AUC
Alberta Utilities Commission

2011 Generic Cost of Capital

December 8, 2011

The Alberta Utilities Commission
Decision 2011-474: 2011 Generic Cost of Capital
Application No. 1606549
Proceeding ID No. 833

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1 Introduction

1. This decision sets out the approved generic return on equity (ROE) for all affected utilities for 2011. It also sets out the Commission's findings with respect to the proposal to re-introduce a formula by which the ROE would be adjusted on an annual basis beyond 2011. The ROE is referred to as "generic" because the approved ROE applies uniformly to all affected utilities. The affected utilities (the Utilities) are:

AltaGas Utilities Inc. (Gas Distribution)
AltaLink L.P. (Electricity Transmission)
ATCO Electric Ltd. (Electricity Distribution and Transmission)
ATCO Gas (Gas Distribution)
ATCO Pipelines (Gas Transmission)
ENMAX Power Corporation (Electricity Distribution and Transmission)
EPCOR Distribution & Transmission Inc. (Electricity Distribution and Transmission)
FortisAlberta Inc. (Electricity Distribution)

2. This decision also sets out individual deemed common equity ratios for each affected utility. Given that the generic ROE is uniformly applied to all of the Utilities, the Commission has accounted for differences in the risk of each utility by adjusting the utility-specific equity ratios.

3. In addition to the above-listed Utilities, all of which participated in this proceeding, there are additional utilities under the Commission's jurisdiction that could be affected by this decision, which were also made aware of, and invited to participate in, this proceeding. As indicated in the notice of this proceeding, the additional utilities include, but are not limited to:

Various investor-owned water utilities regulated by the Commission
EPCOR Energy Alberta Inc. (Regulated Retail Electricity Operations)
ENMAX Energy Corporation (Regulated Retail Electricity Operations)
Direct Energy Regulated Services (Regulated Retail Electricity and Gas Operations)
City of Lethbridge (Electricity Distribution and Transmission)
City of Red Deer (Electricity Distribution and Transmission)
TransAlta Corporation (certain transmission assets)

4. None of these utilities participated in the proceeding. The ROE and debt to equity ratios in this decision do not automatically apply to EPCOR Energy Alberta Inc., ENMAX Energy Corporation and Direct Energy Regulated Services because they are regulated pursuant to the *Regulated Rate Option Regulation* and the *Default Gas Supply Regulation*. The ROE established in this decision will apply to City of Lethbridge Transmission, City of Red Deer Transmission

and TransAlta Corporation's transmission assets. In addition, the Commission has established the equity ratios for each of these utilities. Specific ROEs and capital structures for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding, because the Commission considers these utilities only in response to a complaint. However, the determinations made in this proceeding may be considered in any cost of capital determinations for these utilities under the Commission's jurisdiction, should issues respecting these matters arise.

5. This decision also sets out the Commission's findings with respect to the proposal for a management fee to compensate the utilities for the management of contributed assets. Specifically, the decision considers whether the Commission has jurisdiction to approve a management fee, and whether a management fee is warranted and in the public interest.

6. Finally, this decision addresses the AESO's proposed "Rider I" by which certain customers would be permitted to pay construction contributions in excess of the maximum investment levels approved by the Commission, in equal monthly amounts, over a period of up to 20 years.

2 Procedural summary highlights

7. On September 17, 2010, the Commission initiated this 2011 Generic Cost of Capital (GCOC) Proceeding as ID No. 833 and sought preliminary comments on the scope and schedule for this proceeding.

8. On December 16, 2010, the Commission issued a formal notice of this proceeding and issued a letter detailing the scope of the proceeding. The scope included a full review of the generic ROE and capital structure for each affected utility for 2011, consideration of an annual ROE adjustment formula, or other approach, to be applicable after 2011, and consideration of a management fee on customer contributed assets. Subsequently, Decision 2010-606[1] indicated that consideration of Rider I would be included in the scope of the Generic Cost of Capital Proceeding and this was confirmed in this proceeding in a Commission letter dated January 17, 2011.

9. The division of the Commission assigned to this application is comprised of Commission Member Bill Lyttle; Commission Member Mark Kolesar and Commission Member Moin A. Yahya, who chaired the panel.

10. Notice of this proceeding was published on December 16, 2010, in the four largest newspapers in the province: The Edmonton Journal, the Calgary Herald, the Edmonton Sun, and the Calgary Sun. In addition, the notice was circulated by email to the parties registered for the 2009 GCOC proceeding and to the Commission's general email lists for gas and electric proceedings.

11. The Utilities, after registering individually, worked together and filed a joint submission. The interveners that were active in the proceeding were the Industrial Power Consumers Association of Alberta (IPCAA), the Alberta Electric System Operator (AESO – which

[1] Decision 2010-606: Alberta Electric System Operator, 2010 ISO Tariff, Application No. 1605961, Proceeding ID. 530, December 22, 2010.

registered as the Independent System Operator), the Consumers' Coalition of Alberta (CCA), the Office of The Utilities Consumer Advocate (UCA), and the Canadian Association of Petroleum Producers (CAPP).

12. Expert evidence was sponsored by several parties. The Utilities sponsored:

Ms. Kathleen McShane , B.A., M.A, MBA, CFA, President and senior consultant with Foster Associates Inc. of Bethesda, Maryland

Aaron M. Engen, B.A., LLB, MBA, Managing Director, Investment and Corporate Banking, Power & Utilities Group at BMO Capital Markets

CAPP sponsored:

Dr. Laurence Booth, B.Sc., M.A., M.B.A., D.B.A. of the University of Toronto.

The UCA sponsored, as a team:

Dr. Lawrence Kryzanowski, B.A., Ph.D., of Concordia University

Dr. Gordon S. Roberts, B.A., Ph.D., of York University

13. As indicated in the Commission's scope letter of December 16, 2010,[2] for expediency and in order to minimize costs, the complete record of the 2009 GCOC proceeding was incorporated into this proceeding. The complete evidentiary record of this proceeding is filed in the Commission's electronic system under Proceeding ID No. 833. The Commission considers that the close of record for this proceeding was September 9, 2011, which is the date on which reply argument was filed.

14. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. 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 2011 return on equity

3.1 Introduction

15. The Commission has set out its findings in this section of the decision generally following the same structure as the return on equity section of Decision 2009-216.[3]

16. Parties to the proceeding were asked to address the ROE for 2011 because it had been anticipated that the ROE for 2012 was to be dealt with by way of a formula, or by some other

[2] Exhibit 11.

[3] Decision 2009-216: 2009 Generic Cost of Capital, Application No. 1578571, Proceeding ID. 85, November 12, 2009.

method, in the absence of a formula. However, some of the experts also addressed 2012 directly in their ROE evidence.

