacks (ranging in height from 61 meters to 69 meters);

2. River pumphouse and circulating water infrastructure;

3. Bunker C Bulk Storage Tank, Bunker C fuel lines, steam heat pipelines and Bunker C Off-Loading Area; and

4. Thirteen exterior oil-filled transformers.

208. MECL proposes to remediate the site to a degree that is compliant with regulatory requirements and conducive to future energy system expansion and/or development.

209. In accordance with the decommissioning plan, MECL proposes to start the staged shutdown of the remaining steam units at CTGS starting in 2019, and to complete site decommissioning activities by late 2023.

210. As part of this Application, MECL is seeking approval of the decommissioning, which is estimated to cost $11.3 million. In addition to the decommissioning, MECL is seeking approval to construct a new BOP at an estimated cost of $3.2 million. MECL intends to submit the final project details and budget for the new BOP as part of its 2020 Capital Budget. The total cost of MECL's proposed decommissioning plan is therefore estimated to be $14.5 million.

211. MECL also requests that the Commission deem the entire CTGS site to be used and useful following the decommissioning. If the site is deemed to be used and useful, it will remain in MECL's rate base and will entitle MECL to earn a return on the value of the asset.

212. As the CTGS decommissioning is a multi-year project with an expected completion date of 2023, MECL proposes to report to the Commission every six months on costs and project timelines.

10.2 Synapse Report

213. Synapse Energy Economics, Inc. ("Synapse") was retained on behalf of Commission Staff to evaluate the proposed CTGS decommissioning. Synapse filed its initial report with the Commission in March 2019.

214. In its initial report, Synapse agreed with the decision to decommission the steam generation units 7 to 10 at the CTGS. Synapse did not, however, agree with MECL's proposal to demolish the existing Steam Plant Building and construct a new BOP.

215. In particular, Synapse was concerned that MECL had not presented sufficient financial justification for its proposed plan, nor did it provide clear plans for the site that would support the demolition and construction of a new BOP. Without financial justification or a plan for future use, Synapse was not satisfied that MECL's proposed plan was in the best interest of ratepayers.

216. After reviewing the Decommissioning Study and exchanging interrogatories with MECL, Synapse made the following recommendations:

1) The Commission should approve the retirement of Turbines 7 to10.

2) The Commission should not approve the demolition of the non-BOP portion of the CTGS structure until MECL presents a more robust case for the cost-effectiveness of demolition over retention.

3) The Commission should not approve the demolition of the BOP-portion of the CTGS structure and construction of a new BOP building unless MECL can present a clearer justification, since demolition does not appear to be meaningfully less expensive than maintaining the existing BOP.

4) The Commission should deem the entire CTGS site used and useful. However, this designation should be made contingent on MECL filing a long-term plan for energy system utilization for the site in short order.

5) The Commission should institute appropriate safeguards to ensure that MECL continues to minimize costs as the decommissioning process proceeds. As currently construed, there is no incentive for MECL to keep costs below the approved budget for the decommissioning.

6) MECL should be required to make a clearer case for the magnitude of the mobilization/demobilization budget item, substantiating why it believes that it will be necessary to hire a contractor from outside the province.

7) The Commission should ensure that MECL conducts all necessary environmental testing and other necessary follow-up on risk items before commencing the decommissioning, and that it modifies its projected decommissioning budget and workplan as appropriate based on the results of subsequent testing.

8) Synapse recommends that MECL conduct a simple probabilistic analysis in which the probability of occurrence for each environmental risk item is multiplied by the total cost for each associated risk item in order to produce a more accurate assessment of total environmental risk exposure for the decommissioning.

9) If any revisions are made to the proposed workplan and budget, then MECL should be instructed to submit a new budget that not only reflects the modifications to the site decommissioning cost, but also adjusts the value of any other items that are assessed in proportion to the site decommissioning cost, including allowances.

10) The requested increase in depreciation rates should only be granted if MECL can clearly illustrate how the lag in implementation of the previous rate change, adjusted service life assumptions, shift in net salvage, and other factors have contributed to the requested revision to the current rates.

11) Decommissioning costs should not be escalated unless MECL can provide a clear justification for escalation and illustrate that this escalation is consistent with the approach taken in past CTGS-related financial calculations.

217. A copy of Synapse's initial report was provided to MECL. In June 2019, MECL filed a response to the recommendations made by Synapse, which included the filing of additional evidence.

218. Synapse reviewed the responses and additional evidence filed by MECL and submitted its comments in the form of a memorandum dated July 3, 2019. As a result of the additional material filed by MECL, Synapse determined that recommendations 1, 6 and 9 (above) were resolved. All other recommendations were considered unresolved.

219. At the hearing, no representative from GHD or Synapse was called to give evidence. However, MECL's witness, Mr. Angus Orford, provided an overview of the proposed decommissioning and spoke to the unresolved recommendations arising from the Synapse Report.

220. Mr. Orford explained that from MECL's perspective, there is no uncertainty regarding the future use of the CTGS site. Due to its strategic location, MECL intends to retain the site for its future needs. However, no particulars were provided as to the intended use of the site.

221. With respect to the demolition of the Steam Plant Building, MECL explained that it would be more economical to demolish the plant while the specialized equipment is on-site for the decommissioning. Further, MECL does not consider it to be financially responsible to retain the Steam Plant without a known, viable repurposing option. According to MECL, the estimated cost to maintain the existing Steam Plant is $1.433 million more than building a new, smaller BOP.

10.3 Forecast Generating Capacity Deficiencies

222. Although not specifically addressed by MECL in this Application, the Commission feels it is prudent to comment on forecast generating capacity deficiencies due, in part, to the decommissioning of the CTGS.

223. The CTGS currently provides 55 MW of on-Island generating capacity. As the decommissioning progresses between 2019 and 2021, the amount of generating capacity will be gradually reduced. Under MECL's proposal, by 2022 CTGS will be fully decommissioned. As a result, there will be no generating capacity from the CTGS after 2021.

224. MECL currently has no plans to replace the CTGS generating capacity with on-Island generation.

225. This is of particular concern to the Commission. As of November 2018, MECL anticipated being capacity deficient by 1 MW in 2020. This capacity deficiency will only increase once the CTGS is fully decommissioned.

226. To deal with anticipated capacity short-falls, MECL proposes to purchase additional short-term capacity from New Brunswick. MECL forecasts that short-term capacity purchases will increase by approximately 80 percent between 2018 and 2021.

227. By 2022, after the CTGS is fully decommissioned, MECL will procure 53 percent of its capacity via short-term capacity purchases, and will be obtaining 60 percent of its generating capacity from off-Island sources through a single transmission corridor.

228. In response to interrogatories from Commission Staff, MECL advised that it has sufficient planning capacity reserves up to 2027, when the Mactaquac Generation Station goes offline. However, its primary concern is the continued reliability of NB Power's transmission system. MECL believes that having two-thirds operating capacity supply exposed to periodic transmission limitations in New Brunswick is a potential future risk. MECL is also uncertain that the on-Island 138 kV transmission system can maintain system stability and support voltage above the current 300 MW import level.

229. Due to these concerns and anticipated future limitations, MECL intends to undertake the following investigations:

1. A detailed study of the Island transmission system to determine its capabilities under high import situations;
2. The use of transmission, generation and peak load management techniques in order to accommodate the growing peak load and potential high imports; and
3. Whether additional on-Island generation is the optimal solution.

10.4 Findings

230. For the reasons that follow, the Commission is not satisfied that the demolition of the existing Steam Plant Building and the construction of a new BOP is a reasonable course of action at this time. As such, these aspects of the decommissioning plan are not approved by the Commission at this time. The Commission approves all other aspects of the decommissioning plan as proposed by GHD.