17. To satisfy the fair return standard, the Commission is required to determine a fair return on equity for the utilities. The Commission was again presented with a significant body of evidence on the tests to be considered when determining the fair ROE, a number of opinions on the proper methodology to be employed for many of the tests and, as a result, a wide range of proposed ROEs. Briefly, the record of the proceeding included evidence to support ROE estimates based on:

- changes in the financial environment since the 2009 proceeding
- the capital asset pricing model (CAPM)
- the discounted cash flow model (DCF) which was applied to proxy utilities as well as to the equity market overall
- other evidence on comparable investments
- ROE awards by other Canadian regulators
- market price-to-book values
- returns on high grade bonds
- the return expectations from pension and investment managers
- the impact of growth on the required ROE

18. On the basis of this evidence, the Commission was presented with the following recommended ROEs for 2011 and 2012.

Table 1. Summary of ROE recommendations

	Recommended By the Utilities[4] (%)	Recommended by UCA[5] (%)	Recommended by CAPP (%)[6]
2011	10.375	8.3	7.75
2012	10.375	8.4	8.15

19. In this decision, the Commission has established a generic ROE for 2011. In Section 4 dealing with the adoption of a formula for adjusting the ROE beyond 2011, the Commission has determined that it will not adopt a formula at this time and that the ROE for 2012 will be the same as the ROE for 2011.

3.2 Changes in the financial environment since Decision 2009-216

20. Dr. Booth submitted that the Canadian economy was recovering from the financial crisis while the U.S. economy was still weak.[7] He submitted that Canada was two years out of

4 Exhibit 209, Utilities argument, paragraph 122.
5 Exhibit 210, UCA argument, paragraphs 149 and 150.
6 Exhibit 207, CAPP argument, paragraph 114.
7 Exhibit 207, CAPP argument, page 4.

recession but still had a long way to go.[8] He indicated that the situation in the United States during the financial crisis was "horrendous" but that "now it's less stressful" and that the major impact of the financial crisis has passed. Dr. Booth stated that spreads are still higher in Canada than they were but there is no stress in the financial system in Canada and corporate bond yields have come down.[9] Dr. Booth noted the (then existing) risk that the United States would not increase its debt ceiling.[10]

21. The UCA submitted that there is no dispute that economic conditions have improved since the conclusion of the 2009 GCOC hearing in June 2009. It submitted that 30-year utility bond spreads have declined by 50 basis points since then, that the 2008-2009 crisis is over and has been over for two years, and that we are now in a more typical post-recessionary recovery that is distinguishable from the extraordinary crisis mere months before the 2009 hearing. The UCA also stated that economic parameters have improved significantly and for all practical purposes have "normalized."[11]

22. The UCA proposed that, because there is agreement that conditions have improved directionally since the end of the 2009 proceeding, financial conditions are not a justification for increasing the allowed ROE, as the Utilities would urge.[12]

23. The CCA noted that the intervener and utility experts agreed that capital markets have improved since 2009.[13]

24. The Utilities argued that, although financial markets have stabilized to some degree relative to 2009, risk remains elevated and risk has been re-priced as evidenced by credit spreads.[14] They cited a World Economic Forum publication of January 2011 which had indicated there were ever-greater concerns regarding global risks and "the prospect of rapid contagion through increasingly connected systems and the threat of disastrous impacts."[15]

25. The Utilities noted that Dr. Booth had volunteered that there were significant risks remaining in the global financial system and that his 8.15 per cent recommendation for 2012 was 90 basis points higher than he had recommended in 2009 at the same 4.5 per cent long-term Canada bond yield forecast, in part due to continuing uncertainties.[16]

26. The following chart from Exhibit 172 illustrates how the 30-year bond spread for Canadian relatively pure-play regulated utilities had been relatively stable since 2001 but increased sharply (to unprecedented levels) during the financial crisis, and then largely (but not

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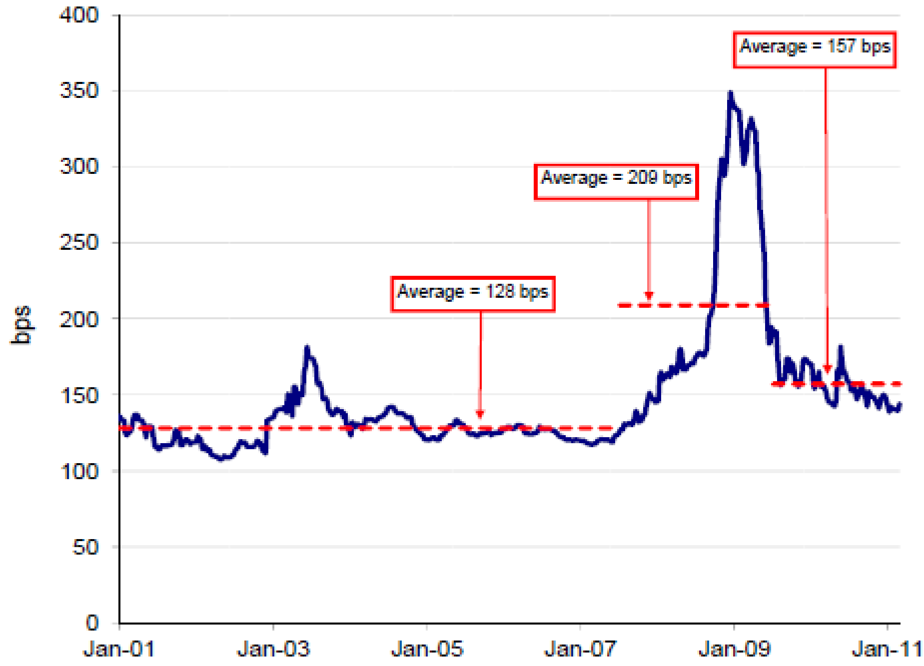
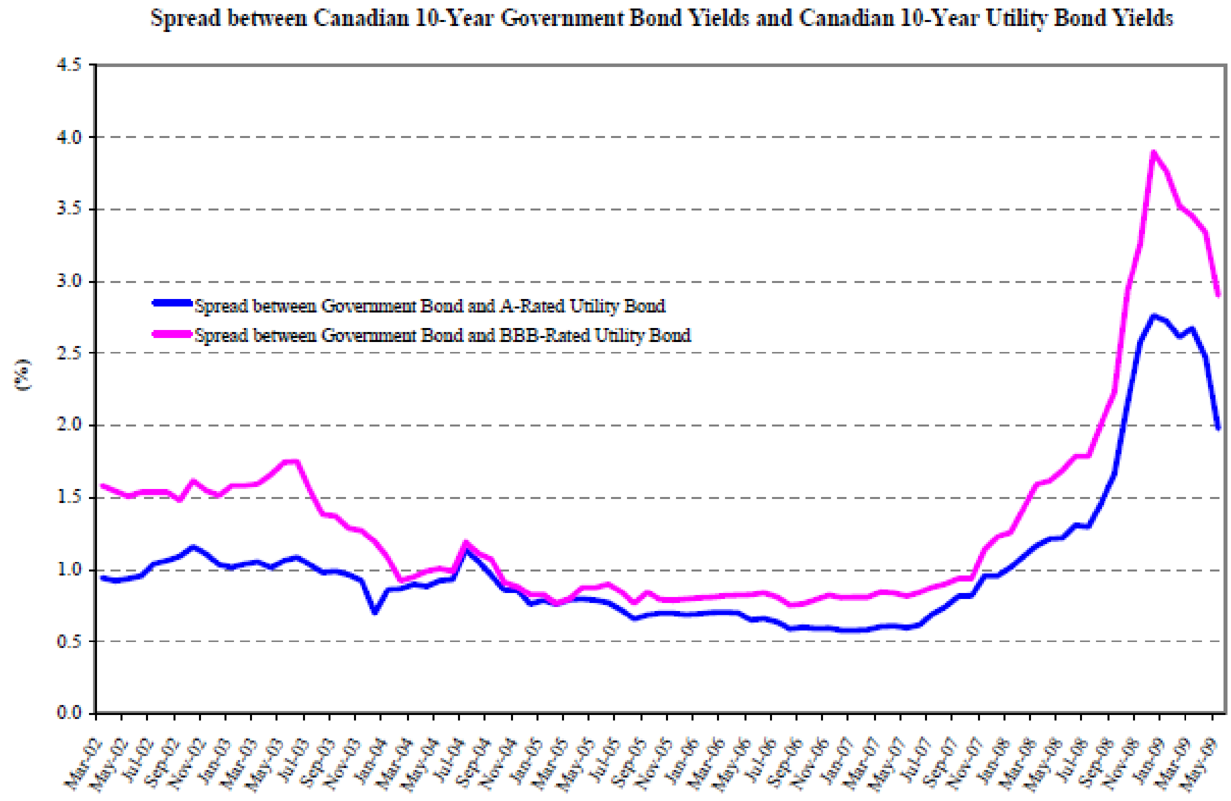
8 Exhibit 207, CAPP argument, page 6.
9 Exhibit 207, CAPP argument, page 11 and 12.
10 Exhibit 207, CAPP argument, page 13.
11 Exhibit 210, UCA argument, paragraphs 8, 10 and 11.
12 Exhibit 221, UCA reply argument, paragraph 5.
13 Exhibit 211, CCA argument, paragraph 15.
14 Exhibit 208, Utilities argument, paragraph 11.
15 Exhibit 208, Utilities argument, paragraph 25.
16 Exhibit 220, Utilities reply argument, paragraphs 19, 21 and 22.

completely) recovered.



27. For comparison, the Commission notes the following chart from paragraph 301 of Decision 2009-216, which illustrates utility corporate bond spreads prior to the credit crisis and during the credit crisis, up to the time of the 2009 hearing. It indicates that the recovery had begun by the end of the 2009 hearing.



28. From the charts above, the Commission finds that corporate bond spreads had begun to recover at the time of the 2009 hearing but had far from fully recovered. The Commission also finds that, in contrast, by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels.

3.3 Capital asset pricing model

29. CAPM is a well-accepted and theoretically-grounded economic model for valuing securities based on the relationship between non-diversifiable risk and expected return. CAPM is based on the principle that investors need to be compensated in two ways: for the time value of money and for risk. In the model, the time value of money is represented by the rate that compensates the investor for placing money in a risk-free investment over a period of time (the risk-free rate). The second part of the model considers risk and estimates the compensation that the investor needs for taking on the risk that the expected return will not be realized. This element of risk is calculated by taking a risk measure (beta) based on the statistical relationship between the historical returns for the investment security relative to the historical returns for the market as a whole, over time. Beta is a risk measure that describes how sensitive the expected return of a security is to the market. Hence, CAPM calculates the expected return for a security as the rate of return on a risk free security plus a risk premium.

30. Evidence to support proposed ROEs based on an application of CAPM was provided by Ms. McShane, Dr. Booth, and Drs. Kryzanowski and Roberts.

31. The following table sets out the recommended individual CAPM components and resulting ROE levels for each of the experts that presented evidence on CAPM.

Table 2. CAPM recommendations

Expert Witness	Risk-free Rate (%)	MERP (%)	Market Return (%)	Beta	Adder	Flotation Allowance (%)	ROE (%)
Dr. Booth 2011	4.10	5.0 to 6.0	9.1 -10.1	0.45 -0.55	0.25 - 0.50	0.50	8.15 (7.5 - 8.8)
Dr. Booth 2012	4.50	5.0 to 6.0	9.5 -10.5	0.45 -0.55	0.25 - 0.50	0.50	7.75 (7.10 - 8.4)
Drs. Kryzanowski & Roberts[17] (At their equity ratio recommendation)	4.20	5.2	9.4	0.52	0.90[18]	0.50	8.3.
Drs. Kryzanowski & Roberts (At higher equity ratios)	4.20	5.2	9.4	0.52		0.50	7.4
Ms. McShane	4.25[19]	7.25[20]	11.5[21]	0.65 – 0.70[22]		1.0[23]	10.0 -10.3[24]

32. Ms. McShane also provided two additional estimates of the equity risk premium. These were developed on a DCF-based method and on historically achieved utility equity risk premiums. The Commission has considered Ms. McShane's DCF results in the DCF section below, rather than considering them in this CAPM section. Similarly, the Commission has considered Ms. McShane's historic utility return data in the comparable investments section below and not in this CAPM section.

33. Dr. Booth confirmed that his explanation of the CAPM provided in the 2009 proceeding remains his view:

> Why the CAPM is so widely used is because it is intuitively correct. It captures two of the major "laws' of finance: the time value of money and the risk value of money…the time value of money is captured in the long Canada bond yield as the risk free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm's risk. As long as the market risk premium is approximately correct the estimate will be in the right "ball-park." Where the CAPM gets controversial is in the beta coefficient; since risk is constantly changing so too are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further it also makes testing the model incredibly difficult. However, the CAPM measures the right thing: which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory.[25]

34. Drs. Kryzanowski and Roberts indicated that they had added 90 basis points to their CAPM estimate to be consistent with an A credit rating and a 1.2 price-to-book value ratio, but that the adjustment would not be needed if the Commission adopts higher equity ratios than they

17 Exhibit 210, UCA argument, paragraphs 72-75.
18 Exhibit 210, UCA argument, paragraphs 75 and 78.
19 Exhibit 208, Utilities argument, paragraph 55.
20 Exhibit 86.01, Kathleen McShane opinion, page 55 line 1343.
21 Exhibit 86.01, Kathleen McShane opinion, page 55 line 1344.
22 Exhibit 86.01, Kathleen McShane opinion, page 63, line 1518.
23 Exhibit 86.01, Kathleen McShane opinion, page 79, lines 1934-1938.
24 Exhibit 86.01, Kathleen McShane opinion, page 63, line 1527 and page 79, lines 1934-1938.
25 Exhibit 207, CAPP argument pages 14 and 15 and paragraph 224 of Decision 2009-216.

recommended.[26] For this reason, the Commission included two CAPM ROE recommendations for Drs. Kryzanowski and Roberts in the table above. The Utilities submitted that Drs. Kryzanowski and Roberts' CAPM estimate was, by their own admission, insufficient for an A credit rating until they had made a credit metric adjustment.[27]

35. In considering the evidence on CAPM, the Commission reviewed the proposals on the individual components of CAPM, as well as each party's overall ROE estimate based on the CAPM approach. Each CAPM component, and the overall resulting CAPM estimates of ROE, are addressed below.