231. Although MECL has indicated that it intends to retain the entire CTGS site for future needs, the Company has not presented any evidence as to how it intends to use the CTGS site in the future. Without a clear plan for future use, the Commission cannot determine whether MECL's proposed demolition and construction of a new BOP is economical or in the best interests of ratepayers. As explained by Synapse:

> *...Without more detail about future site utilization plans, the utility and its ratepayers risk doing too little, too much, or simply taking the wrong tack in this decommissioning.*

232. As such, the Commission does not approve the demolition of the existing Steam Plant Building, nor does it approve the construction of a new BOP at this time. It is open to MECL to seek Commission approval once a clear plan for future use of the CTGS site has been established.

233. The Commission also has concerns about the designation of the entire CTGS site as being used and useful. Without a long-term plan for the site, there is no way to determine

whether all or part of the CTGS site will be used and useful in the production, transmission, distribution and furnishing of electric energy.

234. As part of this Order, the Commission is prepared to designate the entire CTGS site as being used and useful, pending receipt of a long-term plan for energy system utilization for the site. The plan shall be filed with the Commission on or before **September 30, 2020**. Upon receipt and review of the long-term plan, the Commission will then determine whether or all part of the CTGS site should continue to be classified as used and useful.

235. Further, the Commission orders MECL to complete all necessary environmental testing and other necessary follow-up on risk items before commencing the decommissioning. If necessary, MECL shall modify its budgeting and workplan based on the results of the testing and shall file a copy of the revised budget and workplan with the Commission prior to commencing the decommissioning.

236. As the decommissioning progresses, MECL shall be required to file written reports with the Commission every six months from the date of commencement. The reports shall provide updates on costs, project timelines, and any variations from the approved budget. Further, in the event the cost of the decommissioning varies by plus or minus $500,000.00, MECL shall be required to apply to the Commission for approval of the variance.

237. Finally, MECL shall be required to undertake the following investigations and file the results, together with any recommendations, with the Commission on or before **September 30, 2020**:

1. A detailed study of the Island transmission system to determine its capabilities under high import situations;
2. The use of transmission, generation and peak load management techniques in order to accommodate the growing peak load and potential high imports; and
3. Whether additional on-Island generation is the optimal solution.

11 AMORTIZATION RATES

238. MECL, as a regulated utility, is required to carry a "proper and adequate" depreciation account. The Commission is required to determine the proper and adequate rates of depreciation, in accordance with section 23 of the *Electric Power Act*, which provides:

> ***23. Depreciation accounts, utilities must carry***
>
> *Every public utility shall carry a proper and adequate depreciation account when the Commission, after investigation, determines that the depreciation account can be reasonably required; the Commission shall ascertain and determine what are proper and adequate rates of depreciation of the several classes of property of each public utility.*

239. The application of section 23 of the *Electric Power Act* has been suspended by legislation at various times over the past 25 years. In particular, section 23 was suspended while the price cap was in effect (April 1994 to December 2003) and while the Energy Accord was in effect (March 2011 to February 2016). As a result, the Commission did not have the legislative authority and was not permitted to regulate MECL's depreciation account or depreciation rates from 1994 to 2003, or from 2011 to 2016.

240. Notwithstanding the suspension of section 23, the Provincial Government went further and enacted legislation that deemed the Commission to have exercised its authority under section 23, and determined MECL's depreciation account and rates to be "proper and adequate" during the periods of deregulation. It is important to note that during the periods of deregulation, the Commission had no involvement and, moreover, no authority to assess or determine the proper and adequate depreciation rates. The Provincial Government, having taken away this regulatory authority from the Commission. It is also important to note that the result of this action by Government was that depreciation continued at the rate set and no assessment was made of whether the depreciation rates were proper and adequate.

241. Recognizing the end of the Energy Accord in February 2016, MECL engaged Gannett Fleming to prepare a depreciation study. The depreciation study was based on the Company's financial results and assets in service up to and including December 31, 2014 (the "2014 Depreciation Study").

242. As part of the 2016 General Rate Application, MECL sought to adopt the depreciation rates recommended in the 2014 Depreciation Study. The proposed changes to the depreciation rates were expected to result in an increase of approximately $1.981 million in annual depreciation expense. MECL also sought Commission approval to amortize the accumulated reserve variance associated with the CTGS, and to defer amortization of the accumulated reserve variance with respect to all other asset classes. According to MECL, the proposed changes to the depreciation rates would serve to prevent further increases in the accumulated reserve variance, assuming status quo in other variables.

243. The Commission found that the depreciation rates in the 2014 Depreciation Study were proper and adequate. It also found that it was reasonable to defer the amortization of the accumulated reserve variance with respect to all other asset classes so as to balance the rate impact to customers. As a result, the Commission ordered that MECL adopt the depreciation rates set forth in the 2014 Depreciation Study and incorporate into the depreciation rates the recommended amortization of the accumulated reserve variance associated with the CTGS (see **Order UE16-04R**).

244. As part of the 2016 General Rate Application, MECL was also ordered to file an updated depreciation study based on financial results up to December 31, 2017.

11.1 2017 Depreciation Study

245. MECL filed the updated depreciation study with the Commission on June 29, 2018. The depreciation study was prepared by Gannett Fleming and based on financial results up to December 31, 2017 (the "2017 Depreciation Study").

246. The 2017 Depreciation Study is based on the Company's assets in service at December 31, 2017, and uses the straight line method for calculating depreciation using the average service life methodology. The recommended annual depreciation rates incorporate the recovery of the original cost of the assets over their average remaining service life, along with a prudent allowance for the costs to remove the assets upon retirement.

247. The depreciation rates recommended in the 2017 Depreciation Study are summarized below, along with the depreciation rates last approved by the Commission in **Order UE16-04**:

Schedule 11-2		
Existing and Recommended Depreciation Rates by Asset Class		
Asset Class	**Existing Rate (percent)**	**2017 Study Rate (percent)**
Production Plant		
▪ Charlottetown Thermal Generating Station	4.53	5.09
▪ Borden Generating Station	4.81	4.12
▪ Combustion Turbine #3	2.28	2.34
Transmission Plant	2.27	2.45
Distribution Plant	3.32	3.41
General Plant	5.96	5.81
Composite Rate	3.41	3.51

248. The 2017 Depreciation Study also recommends further adjustments to depreciation rates to incorporate the amortization of the accumulated reserve variance. The accumulated reserve variance represents the difference between the recorded accumulated depreciation and the theoretical reserve calculated by Gannett Fleming.

249. At December 31, 2017, Gannett Fleming has calculated the accumulated reserve variance to be $43.973 million and recommends that this balance be amortized over the remaining estimated service lives of the related assets.

250. Further detailed analysis of the Gannett Fleming recommendations with respect to the accumulated reserve variance are contained in Part VI, Table 2 of the 2017 Depreciation Study, and are summarized in **Schedule 11-3** (reproduced below):

Schedule 11-3		
Accumulated Reserve Variance ($ Millions)		
Asset Class	**Balance December 31, 2017**	**Recommended Annual Amortization**
Production Plant		
▪ Charlottetown Thermal Generating Station	18.007	4.842
▪ Borden Generating Station	3.044	0.235
▪ Combustion Turbine #3	1.834	0.054
Transmission Plant	(2.129)	(0.049)
Distribution Plant	22.931	1.090
General Plant	0.286	0.083
Total	**43.973**	**6.255**

251. **Schedule 11-4** (reproduced below) shows the combined impact of the annual depreciation expense and the reserve variance amortization recommended by Gannett Fleming in the 2017 Depreciation Study:

Schedule 11-4				
Gannett Fleming Recommended Annual Depreciation and Reserve Variance Amortization				
Asset Class	**Annual Depreciation ($ Millions)**	**Reserve Variance Amortization ($ Millions)**	**Total Annual Depreciation ($ Millions)**	**Annual Depreciation Rate (percent)**
Production Plant				
▪ Charlottetown Thermal Generating Station	3.090	4.842	7.932	13.06
▪ Borden Generating Station	0.563	0.235	0.798	5.83
▪ Combustion Turbine #3	0.825	0.054	0.879	2.49
Transmission Plant	3.048	(0.049)	2.999	2.42
Distribution Plant	11.891	1.090	12.981	3.72
General Plant	2.586	0.083	2.699	6.00
Total	**22.003**	6.255	28.258	4.51