3.3.1 Risk-free rate

36. The CAPM analysis starts from a forecast of the risk-free rate.

37. Ms. McShane, on behalf of the Utilities, estimated the 2011-2012 average long-term Canada bond yield at 4.25 per cent.[28] This was an average of her 4.0 per cent forecast for 2011, based on the January 2011 Consensus Economics forecast and the December 2010 spread between the 30-year and 10-year Canada bonds, and her 4.5 per cent estimate for 2012 based on the most recent forecasts from major Canadian banks.[29]

38. Dr. Booth forecast a risk-free rate of 4.50 per cent for 2012, indicating that this was somewhat higher than his 2009 forecast, given that Canada is further along in its recovery. Dr. Booth had considered the Consensus Economics forecast, as well as that of the Royal Bank of Canada, and he discussed the views of the Bank of Canada. He forecast a rate of 4.10 per cent for 2011 but supported the use of 4.50 per cent for both 2011 and 2012.[30]

39. Drs. Kryzanowski and Roberts forecast the 30-year bond yield at 4.20 per cent for 2011 based on the Consensus Economics forecast and recently observed spreads between the 30-year and 10-year Canada bonds; adding 15 basis points for more recent movements in the 10-year yield.[31]

40. The UCA noted that all of the experts had applied judgment to arrive at a risk free rate similar to 2009, even though actual long-term Canada bond rates and the Consensus Economics forecast used in the National Energy Board's formula indicated a reduction of 60 basis points since 2009.[32]

41. The Commission notes that the latest available Consensus Economics forecast on the record, from July 2011, forecast a 10-year Government of Canada bond rate for October 2011 of 3.3 per cent and for July 2012 of 3.8 per cent.[33] Adding 50 basis points for the spread between the 10-year and the 30-year bond forecasts results in a 30-year forecast of 3.8 per cent for October 2011 and 4.3 per cent for July 2012.

[26] Exhibit 210, UCA argument, paragraphs 75 and 78.
[27] Exhibit 208, Utilities argument, paragraphs 48 -51.
[28] Exhibit 208, Utilities argument, paragraph 55.
[29] Exhibit 86.01, Kathleen McShane opinion, page 52, lines 1094 to 1104.
[30] Exhibit 207, CAPP argument, page 16.
[31] Exhibit 210, UCA argument, paragraph 25.
[32] Exhibit 221, UCA reply argument, paragraph 34.
[33] Exhibit 204.01.

42. The July 2011 Consensus Economics forecast, referenced above, also indicated that the actual 10-year Government of Canada bond yield in July 2011 was 2.9 per cent. At the time of the 2009 hearing, the actual 10-year Canada bond interest yield was 3.5 per cent.[34] Therefore, the Commission notes that the 10-year Canada bond yield declined 60 basis points from the 2009 hearing to the 2011 hearing.

43. The Consensus Economics forecast has traditionally been used by the Commission and its predecessor to estimate the risk free rate. In 2009, the Commission found that a risk free rate in the range of 4.13 per cent to 4.50 per cent was reasonable, based on the Consensus Economics forecast at that time. Based on the Consensus Economics forecasts and the July 2011 actual 10-year interest rate of 2.9 per cent, on the record of this proceeding, the Commission considers that a long-term bond yield forecast of 3.4 per cent to 3.8 per cent for 2011 is reasonable, considering the current volatility in rates and the 60 basis point decline since 2009.

3.3.2 Market equity risk premium

44. The next element of the CAPM analysis is the market equity risk premium (MERP). Parties recommended a number of market equity risk premiums.

45. The Utilities argued that an arithmetic average market equity risk premium should continue to be used, rather than the lower geometric average.[35] Ms. McShane submitted that arithmetic average returns have been 1.7 per cent higher than the geometric average in Canada since 1924 and 2.0 per cent higher in the U.S. since 1926. She submitted that the arithmetic average was 1.3 per cent and 1.5 per cent higher than the geometric average for Canada and the U.S., respectively, in the post war period.[36]

46. Ms. McShane submitted that historic risk premium data should not be used without considering that today's environment may be different.[37] In support of this, she relied on her analysis which, she submitted, demonstrated that equity returns and risk premiums have tended to be higher when (as now) bond interest rates are low.[38] She also submitted that her analysis demonstrated that equity returns have been higher when (as now) inflation is low.[39] The Utilities argued that Drs. Kryzanowski and Roberts' proposed adjustment formula implicitly suggests that the equity market return does not decline with lower interest rates, which supports the Utilities' position.[40]

47. Dr. Booth estimated that the market equity risk premium is five per cent and indicated that a range of 5.0 to 6.0 per cent was reasonable.[41]

48. The UCA submitted that the use of a longer historical period can improve the accuracy of the market equity risk premium estimate in a statistical sense but may introduce errors because historical conditions may differ from today. In particular, the UCA submitted that trading costs and impediments to foreign diversification may explain higher historical risk premiums.

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34 Exhibit 367.02 of Proceeding 85, 2009 Generic Cost of Capital.
35 Exhibit 208, Utilities argument, paragraphs 57 and 58.
36 Exhibit 86.01, Kathleen McShane opinion, page 52 lines 1269-1271.
37 Exhibit 86.01, Kathleen McShane opinion , lines 1083-1085.
38 Exhibit 86.01, Kathleen McShane opinion, page 49, Table 9.
39 Exhibit 86.01, Kathleen McShane opinion, page 54, Table 12.
40 Exhibit 219, Utilities reply argument, paragraph 38.
41 Exhibit 207, CAPP argument, page 17.

Drs. Kryzanowski and Roberts estimated the market equity risk premium at 5.2 per cent using a weighting of 75 per cent geometric average and 25 per cent arithmetic average and considering various historical periods in both Canada and the U.S.[42]

49. Drs. Kryzanowski and Roberts submitted that Ms. McShane's evidence failed to test whether this inverse relationship had been expected by investors, that she had not provided tests of significance and that she failed to adjust for unique past events including wage and price controls.[43] Drs. Kryzanowski and Roberts submitted that the most damaging argument against Ms. McShane's results were that they were inconsistent with the return expectations of investment professionals.[44] However, the Commission notes that the "different results" that Drs. Kryzanowski and Roberts noted, based on geometric returns, still indicated equity returns that were inversely correlated to inflation.[45]

50. Ms. McShane estimated that the market risk premium, at her forecast 4.25 per cent long-term Canada bond yield, was 6.5 per cent to 8.0 per cent or, using the mid-point, approximately 7.25 per cent.[46]

51. The Utilities submitted that equity market returns have not declined, but that achieved bond returns have increased as interest rates declined. They submitted that market risk premiums have not declined when measured against the bond income returns which, they argued, is the risk-free rate which should be used in the CAPM since it is the risk free portion of bond returns.[47] The Commission notes that Ms. McShane's equity market risk premium was based on the premium over bond yields, rather than over bond total returns. The Commission also notes that, if the market equity risk premium is constant, then equity returns would also have been impacted by lower interest rates. For this reason, Ms. McShane's proposal appears to compare a return on bonds which excludes capital gains caused by lower interest rates, to a return on equities that may include capital gains directly caused by lower interest rates. This does not appear to be consistent. The Commission is not convinced that it should base the market equity risk premium on bond income-only returns, rather than bond total returns, which is the traditional approach.

52. The Commission notes that long-term average data on achieved historical market risk premiums are usually used to estimate the required market equity risk premium going forward. However, in this proceeding, Ms. McShane has provided evidence that the market equity risk premium varies inversely with interest rates and inflation, and the UCA noted that using data from longer periods of time could introduce errors if historical conditions differ from those of today. For these reasons, the Commission is not prepared to use the long-term historical market risk premium as the applicable market equity risk premium for 2011, given that the risk free rate is far below its long-term historical average. The Commission also considered ongoing arguments about whether the geometric or the arithmetic average risk premium should be used, the observation that realized equity risk premiums were not necessarily the risk premiums that investors had expected, and the possibility that historic realized premiums are not necessarily reflective of future expectations.

42 Exhibit 210, UCA argument, paragraphs 27 and 30.
43 Exhibit, 142.02, rebuttal evidence of UCA, paragraphs 27 to 37.
44 Exhibit, 142.02, rebuttal evidence of UCA, paragraph 38.
45 Exhibit, 142.02, rebuttal evidence of UCA, paragraph 34.
46 Exhibit 86.01, Kathleen McShane opinion, page 55, lines 1341-1342.
47 Exhibit 220, Utilities reply argument, paragraphs 34 and 35.

53. The Commission has explored the relationship, discussed by Dr. Booth, of the market return, the utility return and the market equity risk premium implied by ROE formulas that allow the utility ROE to change with interest rates, as set out in tables 3 and 4 below.

Table 3. Formula results when utility ROE changes at 75 per cent of change in risk free rate and beta is 0.55

Risk free rate	Beta	Implied market risk premium	Implied market return	Formula utility return	Note
5.0%	**0.55**	**5.00%**	**10.00%**	**7.75%**	**Initial ROE**
6.0%	0.55	4.55%	10.55%	8.50%	Formula Result
7.0%	0.55	4.09%	11.09%	9.25%	Formula Result
4.0%	0.55	5.45%	9.45%	7.00%	Formula Result
3.0%	0.55	5.91%	8.91%	6.25%	Formula Result

Source: Commission staff calculations based on Dr. Booth's evidence. (Exhibit 78.02, pages 72-73).

Table 4. Formula results when utility ROE changes at 50 per cent of change in risk free rate and beta is 0.50

Risk free rate	Beta	Implied market risk premium	Implied market return	Formula utility return	Note
5.0%	**0.50**	**6.00%**	**11.00%**	**8.00%**	**Initial ROE**
6.0%	0.50	5.00%	11.00%	8.50%	Formula Result
7.0%	0.50	4.00%	11.00%	9.00%	Formula Result
4.0%	0.50	7.00%	11.00%	7.50%	Formula Result
3.0%	0.50	8.00%	11.00%	7.00%	Formula Result

Source: Commission staff calculations based on Dr. Booth's evidence. (Exhibit 78.02, pages 72-73).

54. The Commission notes that the ROE adjustment formula that was approved by the Commission's predecessor allowed ROE to fluctuate at 75 per cent of the change in interest rates. Table 3 above illustrates that, at a beta of 0.55 (as used in the 2004 Generic Cost of Capital Decision), the market risk premium implicitly changed inversely at 45 per cent of the change in interest rates. The use of the formula implies that the market risk premium is not constant.

55. The ROE adjustment formula proposed in this proceeding, based on the formula adopted by the Ontario Energy Board (OEB), would allow the ROE to change at 50 per cent of the change in interest rates. As Dr. Booth pointed out, this implies that with a beta of 0.50, and assuming no change in bond spreads, the market equity risk premium changes directly with the change in interest rates and that the market return is constant and does not change with interest rates. The Commission notes that, in sharp contrast to this, a formula based on a constant market equity risk premium would allow the Utility ROE to change at 100 per cent of the change in interest rates and would imply that the market equity return, far from being constant, would change at 100 per cent of the change in interest rates.

56. Based on the above observations about the implicit relationship of the market risk premium to interest rates that is embedded in the formulas that parties support, it does not appear that the market equity risk premium is constant or independent of the level of interest rates, which is what is implied when an historic equity risk premium is applied to today's low interest rates. This calls into question the use of long-term historic market equity risk premiums without regard to the current level of interest rates.

57. The Commission understands that actual long-term interest rates are near historic lows. At the Commission's estimated risk-free rate of 3.4 per cent to 3.8 per cent, the 30-year Government of Canada bond yield would be at the lower end of its historic range. In this circumstance, the Commission considers that it would not be correct to assume that the currently expected market equity risk premium is necessarily equal to its long-term average value.

58. Considering all of the above, the Commission finds that the expected market equity risk premium today may be higher than its' historic average, due to today's low interest rates. The Commission accepts that the market equity risk premium today may reasonably be as high as the 7.25 per cent mid-point of Ms. McShane's estimate.

59. The market equity risk premium from each expert's CAPM forecast is provided in Table 2 above. These range from 5.0 to 7.25 per cent. The Commission finds that a reasonable range for the market equity risk premium is 5.0 per cent to 7.25 per cent.

3.3.3 Beta

60. The next element of the CAPM analysis is the beta. Beta is a statistical measure describing the relationship of a stock's return with that of the stock market as a whole. In the Commission's view, the proper beta to use is that which represents the relative risk of stand-alone Canadian utilities. Past data (with or without adjustment) is usually used to estimate the reasonably expected beta going forward.

61. Ms. McShane used an adjusted beta to account for empirical studies that show that low beta stock returns would otherwise be under-estimated. Ms. McShane adjusted beta based on her own analysis of the adjustment required to explain historically achieved Canadian regulated company returns.[48] The Utilities proposed a beta in the range of 0.65 to 0.70.

62. The Utilities noted Ms. McShane's position that total risk, and not just diversifiable risk, should be considered for an undiversified investor, such as a utility investing in hard assets.[49] The Commission does not agree. The Commission's objective is to establish a market ROE for an investment of equivalent risk, held in a diversified market portfolio, because this emulates the conditions under which utilities raise equity capital.

63. The Utilities also noted that Dr. Fernandez (whose work had been cited by Dr. Booth) had provided evidence that the CAPM does not work and had concluded that historical betas are useless to estimate the expected return of companies.[50] However, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

64. The Utilities submitted that low risk utilities may not necessarily require a lower return than the overall market, when their higher financial leverage and risk is considered.[51] In the Commission's view, while a utility typically has higher financial leverage than a typical company on the stock market, it also has a correspondingly higher capacity for leverage due to its lower business risk. In the Commission's view, estimates of beta for utilities are estimates of utility risk relative to the market and already take into account the higher leverage of utilities.

[48] Exhibit 208, Utilities argument, paragraph 66.
[49] Exhibit 220, Utilities reply argument, paragraph 39.
[50] Exhibit 220, Utilities reply argument, paragraph 40.
[51] Exhibit 220, Utilities reply argument, paragraph 61.

65. Dr. Booth estimated that the Canadian stand-alone utility beta continues to be 0.45 to 0.55, the same range as he estimated in 2009. Dr. Booth based this conclusion on the performance of Canadian utility holding companies during the credit crisis, and the actual betas of low-risk U.S. utilities.[52]

66. Drs. Kryzanowski and Roberts submitted that a reasonable beta is 0.52. This was unchanged from their 2009 estimate and was based on observed betas.[53]

67. In 2009, the Commission found that a reasonable range for beta was 0.50 per cent to 0.63 per cent. Based on the 2011 evidence, the Commission is not persuaded to materially alter its finding from 2009. The Commission finds that a reasonable beta estimate is 0.50 per cent to 0.65 per cent.

3.3.4 Flotation allowance

68. The final element of the CAPM analysis is the flotation allowance. The parties all agreed 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. Historically, the Commission and its predecessors have allowed 0.50 per cent additional return on equity to account for the costs of flotation and to better ensure that the investor can expect to receive at least the required return.