252. The financial impact of the 2017 Depreciation Study's recommendations, if fully adopted, can therefore be broken down into two main components:

1. The impact of recommended changes in depreciation rates, prospectively, to depreciate assets over the projected average service life remaining; and

2. The impact of the recommended amortization of the calculated accumulated reserve variance as at December 31, 2017.

11.2 Proposed Depreciation Rates

253. MECL does not propose to adopt all of the recommendations made by its expert Gannett Fleming in the 2017 Depreciation Study. The Company notes that adopting all of the recommendations made by Gannett Fleming will result in a significant increase in depreciation expense to be recovered from customers. Instead, MECL makes the following proposal and recommendations:

Depreciation Rates

254. MECL seeks to adopt the depreciation rates recommended in the 2017 Depreciation Study. MECL proposes that the depreciation rates be calculated and adopted as of January 1, 2019.

255. According to MECL, the proposed changes in the depreciation rates will result in an increase of approximately $0.709 million in annual depreciation expense based on 2017 asset values. This increase corresponds to a one-time estimated annual increase in the Company's revenue requirement of approximately 0.36 percent, based on a total estimated revenue requirement of $195 million.

Accumulated Reserve Variance – CTGS

256. MECL seeks approval to establish a regulatory deferral account with respect to the accumulated reserve variance associated with the CTGS ($16.245 million). According to MECL, this will "*provide flexibility to the Utility and the Commission in managing the impact on customer electricity costs*".

257. As explained by the Company, the amounts to be amortized are based on the 2017 Depreciation Study, which incorporates a Class B cost estimate with respect to the proposed CTGS decommissioning. The Class B estimate includes many assumptions with respect to timelines, cost categories and salvage proceeds. In addition, Gannett Fleming has escalated the GHD estimate to 2022 using an assumed annual two percent escalator. Changes in any of these variables could have a net positive or negative impact on the final costs to be recovered.

Accumulated Reserve Variance – All Other Asset Classes

258. Similar to 2016, MECL proposes to again defer recovery of the accumulated reserve variance with respect to all other asset classes. The accumulated reserve variance for all other asset classes (excluding CTGS) is $27.728 million as at December 31, 2017.

Further Studies

259. MECL proposes to undertake a new depreciation study based on financial results up to December 31, 2020 (the "2020 Depreciation Study"). The 2020 Depreciation Study would be filed with the Commission by June 30, 2021. The findings from the Study would be used to update the Commission on the recovery of amounts related to the CTGS and other assets. It would also be used to develop recommendations on the establishment of new depreciation rates as well as the amortization of the calculated accumulated reserve variance for the various asset classes.

11.3 Findings

260. The Commission accepts that the depreciation rates proposed in the 2017 Depreciation Study are proper and adequate. In particular, the proposed depreciation rates are intended to address the remaining book value of the assets over their remaining useful life, which is appropriate.

261. Further, the adoption of the depreciation rates will result in an increase of approximately $0.709 million in annual depreciation expense, based on 2017 asset values. This will not have a significant impact on electric rates. The Commission therefore approves the adoption of the depreciation rates set forth in the 2017 Depreciation Study as being proper and adequate rates of depreciation.

262. The accumulated reserve variance represents the difference between the recorded accumulated depreciation and the theoretical reserve calculated by Gannett Fleming. This variance was calculated to be $43.973 million as at December 31, 2017.

263. The accumulated reserve variance, in essence, represents the value by which MECL's assets were under depreciated as of December 31, 2017. The fact that MECL's assets are under depreciated – and that MECL seeks to recover the full amount of the depreciation expense from ratepayers – is of particular concern to the Commission.

264. The under depreciation of assets has a financial benefit for the Company. The under depreciation of assets means that the assets are over-valued. As the assets form part of

the Company's rate base, the over-valuation of assets results in an over-valuation of rate base. The under depreciation of assets, therefore, allows the Company to earn a rate of return on an over-valued rate base.

265. MECL, through the interrogatory process, was asked to explain why it seeks to continue deferring the amortization of the accumulated reserve variance. MECL explained that it is trying to maintain a reasonable balance between the rate impact on customers and the need to have appropriate depreciation rates. This is an appropriate consideration on the part of MECL.

266. However, MECL has advised that adopting all of the recommendations in the 2017 Depreciation Study, including amortization of the entire accumulated reserve variance, would result in a one-time increase to customer rates of 0.81 percent. The Company also estimates a corresponding reduction in annual earnings of 0.46 percent to 0.47 percent in 2020 and 2021.

267. The Commission is not satisfied that there is sufficient reason to defer the amortization of the accumulated reserve variance for the Company's assets. The proposed deferral is contrary to the recommendations of the expert and is not in accordance with accepted accounting principles, nor is it in the best interest of future ratepayers to whom these expenses are ultimately being deferred.

268. Further, the Commission is concerned about the corresponding over-valuation of the Company's rate base, which has allowed it to earn a rate of return which is greater than the return it would have earned on properly depreciated assets.

269. For all of these reasons, the Commission is not prepared to accept the Company's proposal to defer the amortization of all or part of the accumulated reserve variance, and MECL will follow the advice of the experts, Gannett Fleming.

270. The Commission, therefore, orders MECL to adopt all of the recommendations made by Gannett Fleming in the 2017 Depreciation Study. This includes the adoption of the proposed depreciation rates and the amortization of the accumulated reserve variance for all assets. The depreciation rates and amortization of the accumulated reserve variance shall be adopted as of January 1, 2020, and shall be included in the Company's revenue requirement for rates effective March 1, 2020 and March 1, 2021.

271. As proposed, MECL is ordered to undertake a new depreciation study based on financial results up to December 31, 2020. The 2020 Depreciation Study shall be filed with the Commission no later than **June 30, 2021**.

12 COST ALLOCATION & RATE DESIGN

272. In accordance with the preamble to the *Electric Power Act*, rates, tolls and charges for electric power should be reasonable, publicly justifiable and non-discriminatory. The preamble states in part:

> *WHEREAS the rates, tolls and charges for electric power should be reasonable, publicly justifiable, and non-discriminatory;*

273. The Commission has, on a number of occasions, expressed concern about MECL's rate structure and revenue-to-cost ratios. As MECL is subject to cost of service regulation, the Commission has expressed particular concern about two issues that impact rates and rate design:

1. The first is the continued existence of the residential "second block", which offers a reduced rate per kWh for Residential customers who consume in excess of 2,000 kWh per month.

2. The second is disproportionate revenue-to-cost ratios which, in simplified terms, suggest that certain rate classes are paying more than the cost to serve that class, while other rate classes are paying less than the cost of service.

274. These concerns have been discussed at length by the Commission, most recently in its decision with respect to the 2016 General Rate Application (see **Order UE16-04R**).

275. As part of its initial application in the 2016 General Rate Application, MECL filed a cost allocation study prepared by Chymko Consulting Ltd. The cost allocation study was based on the Company's statement of earnings for the twelve months ending December 31, 2014 (the "2014 Cost Allocation Study").

276. The cost of providing service to the various classes of customers is measured by using a revenue-to-cost ("RTC") ratio. A RTC ratio below 100 percent indicates that the revenue collected from that rate class is less than the cost to serve that class. As a result, a RTC ratio below 100 percent means that the rate class is paying less than MECL's actual cost to serve that class of customers.

277. A RTC ratio above 100 percent indicates that the revenue collected from that rate class is more than the cost to serve that class. As a result, a RTC ratio above 100 percent means that the rate class is paying more than MECL's actual cost to serve that class of customers.

278. Ideally, each rate class would have a RTC ratio of 100 percent, or unity. That is not, however, realistic. Instead, MECL views a RTC range of 90 percent to 110 percent as an acceptable range for the Company's rate classes.

279. However, the 2014 Cost Allocation Study (like cost allocation studies in the past) confirmed the existence of disproportionate RTC ratios in MECL's rate structure. While the RTC ratio for the Residential rate classes (excluding seasonal and farm customers) was 92 percent, the RTC ratio for the General Service rate class was in excess of 110 percent. In simplified terms, the RTC ratios suggest that General Service customers are subsidizing Residential customers.

280. The existence of the residential second block declining rate likely contributes to the disproportionate RTC ratio for the Residential rate class. The declining block rate also encourages energy consumption and sends improper price signals to Residential customers.

281. In the 2016 General Rate Application, MECL initially proposed to increase the residential second block from 2,000 kWh per month to 3,000 kWh effective March 1, 2016, then to 3,800 kWh effective March 1, 2017, and finally to 5,000 kWh effective March 1, 2018.

282. According to MECL's evidence at that time, a 5,000 kWh per month threshold was an appropriate threshold to capture the large majority of the highest consuming Residential customers (with dwellings). MECL proposed to use the estimated $773,000 of incremental revenue generated by this change to the residential second block to lower the electricity costs for General Service customers.

283. Subsequent to its initial filing in the 2016 General Rate Application, MECL entered into the 2016 Rate Agreement with the Provincial Government, and filed an amended application with the Commission.

284. In the amended application, MECL sought to defer any changes to the residential second block. Instead, MECL proposed to consult with stakeholders and undertake a rate design study to determine the appropriate class for all or some farms, and to file an updated cost allocation study using 2017 financial data.

285. The deferral of changes to the residential second block was supported by the Provincial Government. As part of the 2016 General Rate Application, the Government presented evidence that it was developing a new Provincial Energy Strategy, the results of which could lead to new policy direction on electricity supply and/or usage.

286. The Government also submitted that changes to the second block rate could have a significant financial impact on certain customers, but it did not provide any evidence in support of this position. It submitted that consultation should occur with affected customers prior to implementing any changes, and suggested that there may be opportunities to mitigate the financial burden through programs resulting from the Provincial Energy Strategy and demand side management.

287. The Commission ultimately allowed the deferral of changes to the residential second block to allow for consultation with impacted customers and to explore opportunities to mitigate the financial burden. However, the Commission stated, unequivocally, that the continued existence of the second block is contrary to the principles behind the *Electric Power Act*. As a result, the Commission put MECL and the Provincial Government on notice that "*any proposed continuation of the residential second block rate in future rate applications will require compelling evidence of its equity to ratepayers*" (see **Order UE16-04R**).

288. In the 2016 General Rate Application, MECL was ordered:

1. To undertake a rate design study to consider changes to the multi-block residential energy pricing structure, and related changes to MECL's other rate structures. MECL was ordered to file the rate design study and a proposed rate structure with the Commission on or before April 30, 2018;
2. To file an updated cost allocation study with the Commission on or before June 30, 2018, based on the Company's financial results to December 31, 2017; and
3. To prepare and file with the Commission a Point Lepreau cost allocation classification study on or before April 30, 2017.

289. As ordered, MECL filed an application seeking changes to the classification of costs related to Point Lepreau. The application was filed on April 27, 2017. In addition to the classification of costs related to Point Lepreau, MECL sought changes to the classification of costs related to on-Island generation fuel and wind power purchases (the "Point Lepreau Cost Allocation Classification Study").

290. Also as ordered, MECL filed an updated cost allocation study prepared by Chymko Consulting Ltd. (the "2017 Cost Allocation Study"). The 2017 Cost Allocation Study was filed on June 29, 2018.

291. MECL did not, however, file a rate design study as ordered by the Commission in **Order UE16-04**. The rate design study was to be filed with the Commission on or before April 30, 2018, for consideration as part of the current Application.

292. In April 2018, MECL requested an extension of the deadline to file the rate design study. According to the Company, additional time was required to complete the 2017 Cost Allocation Study and to undertake a farm rate study, both of which could impact the

development of rate design proposals. MECL requested an order from the Commission deferring the filing of the rate design study until the earlier of October 31, 2018, or the date upon which the Company filed the current Application. MECL's request was granted by the Commission in **Order UE18-02**, dated April 17, 2018.

293. Contrary to the orders of this Commission, MECL did not file a rate design study on or before October 31, 2018. The Commission fully expected that the rate design study would be filed in the present Application. However, the rate design study was not included with the present Application, which was filed on November 30, 2018.

294. To date, notwithstanding two outstanding orders of the Commission, no rate design study has been filed by MECL.

12.1 Proposed Cost Allocation & Rate Design

Point Lepreau Cost Allocation Classification Study

295. In the present Application, MECL seeks approval of the classification of power supply costs recommended in the Point Lepreau Cost Allocation Classification Study. The classifications, if approved, will be used for future cost allocation studies.

296. The classifications recommended in the Point Lepreau Cost Allocation Classification Study are summarized as follows:

1. **Point Lepreau Fixed Costs**:

297. The Point Lepreau fixed costs are currently classified as 95 percent Demand related and 5 percent Energy related. MECL seeks to re-classify the Point Lepreau fixed costs as 25 percent Demand related and 75 percent Energy related. According to MECL, the proposed classification reflects the fact that most of the fixed costs for a nuclear generating plant are incurred to provide base load energy.

2. **On-Island Oil-Fired Units**:

298. The generation fuel costs at the Company's oil-fired plants are currently classified as fixed costs, and therefore 100 percent Demand related. MECL seeks to re-classify all combustion turbine fuel costs as Energy related.

299. According to MECL, this change reflects the fact that most fuel usage by the Company's combustion turbines occurs to supply energy for the system. Fuel costs for the CTGS will continue to be classified as Demand related because most fuel usage at the CTGS occurs for equipment testing, operator training and plant heating.

3. **Wind Power Purchase Costs**:

300. Wind power purchase costs are currently classified as 100 percent Energy related. MECL seeks to re-classify wind power purchase costs as Demand related in the same proportion that wind power nameplate capacity is counted as capacity for generating capacity planning purposes. Currently this proportion is 23 percent.

2017 Cost Allocation Study

301. The 2017 Cost Allocation Study was prepared by Chymko Consulting Ltd. ("Chymko") and is based on financial results for the twelve months ending December 31, 2017. According

to MECL, the 2017 Cost Allocation Study consists of a technical update of the 2014 Cost Allocation Study which was also prepared by Chymko.

302. **Schedule 13-7** (reproduced below) provides a comparison of the RTC ratios from the 2017 Cost Allocation Study versus the 2014 Cost Allocation Study:

Schedule 13-7 2017 Collected Revenue and Allocated Costs and Revenue to Cost Ratios (percent)				
	Revenue Collected	**Allocated Cost**	**Revenue to Cost Ratio 2017**	**2014 CA Study**
Residential	45.9	50.3	91	92
Residential (S)	2.4	2.5	96	97
Residential Farm	3.8	4.6	82	81
General Service I	31.9	26.2	122	117
General Service I (S)	1.0	0.9	113	115
Small Industrial	6.4	6.2	102	96
Large Industrial	7.2	7.7	94	100
Lights	1.3	1.4	91	103
Unmetered	0.2	0.2	104	103
Total	**100.0**	**100.0**	**100.0**	**100.0**

303. MECL draws a number of conclusions from the results of the 2017 Cost Allocation Study. These conclusions are as follows:

1. The RTC ratio results from the 2017 Cost Allocation Study are reasonably consistent with the results of the 2014 Cost Allocation Study.

2. The Residential rate class continues to reflect a RTC ratio below 100 percent indicating that revenue is lower than allocated costs in this rate class.