69. In the Commission’s view, the flotation allowance also applies, for the same reasons, to the DCF method and all other estimates of the investor’s required return. The reason for this is that, if a utility has flotation or issuing costs which it cannot claim as regulated expenses, then the utility needs to earn more than the investors required return in order to cover these added costs.

70. Dr. Booth continued to apply the traditional 0.50 per cent flotation allowance.[54]

71. Drs. Kryzanowski and Roberts added the standard and traditional 50 basis points allowance. They explained that only 10 basis points were related to cost but added 40 basis points for flexibility based on common regulatory practice in Canada.[55]

72. Ms. McShane, for the Utilities, recommended a higher flotation allowance of 100 basis points to recognise the difference between the market value capital structures of proxy companies and the book value capital structures used by the Commission.[56]

73. The Utilities noted Ms. McShane’s evidence that the DCF and equity risk premium models represent conceptually different ways in which investors may approach estimating the return they require on the market value of an equity investment. She had submitted that, while the DCF and risk premium tests estimate the return required on the market value of common equity, regulatory convention applies that return to the capital invested in the book value of the

52 Exhibit 78, evidence of Laurence D. Booth, pages 56 and 57.
53 Exhibit 210, UCA argument, paragraph 54.
54 Exhibit 207, CAPP argument, page 19.
55 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 103.
56 Exhibit 209, Utilities argument, paragraph 83.

assets included in rate base. She submitted that the determination of a fair return on book equity needs to recognize that distinction.[57]

74. The UCA submitted that the Commission should continue to apply market returns to a book value rate structure in accordance with the 2004 Generic Cost of Capital Decision.[58]

75. The Commission does not agree with Ms. McShane's argument for increasing the flotation allowance above the historically allowed 0.50 per cent. Arguments that a market return should be applied to a market value based rate base, rather than a book value rate base, are circular since the market value is clearly dependent on the awarded return.

76. Accordingly, the Commission finds that the usual regulatory convention of awarding a flotation allowance of 0.50 per cent continues to be reasonable.

3.3.5 The Commission's resulting CAPM estimate

77. Applying its findings on the individual components of CAPM, the Commission calculated a range of CAPM ROE results for the required equity return for investors in stand-alone Canadian utilities of 6.4 per cent to 9.0 per cent.

Table 5. Commission's CAPM findings

Commission's CAPM Findings	Risk-free Rate	MERP	Market Return	Beta	Flotation Allowance	CAPM ROE
2011	3.4 % - 3.8%	5.0 - 7.25	8.40% -11.05%	0.50 -0.65	0.50	6.4% - 9.0%

3.4 Discounted cash flow model

78. The discounted cash flow model is used to estimate 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 rates. The DCF method calculates ROE as the rate of return that equates the present value of the estimated future stream of dividends with the current share price.

79. Parties applied the DCF method to both sample utility companies and to the market as a whole.

80. Ms. McShane, on behalf of the Utilities, provided a number of DCF estimates. She included DCF results for a sample of U.S. low-risk utilities as well as a sample of five Canadian utilities. These results used both analyst growth estimates and sustainable growth estimates (a calculation of growth based on ROE times the portion of earnings retained). She also provided both average and median results. The Commission focused on the average results because the median figures were internally inconsistent, given that the median dividend plus the median growth did not equal the median DCF result shown. Ms. McShane's DCF estimates were in the range of 8.5 to 9.5 per cent.[59]

81. In arguing for additional weight to be placed on DCF results, Ms. McShane compared it to the CAPM test. She submitted that the DCF test is a positive model that measures the expected returns actually available to investors. In contrast, she stated that the CAPM measures the cost of

[57] Exhibit 210, UCA argument, paragraph 84.
[58] Exhibit 210, UCA argument, paragraph 85.
[59] Exhibit 86.01, Kathleen McShane opinion, Schedules 16 and 17.

capital indirectly. In her view, DCF measures "what is" while CAPM estimates the required return on the market value of common stock on a "what should be" basis.[60]

82. Drs. Kryzanowski and Roberts applied the DCF method to the market as a whole and arrived at a return estimate for the overall equity market of 8.0 per cent.[61]

83. Dr. Booth stated that the DCF estimate of ROE for the Standard & Poor's (S&P) 500 utilities sub-index was 8.98 per cent.[62] Dr. Booth applied the DCF method to the Canadian equity market as a whole and found it indicated a required investor return of 8.2 to 8.4 per cent. This did not include a flotation allowance. Dr. Booth indicated that this represented a minor under-estimation due to current recession conditions and proposed that growth coming out of the recession would be higher.[63]

84. The following table sets out the individual DCF components and resulting ROE levels proposed by each of the parties that presented evidence on the DCF model.

[60] Exhibit 86.01, Kathleen McShane opinion, pages 75 and 43.
[61] Exhibit 210, UCA argument, paragraph 96.
[62] Exhibit 78, evidence of Laurence D. Booth, paragraph 153 CAPP Argument, page 20.
[63] Exhibit 78, evidence of Laurence D. Booth, paragraph 152.

Table 6. Summary of DCF estimates

Expert Witness	Dividend yield (%)	Stage 1 growth rate (%)	Stage 2 growth rate (%)	Final growth rate (%)	Investor required ROE (%)
DCF Applied to the Equity Market Overall					
Dr. Booth overall Canadian Market[64]	2.45			5.6 – 5.83	8.2 – 8.4
Drs. Kryzanowski and Roberts Toronto Stock Index using GDP estimates[65]	2.62 or 2.74			4.3, 4.83 and 5.20	7.09, 7.5, and 7.94
Drs. Kryzanowski and Roberts Toronto Stock Index using forecasts of pre-tax corporate earnings[66]	2.80				9.02, multi-stage growth 10.05 single stage growth
DCF Applied to Sample Utilities					
Dr. Booth S&P 500 utilities sub-index	5.01[67]			3.78[68]	8.98[69]
Ms. McShane U.S. utilities sample , average analyst constant growth estimates[70]	4.2			4.6	8.8
Ms. McShane U.S. utilities sample , calculated average sustainable growth[71]	4.2			4.9	9.0
Ms. McShane U.S. utilities sample , average three stage growth estimates (GDP growth for final stage) [72]	4.2	4.6	4.8	4.9	8.9
McShane Canadian utilities sample average analyst constant growth estimates[73]	3.8			5.7	9.5
McShane Canadian utilities sample average three stage growth estimates (GDP growth for final stage)[74]	3.8	5.7	5.1	4.6	8.5

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64 Exhibit 78, evidence of Laurence D. Booth, paragraph 152.
65 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, Schedule 2.4a, pages 38 to 39.
66 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, Schedule 2.4a, pages 38 to 39.
67 Exhibit 78, evidence of Laurence D. Booth, paragraph 153.
68 Exhibit 78, evidence of Laurence D. Booth, paragraph 153 (which incorrectly indicated 3.48 per cent) and Schedule 4 which indicated 3.78 per cent.
69 Exhibit 78, evidence of Laurence D. Booth, paragraph 153 (8.98 per cent is from 1.0378 times 1.0501).
70 Exhibit 86.01, Kathleen McShane opinion, Schedule 16.
71 Exhibit 86.01, Kathleen McShane opinion, Schedule 17.
72 Exhibit 86.01, Kathleen McShane opinion, Schedule 18.
73 Exhibit 86.01, Kathleen McShane opinion, Schedule 19.
74 Exhibit 86.01, Kathleen McShane opinion, Schedule 20.