3. The General Service rate class continues to reflect a RTC ratio above 100 percent indicating that revenue is higher than allocated costs within the General Service class.

4. Similar to the 2014 Cost Allocation Study, farms which are currently part of the Residential rate class, were segregated from other residential customers to determine a specific RTC ratio for farm customers. The RTC ratio for farms continues to be below 100 percent indicating that revenue is lower than allocated costs for this group of customers.

5. The Large Industrial rate class RTC ratio is below 100 percent in the 2017 CAS as compared to the 2014 study result of 100 percent. This indicates that revenue is less than allocated costs for this rate class.

6. The Lighting rate class RTC ratio result of 91 percent shows a decrease in the RTC compared to the results of the previous study. This is substantially attributable to the LED streetlight conversion program which has resulted in increased capital costs from new light addition and reduced energy sales in the class.

Rate Design

304. MECL did not file a rate design study as ordered by the Commission. Instead, as part of its Application, MECL provided its own "analysis and recommendations" arising from the results of the 2017 Cost Allocation Study.

305. MECL is proposing two changes to the Residential rate class as a result of the 2017 Cost Allocation Study. These changes relate to the monthly service charge for Rural Residential customers and the proposed phasing-out of the residential second block. The particulars of each proposed change are as follows:

1. **Reduction in the Rural Service Charge**:

306. Currently, the Company charges different monthly service charges for Urban Residential customers (currently $24.57) and Rural Residential customers (currently $26.92).

307. MECL is proposing to charge the same monthly service charge for all year round Residential customers ($24.57). This is expected to result in an overall reduction in total revenue in the amount of $990,000 from the Residential rate class.

2. **Phasing-out of the Residential Second Block**:

308. MECL proposes to increase the residential second block threshold from 2,000 kWh to 5,000 kWh effective March 1, 2021. The Company proposes to eliminate the second block effective March 1, 2022, which is outside the current rate setting period.

309. In support of its proposal to phase-out, and eventually eliminate, the residential second block, MECL states that:

- PEI is the only remaining province in Canada where a residential declining block rate exists;
- The declining block rate inappropriately communicates that the cost of energy decreases with each kWh consumed. This is not consistent with the Company's energy supply contract pricing nor its use of available generating equipment; and
- In an age where energy conservation is being promoted by utilities and customers, the declining block rate sends the wrong price signal to customers.

310. Also of note is what MECL is *not* proposing to change as part of the present Application.

311. MECL is recommending that all farms remain in the Residential rate class during the rate setting period. This will allow farms to continue to benefit from the residential second block rate. MECL explained that although it intended to include recommendations as to the appropriate rate classification for farms as part of the Application, the necessary meters were not installed until March 2018. MECL submitted that it requires at least one year of customer data (preferably two) before making recommendations.

312. At the hearing, MECL witnesses advised that in 2018, meters were installed at 88 large farms that are currently in the Residential rate class. July 2018 was the first month of complete hourly data from all 88 meters. The analysis of the data has begun and the Company expects to have a preliminary report prepared by the end of 2019. A final report, based on two full years of data, will be completed in late 2020.

313. MECL is also recommending that any changes to the General Service rate class be deferred pending completion of the farm rate study and load research study. The 2017 Cost Allocation Study shows that the RTC ratio for the General Service rate class is 122 percent. This means that General Service customers are paying 22 percent more than the cost of service. This is well outside the Company's proposed target RTC range of 90 percent to 110 percent.

314. According to MECL, the results of the farm rate study and load research study could impact the costs and revenues allocated to the General Service rate class, which would impact the resulting RTC ratio.

315. At the hearing, MECL provided an update on the Company's load study of Residential and General Service customers. The load study involves the installation of approximately 550 meters that record hourly load data. One-third of the meters will be installed for a randomly selected group of Residential customers, and two-thirds will be installed for a randomly selected group of General Service customers. Approximately 150 meters have been installed to date, with the balance expected to be installed by year-end. The objectives of the load study are to provide better estimates of the coincident and non-coincident peak loads of the Residential and General Service rate classes. These estimates will then be incorporated into future cost allocation studies.

316. At the hearing, Mr. John Gaudet, President of MECL, admitted that the Company was "*behind a couple of years in its load research*". This was due to delays on the part of MECL, and delays on the part of equipment manufacturers. As MECL submits that it does not have sufficient data at this time, they are generally recommending the status quo with respect to the current rate structure.

12.2 Multeese Report

317. Commission Staff retained Multeese Consulting Incorporated ("Multeese"), and its principal, Mel Whalen, P. Eng., to provide expert evidence in relation to the Point Lepreau Cost Allocation Classification Study, the 2017 Cost Allocation Study, and matters of rate design.

318. Multeese filed an expert report with the Commission in May 2019. Mr. Whalen also testified as an expert witness at the hearing of the Application.

319. Multeese concluded that the recommendations made in the Point Lepreau Cost Allocation Classification Study are reasonable and should be approved by the Commission.

320. Multeese also concluded that the 2017 Cost Allocation Study represents a reasonably accurate picture of how the Company's revenues provided by individual rate classes compares to the cost of providing service to those rate classes in 2017. However, Multeese recommends that the cost allocation study methodology used by MECL change from a historical year basis to a future year basis. In doing so, the RTC ratios will be based in the years for which rate changes are being proposed.

321. Although Multeese is generally supportive of the Point Lepreau Cost Allocation Classification Study and the 2017 Cost Allocation Study, Multeese does not agree with MECL's proposal to defer changes to the residential second block and the General Service rate class.

322. With respect to the General Service rate class, Multeese concludes that the RTC ratio is significantly above MECL's chosen target range of 90 percent to 110 percent. As General Service customers are already paying more than the cost of service, Multeese

recommends that the rate increase for the General Service rate class be reduced to 50 percent of MECL's proposed average increase.

323. Multeese also recommends an alternate approach to phase-out and eliminate the residential second block during the rate setting period.

324. In the Application as filed, MECL proposes to leave the second block threshold at 2,000 kWh in 2019 and 2020. The threshold would then increase to 5,000 kWh effective March 1, 2021, and the second block would be eliminated effective March 1, 2022, which is outside the rate setting period.

325. Multeese recommends that the residential second block be phased-out over a three year period, such that the first and second block energy price are equal by March 1, 2021. In doing so, Multeese does not recommend increasing the kWh threshold for the second block. Instead, Multeese recommends incremental increases to the basic rate for the second block in 2019, 2020 and 2021, such that by 2021, the first and second block energy price will be equal.

326. The below table shows the impact of the Multeese proposal to phase-out second block over a three year period. The table shows the percentage increase (or decrease) in a Residential customer's monthly electricity bill in each of the next three years, depending on the customer's monthly consumption. The final row of the table identifies the cumulative impact of phasing out the residential second block over a three year period, as proposed by Multeese:

Consumption (kWh /mo.)	2500	3500	4500	7500	12000
2019 vs 2018	-0.23%	1.56%	2.65%	4.30%	5.30%
2020 vs 2019	2.20%	3.28%	3.91%	4.85%	5.41%
2021 vs 2020	3.81%	6.82%	8.57%	11.11%	12.59%
2021 vs 2018	5.85%	12.05%	15.81%	21.51%	24.96%

327. The cumulative impact of the Multeese proposal therefore ranges from 5.85 percent to 24.96 percent depending on the customer's energy consumption. Multeese notes that although the greatest impact is on customers who consume more than 3,500 kWh per month, this represents only 1.23 percent of Residential customers (825 customers).

328. Multeese explained that the rate impact of eliminating the residential second block is the same regardless of how it is phased-out; a Residential customer who consumes 12,000 kWh per month will ultimately see a 24.96 percent rate increase once the residential second block is eliminated. However, Multeese recommends a gradual phasing-out over three years (rather than two years as proposed by MECL) to lessen the rate increase in any one year.

329. Multeese also comments on MECL's approach of deferring changes to the General Service class and the residential second block pending completion of the load study and farm classification study. According to Multeese, this approach is not necessarily unreasonable. However, it is unlikely that these studies will provide a clear path to resolving either the General Service RTC ratio issue or the residential second block issue.

As a result, Multeese recommends dealing with these issues as part of the current Application, rather than deferring them.

330. Multeese also comments on MECL's chosen target RTC range of 90 percent to 110 percent. Multeese recommends that although a RTC range of 90 to 110 is a reasonable short to medium term objective, moving the RTC ratios within 95 to 105 is an appropriate longer term objective.

331. MECL filed a brief response to the Multeese Report on May 31, 2019. In its response, MECL does not take issue with Multeese's recommendation to reduce the rate increase for the General Service rate class, nor does it take issue with Multeese's recommendations on the appropriate RTC target range. However, MECL expresses concern about the proposed manner of eliminating the residential second block and the proposed changes to the cost allocation study methodology.

332. In its response, MECL proposes an alternate approach to phase-out second block which, according to MECL, places less of an immediate financial burden on farm customers in the Residential rate class. At the hearing, MECL explained that it did not agree with the Multeese proposal to increase the second block energy charge. Instead, it preferred to increase the second block threshold as this "*would have a smaller impact on the electric bills of large farms*".

333. MECL also explained that it does not support the proposed change to the cost allocation study methodology from historic year(s) to future year(s). According to MECL, the cost and time to develop such an analysis would provide little to no additional value relative to the current approach.

12.3 Submissions of Interveners & Members of the Public

334. The Commission invited interested members of the public to submit comments on the Application. The Commission received a number of written comments relating specifically to the residential second block. While some individuals advocated against the elimination of the residential second block due to the impact on their electricity bills, others advocated for the elimination of the second block.

335. Those who supported the elimination of the second block rate noted a number of issues with the current rate structure, including the subsidization of large electrical consumers, improper pricing signals, and the incentive to increase (rather than decrease) electricity consumption.

336. The Commission also had the benefit of submissions from the PEI Energy Corporation, Mr. Stephen Howard, and Mr. Roger King, each of whom represented different interests and presented alternate ways to approach matters of rate design and the elimination of the residential second block.

337. The PEI Energy Corporation was generally supportive of MECL's Application, including the proposed rate increases and the proposed manner of phasing-out the residential second block. At the hearing, Ms. Kim Horrelt, P. Eng., on behalf of the PEI Energy Corporation, explained that the Energy Corporation is actively working with Islanders who would be impacted by the elimination of the second block to help mitigate potential "rate shock".

338. In particular, Ms. Horrelt explained that the Provincial Government has tabled amendments to the *Renewable Energy Act* that are intended to encourage solar installation in the agriculture sector. The Province has also recently introduced a new Solar

Rebate Program. Although these programs may help to alleviate the financial impact of eliminating the residential second block, the implementation and uptake of these programs will take time.

339. Mr. Roger King expressed concern with the overly narrow focus on the elimination of the residential second block. Mr. King advocated for a comprehensive review of MECL's existing rate structure, and presented an option that would segment customers into smaller and different customer tariffs using new pricing signals.

340. Mr. King also emphasized that customer rate classes should be based on energy use, rather than energy application. He noted, for example, that there is no immediate need to separate the majority of farm customers from high-use residential customers.

341. With respect to MECL's proposal to increase the second block threshold to 5,000 kWh, Mr. King noted that this actually worsens the inequity between customers. The proposal would have the greatest impact on Residential customers who consume between 2,000 kWh and 5,000 kWh per month, and would have a much less significant impact on the highest Residential consumers, such as large farms.

342. Mr. King also expressed concern about the rapidly growing peak load demand. According to Mr. King, approximately 50 percent of MECL's annual capital budget is driven by annual growth in peak load. He explained that peak load demand will be a future challenge for MECL's existing infrastructure. Mr. King recommended the use of time-of-day metering and rate structures with demand charges to encourage customers to change energy use habits, thereby helping to manage peak load.

343. Mr. Stephen Howard, MLA and Opposition Shadow Critic for Transportation, Infrastructure and Energy, advocated for the elimination of the residential second block. He explained that the declining block rate is out-of-date and encourages – rather than discourages – electricity consumption. The second block rate is also contrary to the preamble to the *Electric Power Act*, which states in part that "*public utilities should utilize energy efficiency and demand-side resource measures whenever it is cost-effective to do so*".

344. Mr. Howard expressed concern over the impact that the current rate structure, and particularly the residential second block, has on low-income Islanders. He explained that low-income Islanders spend a larger proportion of their income on energy costs, and have less ability to reduce their carbon footprint and energy use.

345. Mr. Howard also noted that while farm customers continue to benefit from the lower second block rate, the majority of Residential customers fall into the more expensive first block rate. Mr. Howard pointed to previous Commission Orders that state that the residential second block is neither fair, nor equitable.

346. In his submissions, Mr. Howard presented an alternate ascending block rate structure that would charge a higher rate for higher electricity consumption. The proposed rate structure would see the lowest consumers (those who consume less than 650 kWh per month in the summer, or 1,300 kWh per month in the winter) pay the lowest electricity rates. The rates would then increase with consumption, such that ratepayers who consume more than 3,000 kWh per month in the summer, or 5,000 kWh per month in the winter, would pay the highest rate. According to Mr. Howard, an ascending rate structure sends the appropriate price signal to customers while also encouraging energy efficiency.

347. The Commission also received written submissions from both the Prince Edward Island Federation of Agriculture and the Seafood Processors Association of Prince Edward Island.

348. As farms fall within the Residential rate class, the submissions from the PEI Federation of Agriculture focused on the proposed elimination of the residential second block. The Federation strongly opposes any plan that would see changes to the residential second block immediately or within the next year. From the Federation's perspective, "rushing" to change the residential second block does not make sense. Instead, the Federation advocates for additional time to gather more information and potentially mitigate the impact of eliminating the second block rate.

349. The Seafood Processors Association of PEI, on the other hand, focused on the Small Industrial rate class, as this is the rate applied to seafood plants. The Association explained that seafood processors require significant amounts of electricity on a monthly basis. As a result, even a 0.7 percent rate increase will result in added expense for seafood operators, albeit minor. The Association noted that seafood operators are not monopolies, like MECL. As a result, they are either required to absorb the additional expenses or pass them on to customers, making them less competitive in the marketplace. The Association emphasized the need for competitive and consistent electricity rates to ensure the future success of the Province, as well as the need for MECL to ensure its monopoly is operated in the most efficient manner possible.

350. It should be noted that the Small Industrial rate class, unlike farms, has a RTC ratio of 102 percent. This means that the Small Industrial customers, including seafood plants, are already paying slightly more than the cost to serve those customers.

12.4 Findings

351. In accordance with the *Electric Power Act*, rates for electric service should be reasonable, publicly justifiable and non-discriminatory.

352. Based on the results of the 2017 Cost Allocation Study, it is clear that farms within the Residential rate class have a RTC ratio of 82 percent. This means that farms are paying 18 percent less than the actual cost to serve them.

353. The 18 percent "discount" that farms have benefitted from is not simply written-off, nor is it borne by MECL. Instead, the difference is collected from other MECL customers. This includes Small Industrial customers, who have a RTC ratio of 102 percent and are therefore paying two percent more than the cost to serve them. It also includes General Service customers, who have a RTC ratio of 122 percent and are therefore paying 22 percent more than the cost to serve them.

354. This subsidization of large farming operations consuming significant amounts of electricity by other ratepayers is not reasonable, publicly justifiable or non-discriminatory.

355. This Commission has stated this exact finding a number of times, most recently as part of its decision in the 2016 General Rate Application (see **Order UE16-04R**). At that time, the Commission stated that the continued existence of the residential second block was contrary to the principles behind the *Electric Power Act*.