85. In 2009, the Commission rejected the use of long-term or terminal growth rates for utilities that exceed estimates of nominal dollar GDP growth. For 2011, there was no indication that the terminal growth rate forecasts exceeded reasonable estimates of nominal GDP growth.

86. In 2009, the Commission expressed concern about the potential upward bias in analysts' growth estimates.[75] However, Ms. McShane argued that, as long as investors believe the optimistic forecast, they would price the securities lower (resulting in a lower dividend yield) and the DCF test would still be an unbiased estimate of investor required returns. She indicated that this proposition had been successfully tested and described three tests, including the fact that such growth estimates have averaged less than GDP growth.[76] In the Commission's view, this line of reasoning does not resolve the issue because there is no evidence that investors believe optimistic forecasts. Therefore, the Commission remains concerned with the potential upward bias in analysts' growth estimates.

87. In 2009, the Commission also expressed concern about using proxy companies in a DCF analysis that are utility holding companies engaged in significant unregulated activities.[77] The Commission notes that Ms. McShane's Canadian sample consists of Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc. and TransCanada Corp. Of these, the Commission continues to consider only Emera Inc. and Fortis Inc. to be relatively free of unregulated activities. The Commission notes that the DCF results were 9.3 per cent for Emera Inc., using the three stage estimate, and 8.8 per cent for Fortis Inc., also using the three stage estimate.

88. The results above appear to suggest that investors expect a return of about 9.0 per cent on utility investments, assuming investors agree with analysts' growth forecasts. The Commission also notes that the DCF applied to the overall market suggested returns in the range of 7.1 to 10.1 per cent.

89. As explained above, the Commission considers that the DCF results should be adjusted to include flotation costs. As with the CAPM analysis, the Commission has adjusted the DCF results to include a 0.50 per cent flotation allowance

90. Overall, the Commission finds the 2011 results of the DCF analyses presented in the proceeding suggest a range of allowed ROEs for Canadian stand-alone utilities of 8.8 to 9.5 per cent, assuming that the equity ratio has been set to target a credit rating in the A range. However, as noted above, the Commission remains concerned about the potential impact of optimistic growth forecasts in this result.

3.5 Market returns on comparable investments

91. In AUC-ENGEN-09 (Exhibit 138), Mr. Engen provided data for certain Canadian energy infrastructure companies and included the price/earnings (P/E) ratios, the dividend yield, the price-to-book ratios and the ROEs. The median company in this group had a P/E ratio of 21.1, which equates to an earnings yield of 4.7 per cent. The median dividend yield was 5.2 per cent, which, because it is higher than the earnings yield, indicates that more than 100 per cent of the accounting earnings were being paid out, for the median company. The median price-to-book ratio was 2.1 times and the median ROE was 10.5 per cent. The Commission recognizes that

[75] Decision 2009-216, paragraph 269.
[76] Exhibit 86.01, Kathleen McShane opinion, page 77, lines 1843-1850.
[77] Exhibit 86.01, Kathleen McShane opinion, page 77, lines 1843-1850.

infrastructure companies may also be able to pay out cash flows from depreciation and future income taxes that are in excess of earnings (at least temporarily, until long-lived assets need to be replaced).

92. The UCA submitted that Mr. Engen's evidence on certain Canadian energy infrastructure firms showed price-to-book values well in excess of 1.0, with the median and mean P/E ratios over 20, implying an earnings yield of five per cent. The UCA acknowledged that this did not account for growth and was not necessarily indicative of an appropriate allowed ROE, but submitted that it did indicate that investors in these shares were content with the firms having earnings yields in the range of five to six per cent of their market values which, it submitted, suggests that the required returns for utility investors are nowhere near the levels proposed by Ms. McShane.[78]

93. In the Commission's view, it is possible that part of the reason for the high P/E ratios is that, similar to the case with bonds, the higher prices and lower earnings and cash yields are an indication that the market required return has fallen. Another possibility is that investors expect to ultimately receive substantially more than the median earnings yield of 4.7 per cent and more than the median cash yield of 5.6 per cent, due to growth. However, with more than 100 per cent of the earnings being paid out in dividends, the sustainable growth formula (growth equals ROE times the proportion of earnings retained) would suggest that there will be minimal or no growth. Investors may still have legitimate expectations for growth, perhaps based on past experience. The sustainable growth formula assumes a constant ROE and does not take into account the ability to issue new shares and invest that money on an accretive basis. It also does not account for the fact that these infrastructure companies (with long-lived assets) may be able to invest some of the depreciation cash flows and future income tax cash flows to fund growth. Ultimately, however, one would assume that depreciation cash flows will be needed to replace existing assets.

94. In the Commission's view, the data provided by Mr. Engen on Canadian infrastructure companies does not provide much support for the case that investors should reasonably expect to earn double digit returns in these investments. It would require growth in the range of 4.8 per cent annually (added to the dividend yield of 5.2 per cent) to arrive at a 10 per cent expected return. With more than 100 per cent of the earnings being paid out as dividends, it is not clear where earnings growth beyond the rate of inflation would come from.

95. Overall, the Commission finds that the evidence is inconclusive on the return investors expect on these infrastructure companies, and there is insufficient evidence that these returns are sufficiently comparable to the utility investments at issue in this proceeding.

3.5.1 Historic returns

96. In her evidence, Ms. McShane examined the historic returns for utilities. According to Ms. McShane, the historical average utility return, in both Canada and the U.S., has clustered in the 11.0 to 12.0 per cent range. She submitted that investors tend to base their expectations on experienced returns and that there was no long-term upward or downward trend. She submitted that the utility returns had varied by approximately 50 per cent of the change in long-term government bond yields.

[78] Exhibit 210, UCA argument, paragraph 103.

97. Ms. McShane also used this historical data on the experienced returns of utilities to provide an additional equity risk premium estimate derived from the observed equity risk premiums achieved by utilities. This resulted in an equity risk premium of 6.25 to 6.5 per cent. At Ms. McShane's forecast Canada bond yield of 4.25 per cent, the indicated utility cost of equity was approximately 10.50 to 10.75 per cent or 11.5 to 11.75 per cent after adding her recommended 1.0 per cent for flotation.

98. The UCA noted that Ms. McShane had provided evidence indicating that utility investors have made returns that are higher than the overall market and stated that, at best, this was evidence that regulators have over-estimated the risk-adjusted cost of equity (and thereby provided a return that is too high).[79]

99. The Commission agrees with the UCA that part of the reason for higher historic returns may be that allowed returns have been above the actual ROE that investors expected and required for investments of comparable risk. The Commission finds that the evidence on historic returns is inconclusive with respect to the return investors expect on comparable investments.

3.6 Returns awarded by other regulators

100. The Utilities submitted that the mean and median equity returns allowed by Canadian utility regulators, excluding Alberta, are 9.62 per cent and 9.66 per cent, respectively. The Utilities noted that some of these returns involved negotiated settlements but they argued that the results from a range of negotiated settlements provide insight as to reasonable returns.[80] The Utilities submitted that this comparison indicates that the current ROE of 9.0 per cent is too low.

101. The Commission notes that these awarded returns range from 8.38 per cent for Newfoundland Power for 2011 to 10.15 per cent for Pacific Northern Gas–West for 2011. The Commission also notes that these awarded returns would have pre-dated the drop in interest rates that occurred in August 2011 and may have reflected premiums for the 2008-2009 credit crisis.