356. The Commission also explained that the elimination of the residential second block has historically been opposed by the farming community and the government of the day. The same is true in this Application.

357. The Commission recognizes that a change to simply eliminate the residential second block will have a significant impact on farms that are currently within the Residential rate class. However, the reality is that farms, as a class, have been paying significantly less than the cost to serve them for more than twenty years. And for more than twenty years, other ratepayers in this Province have been paying more than their fair share of electricity costs to make up the difference.

358. The subsidization of farms of all size by other ratepayers is not reasonable, publicly justifiable or non-discriminatory. A large industrial farming operation that consumes hundreds of thousands of kilowatt hours per month should not be classified as part of a Residential rate class with a significant declining second block rate. Further, the Commission finds that there is no compelling evidence that the continued subsidization of large farming operations is equitable to all ratepayers.

359. According to the PEI Energy Corporation and the PEI Federation of Agriculture, additional time is needed to mitigate the impact of eliminating the residential second block. These same arguments were made before this Commission in 2016. Farm operations and the Province have now had more than three years to mitigate the impact of eliminating the residential second block. The Commission considers this to be adequate, and does not accept the argument that additional time is now needed.

360. The residential second block is not, however, the only aspect of MECL's rate structure that is contrary to the principles behind the *Electric Power Act*. General Service customers are currently paying 22 percent more than the cost to serve them. This is not reasonable, publicly justifiable, or non-discriminatory. This is also not a new development, and is consistent with the results of the 2014 Cost Allocation Study.

361. Despite General Service customers already paying significantly more than their cost of service, MECL is proposing a rate increase for General Service customers as part of the present Application. At the hearing, MECL was asked to justify the proposed rate increase for the General Service rate class in light of the already high RTC ratio. MECL was unable to do so.

362. These same issues were identified by the Commission in the 2016 General Rate Application. As a result, MECL was ordered by this Commission to undertake a rate design study to consider changes to the residential second block and to MECL's other rate structures. MECL was ordered to file the rate design study and a proposed rate structure with the Commission on or before April 30, 2018, for consideration as part of the present Application.

363. In April 2018, MECL advised the Commission that it required more time to complete the rate design study, and requested an extension to October 31, 2018. This extension was granted by the Commission (see **Order UE18-02**).

364. MECL did not, however, file the rate design study and proposed rate structure by October 31, 2018. Although MECL now says that it requires further data, this anticipated delay was not disclosed to the Commission at the time that the request for an extension was made in April 2018. In fact, the Commission was not aware until this Application was filed on November 30, 2018, that MECL did not complete the rate design study and proposed rate structure as ordered.

365. A comprehensive rate design study and rate structure are critical elements necessary to address the inequities in MECL's existing rate structure. As such, MECL's failure to file the rate design study and proposed rate structure, as ordered, is unacceptable.

366. Despite MECL's failure to file the rate design study and proposed rate structure, this Commission is not prepared to allow the inequities to continue during the rate setting period.

367. Instead, the Commission orders MECL to file, on or before **June 30, 2020**, a comprehensive rate design study and proposed rate structure. The purpose of the rate design study and proposed rate structure is to address any and all inequities in MECL's existing rate structure, including (but not limited to) inequities relating to the Residential rate class, the residential declining second block rate, farms, and General Service customers.

368. The Commission encourages MECL to consider the viability of the alternate rate structures proposed by Mr. King and Mr. Howard, including (but not limited to), time-of-use rates, the use of demand charges, ascending block rate structures, and the classification of customers based on energy usage rather than application.

369. Any rate structure proposed by the Company shall ensure that all customer classes have a RTC ratio within a range of 90 percent to 110 percent. According to Multeese, this is an appropriate short to medium term goal. However, the Company shall be required to move RTC ratios within a range of 95 to 105 over the longer term. The Commission deems a RTC ratio of 95 to 105 to be the appropriate target range for all rate classes and must be used by MECL for all rate classes commencing March 1, 2022.

370. At this time, the Commission does not accept or approve the proposed change to the Residential monthly service charge for Rural Residential customers, nor does it approve the increase to the residential second block threshold. The Commission finds it would be imprudent to approve these changes pending completion of a comprehensive rate design study and proposed rate structure, as ordered.

371. The Commission approves the classification of costs recommended in the Point Lepreau Cost Allocation Classification Study as filed. The classification of costs shall be used by the Company in future cost allocation studies.

372. The Commission does not require the Company to change its cost allocation methodology from a historic year to future year basis at this time.

13 CONCLUSION

373. In this Application, MECL sought approval of its rates, tolls and charges for electric service for a three year period, as well as approval of a number of other matters that will directly impact electricity rates for its customers. It is the role of the Commission to consider the evidence before it, and to establish rates, tolls and charges for electric service that are reasonable, publicly justifiable, and non-discriminatory. In doing so, the Commission must consider both the interests of the Company and the interests of ratepayers.

374. For all of the foregoing reasons, and considering the whole of the approvals sought by MECL, the Commission is satisfied that this Order represents a fair and reasonable outcome for both the Company and its ratepayers.

Order

WHEREAS on or about November 30, 2018, Maritime Electric Company, Limited ("MECL" or the "Company") filed an application with the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") pursuant to section 20 of the *Electric Power Act*, R.S.P.E.I. 1988, Cap. E-4, seeking, among other things, approval of the rates, tolls and charges for electric service for the three year period from March 1, 2019 to February 28, 2022 (the "Application");

AND WHEREAS on or about February 4, 2019, the Commission issued **Order UE19-01**, which Order consolidated the following dockets with the Application, and directed that they be heard together with the Application in Commission Docket UE20944:

- Point Lepreau Cost Allocation Classification Study in Commission Docket UE22502;
- Charlottetown Thermal Generating Station Decommissioning Study in Commission Docket UE23001;
- 2017 Depreciation Study in Commission Docket UE21604; and
- 2017 Cost Allocation Study in Commission Docket UE21222.

AND WHEREAS interrogatories were asked by Commission Staff and by expert witnesses retained on behalf of Commission Staff;

AND WHEREAS MECL filed responses to all interrogatories;

AND WHEREAS the interrogatory process was completed on or about May 24, 2019;

AND WHEREAS on or about June 27, 2019, the Prince Edward Island Energy Corporation applied for Friend of the Commission Intervener status to address matters of rate design and, in particular, the residential second block;

AND WHEREAS the PEI Energy Corporation was granted Friend of the Commission Intervener status pursuant to Commission **Order UE19-05**, dated July 4, 2019;

AND WHEREAS on or about August 1, 2019, Mr. Stephen Howard, MLA and Opposition Shadow Critic for Transportation, Infrastructure and Energy, applied for Friend of the Commission Intervener status specifically to address matters of rate design;

AND WHEREAS Mr. Howard was granted Friend of the Commission Intervener status pursuant to Commission **Order UE19-06**, dated August 2, 2019;

AND WHEREAS Mr. Roger King, an interested member of the public, did not apply for intervener status but was permitted to ask questions of witnesses and make an oral submission to the Commission as part of the hearing;

AND WHEREAS the public hearing of the Application was scheduled to commence on August 6, 2019;

AND WHEREAS on or about July 31, 2019, MECL filed revised schedules with the Commission and sought approval of revised rates which differed from those proposed in its Application;

AND WHEREAS the hearing commenced as scheduled on August 6, 2019, and concluded on August 9, 2019;

AND WHEREAS a Notice of Hearing was published on the Commission website, in local newspapers, and circulated via social media;

AND WHEREAS interested members of the public were invited to submit written comments to the Commission, and to participate in an evening session of the hearing held on August 8, 2019;

AND WHEREAS the Commission received approximately thirty-five written submissions or comments from members of the public, and heard oral submissions from two individuals as part of the evening session on August 8, 2019;

AND WHEREAS the Commission has considered all of the written and oral submissions made on behalf of the parties, Commission Staff, and members of the public;

NOW THEREFORE, pursuant to the *Electric Power Act*, the Commission orders as follows:

IT IS ORDERED THAT:

Rates

1. The rates, tolls and charges for electric service currently in effect for the period from March 1, 2018 to February 28, 2019, shall remain in effect until February 28, 2020, or until otherwise varied by the Commission.
2. The rates, tolls and charges for electric service effective March 1, 2020 and March 1, 2021 shall be determined upon the Company filing updated financial information as at December 31, 2019. The updated financial information shall be filed with the Commission on or before January 31, 2020. The form and content of the financial information shall be determined by the Commission.

General Rules & Regulations

3. The Company's General Rules and Regulations shall be amended to:
   a) incorporate the amendments to the Large Industrial Rate Schedule Guidelines as proposed in the Application; and
   b) incorporate the terms of this Order.
4. The amended General Rules and Regulations shall be filed with the Commission on or before October 31, 2019.

Rate of Return

5. MECL shall be entitled to earn a maximum return on average common equity of 9.35 percent based on 40 percent average common equity in each of 2019, 2020 and 2021, or until otherwise varied by the Commission.

6. The Commission does not approve the earnings sharing mechanism as proposed by MECL.

Energy Cost Adjustment Mechanism

7. The Commission does not approve the recovery of Provincial Costs Recoverable through the Energy Cost Adjustment Mechanism ("ECAM"), and does not approve the corresponding re-basing of the ECAM base rate to include the Provincial Costs Recoverable.

8. The Provincial Costs Recoverable shall continue to be collected through a rate rider in basic rates.

9. MECL shall undertake a thorough review of the ECAM as it currently exists, including the expenses and accounts that are currently collected through the ECAM, and the practice of deferring a portion of the energy supply costs for collection from future ratepayers. MECL shall file its review, together with any resulting recommendations, with the Commission on or before April 1, 2020.

Rate of Return Adjustment

10. MECL shall refund the balance of the post-2015 Rate of Return Adjustment ("RORA") account, together with interest, to ratepayers commencing March 1, 2020.

11. The RORA balance shall be used to minimize the proposed rate increase for the period from March 1, 2020 to February 28, 2021.

12. In the event the balance of the post-2015 RORA account is sufficient to ensure that there is no rate increase effective March 1, 2020, yet there is still a balance remaining in the post-2015 RORA account, the remaining balance shall be refunded to ratepayers during the period from March 1, 2021 to February 28, 2022.

13. The RORA refund rates shall be such that the post-2015 RORA account shall be fully refunded to ratepayers, and shall therefore have a zero balance, on or before February 28, 2022.

14. The RORA account shall not be used as a deferral account to collect over-earnings during the current rate setting period. Instead, any over-earnings earned in 2019, 2020 and/or 2021 shall be determined by the Company as at December 31 of each year, and refunded to ratepayers on a per kWh basis within 60 days of the calendar year-end.

15. The Company shall file with the Commission, on or before January 31 in each of 2020, 2021 and 2022, the balance of the RORA account as at December 31 in the preceding year, together with the proposed per kWh refund (if any).

16. The Company shall continue to file the balance of the RORA account with the Commission on a monthly and annual basis.

Weather Normalization Mechanism

17. The Weather Normalization Mechanism and Reserve account are approved on an interim basis only until February 28, 2022.

18. MECL shall continue to file the monthly balance of the Weather Normalization Reserve with the Commission as part of its monthly reporting requirements.
19. The Company shall also file, on or before January 31 in each of 2020, 2021 and 2022, the year-end balance of the Weather Normalization Reserve account.

CTGS Decommissioning

20. The Commission does not approve the proposed demolition of the existing Steam Plant Building at the Charlottetown Thermal Generating Station ("CTGS") site, and does not approve the proposed construction of a new balance of plant.
21. The Commission approves all other aspects of the decommissioning plan as proposed by GHD.
22. MECL shall complete all necessary environmental testing and other necessary follow-up on risk items before commencing the decommissioning. If necessary, MECL shall modify its budgeting and workplan based on the results of the testing and shall file a copy of the revised budget and workplan with the Commission prior to commencing the decommissioning.
23. MECL shall file written reports with the Commission every six months from the date of commencement of the decommissioning. The reports shall provide updates on costs, project timelines, and any variations from the approved budget.
24. In the event the cost of the decommissioning varies by plus or minus $500,000.00, MECL shall be required to apply to the Commission for approval of the variance.
25. The Company shall file with the Commission, on or before September 30, 2020, a long-term plan for energy system utilization at the CTGS site. In the interim, the entire CTGS site shall be deemed used and useful. The Commission shall determine whether all or part of the CTGS site shall continue to be classified as used and useful upon receipt and review of the long-term plan.
26. MECL shall undertake the following investigations and file the results, together with any recommendations, with the Commission on or before September 30, 2020:
    a) A detailed study of the Island transmission system to determine its capabilities under high import situations;
    b) The use of transmission, generation and peak load management techniques in order to accommodate the growing peak load and potential high imports; and
    c) Whether additional on-Island generation is the optimal solution.

Amortization Rates

27. MECL shall adopt all of the recommendations made by Gannett Fleming in the 2017 Depreciation Study. This includes, without limitation, the adoption of the proposed depreciation rates and the amortization of the accumulated reserve variance for all assets.
28. The depreciation rates and amortization of the accumulated reserve variance shall be adopted as of January 1, 2020, and shall be included in the Company's revenue requirement for rates effective March 1, 2020 and March 1, 2021.

29. MECL shall undertake a new depreciation study based on financial results up to December 31, 2020. The depreciation study shall be filed with the Commission no later than June 30, 2021.

Cost Allocation & Rate Design

30. The Commission does not approve the proposed change to the Residential monthly service charge for Rural Residential customers, and does not approve the proposed increase to the residential second block threshold at this time.
31. MECL shall file, on or before June 30, 2020, a comprehensive rate design study and proposed rate structure, as set out in this Order.
32. The rate structure proposed by the Company shall ensure that all rate classes have a revenue-to-cost ("RTC") ratio within a range of 90 percent to 110 percent.
33. The Commission deems a RTC ratio of 95 percent to 105 percent to be the appropriate target range for each of the Company's rate classes and must be used by MECL for all rate classes commencing March 1, 2022. However, a RTC range of 90 percent to 110 percent is an appropriate short to medium term goal for the Company.
34. The classification of costs set forth in the Point Lepreau Cost Allocation Classification Study are approved as filed. The classification of costs shall be used by the Company in future cost allocation studies.

DATED at Charlottetown, Prince Edward Island, on Friday, September 27, 2019

BY THE COMMISSION:

(sgd) J. Scott MacKenzie

J. Scott MacKenzie, Q.C., Chair

(sgd) M. Douglas Clow

M. Douglas Clow, Vice-Chair

(sgd) John Broderick

John Broderick, Commissioner

NOTICE

Section 12 of the ***Island Regulatory and Appeals Commission Act*** reads as follows:

> *12. The Commission may, in its absolute discretion, review, rescind or vary any order or decision made by it, or rehear any application before deciding it.*

Parties to this proceeding seeking a review of the Commission's decision or order in this matter may do so by filing with the Commission, at the earliest date, a written Request for Review, which clearly states the reasons for the review and the nature of the relief sought.

Sections 13(1) and 13(2) of the ***Act*** provide as follows:

> *13(1) An appeal lies from a decision or order of the Commission to the Court of Appeal upon a question of law or jurisdiction.*
>
> *(2) The appeal shall be made by filing a notice of appeal in the Court of Appeal within twenty days after the decision or order appealed from and the rules of court respecting appeals apply with the necessary changes.*

NOTE: In accordance with IRAC's *Records Retention and Disposition Schedule*, the material contained in the official file regarding this matter will be retained by the Commission for a period of 2 years.