102. The Commission also gives no weight to the equity returns arising from negotiated settlements. The Commission recognizes that, in a negotiated settlement, there are various trade-offs to which parties have agreed that can skew the awarded ROE.

103. Accordingly, the Commission gives no weight to the returns awarded by other regulators and included on the record of this proceeding.

3.7 Price-to-book ratios

104. An equity price-to-book ratio (also called market-to-book ratio) is calculated by dividing the current market price of a stock by its current book value per share. It is often used to compare a stock's market value to its book value. There was considerable debate during the proceeding as to the relevance, if any, of price-to-book ratios.

[79] Exhibit 210, UCA argument, paragraphs 104 and 105.
[80] Exhibit 209, Utilities argument, paragraphs 101-103.

105. The Utilities provided a variety of arguments as to why price-to-book ratios of utility holding company shares and those derived from the acquisitions of utilities are not indicative of required returns or the cost of capital.[81]

106. In regards to the price-to-book value of the 2001 AltaLink transaction, the Utilities referred to AUC-ENGEN-07. In that response, Mr. Engen indicated that the price-to-book value at the time of the purchase was 1.93. He also indicated that subsequent additional investments by AltaLink (which are made at book value) have reduced the ratio to 1.26. However, the Commission notes that this 1.26 estimate is not calculated as the current value of AltaLink divided by its current book equity and does not appear to be a relevant figure.

107. In his rebuttal evidence, Dr. Booth provided an appendix of basic financial relationships and stated "[i]f a Board then accepted a high market-to-book ratio in any way, it is implicitly indicating that it is awarding an unfair allowed ROE and is being derelict in the exercise of its statutory responsibilities." He noted that an exception is to allow a ratio slightly above 1.0 to prevent dilution on a share issue.[82]

108. Dr. Booth stated that the observed price-to-book ratios indicate allowed returns have generally been higher than the fair return. CAPP submitted that the bidding war for Central Vermont Power resulted in an equity price-to-book ratio at or above 2.0. CAPP also noted that AltaLink itself indicated a price-to-book ratio of 1.58 regarding the 2011 sale of a portion of AltaLink.[83]

109. In their evidence, Drs. Kryzanowski and Roberts indicated the ROE for Fortis Inc. (which they indicated was the only Canadian relatively pure-play utility, considered by the Commission in 2009, that trades on the market) is generous because Fortis Inc.'s price-to-book ratio is well above 1.0, despite substantial intangible assets (goodwill), indicating the ROE is above the cost of equity.[84] They submitted that high utility price-to-book values in the U.S. mean the utility returns on market value have been single digit. They also submitted that the recent AltaLink transaction, involving the purchase by the SNC-Lavalin Group Inc. of the minority interest in AltaLink, represents a low ROE for the purchaser.

110. The UCA submitted that there did not appear to be any dispute that, in theory, a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true cost of capital. The UCA also submitted that another fact that did not seem to be in dispute was that the actual market-to-book ratios for utility shares, and in utility purchase transactions, are almost always considerably higher than 1.0.[85] The UCA submitted that the fact that the observed market-to-book ratios are so significantly above 1.0 strongly suggests that prevailing allowed returns are too high, and probably by a considerable amount.[86]

111. The UCA submitted that utility shares trade in the market at a value almost twice the book value of utility assets.[87] The UCA noted that Drs. Kryzanowski and Roberts had estimated the price-to-book value of the 2011 AltaLink transaction to be 1.95, with goodwill included in

81 Exhibit 209, Utilities argument, paragraphs 106-113.
82 Exhibit 145.01, update and rebuttal evidence of Laurence D. Booth, page 44.
83 Exhibit 207, CAPP argument, paragraphs 57 and 58.
84 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 15.
85 Exhibit 210, UCA argument, paragraphs 108 and 109.
86 Exhibit 210, UCA argument, paragraph 119.
87 Exhibit 210, UCA reply argument, paragraph 53.

the book value, and 3.39 with goodwill excluded.[88] The Commission considers that the relevant price-to-book value for a pure-play regulated utility with no unregulated business is the price to the book value of the portion of rate base supported by equity, which would exclude goodwill from book value since goodwill is not allowed in rate base.

112. Decision 2009-216 stated that:

> The Commission considers that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios for utility holding companies.
> …
> The (equity) price-to-book ratio for the 2007 Fortis acquisition of Teresen Inc. was discussed on the record of the proceeding as a potential indicator of the price-to-book ratio for a stand-alone utility. However, there was considerable disagreement as to the correct calculation of the price-to-book value for this transaction. Price-to-book values in the range of 1.27 to 3.99 were provided. Despite the lack of agreement with respect to the exact calculation, the evidence is that the price paid for Teresen Inc. was at a price-to-book ratio above 1.2. It appears therefore that the awarded return for Teresen was at least fair, at the time of the transaction. However, there is ample evidence on the record that conditions in the market have changed significantly since the Teresen transaction in 2007, and the Commission cannot rely on this transaction as indicative of a fair return for 2009.[89] (footnotes omitted)

113. The Commission notes the evidence that pure-play regulated Canadian utility assets have historically been valued at equity price-to-book value ratios significantly above 1.0, including the 2011 AltaLink transaction, the 2007 Fortis Inc. purchase of Terasen Inc., the 2004 Fortis Inc. purchase of Aquila (referenced in Decision 2004-052[90]) and AltaLink's 2001 purchase of the transmission assets of TransAlta.

114. In Decision 2009-216, the Commission indicated it could not rely on such transactions, specifically the 2007 Terasen transaction, as being indicative of a fair return for 2009. The situation in 2009 was that, during the credit crisis, stock markets declined substantially, and it was clear that the higher levels of price to book ratios observed in the above transactions, would have declined during the credit crisis. The subsequent 2011 AltaLink transaction following the recovery in stock market prices may be evidence that pure-play regulated Canadian utilities are once again valued at high price-to-book ratios. The question then becomes; do high price-to-book ratios indicate that regulated returns have been above the market required level?

115. The Commission's predecessor indicated in Decision 2004-052 that strategic factors, growth and geographic diversification might explain the payment of a premium. There was some debate in this proceeding on the reasons why investors have been willing to pay significant premiums to purchase pure-play regulated utility assets.

88 Exhibit 210, UCA argument, paragraph 120.
89 Decision 2009-216, paragraphs 295 and 297.
90 Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd, ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd., Application No. 1271597, July 2, 2004.

116. Mr. Engen proposed that the opportunity for cross-border purchasers to deduct the same interest in two countries may explain the premiums. Dr. Booth noted, and the Commission agrees, that in the transactions referenced above there were no cross-border purchasers involved. Mr. Engen proposed that the value of expected growth in rate base assets may encourage a premium. However, Dr. Booth submitted that financial theory indicates that growth is of value only if the expected ROE exceeds the fair rate of return. The Commission agrees with this. If there were ample opportunities to invest at the same or higher returns elsewhere, then the opportunity to grow rate base has no value.

117. Mr. Engen offered that a premium may signal an expectation of higher regulated return levels in the future. Dr. Booth submitted that, if this were the case, it would suggest that the current return was too low and accordingly the current price-to-book ratio should be below one. The Commission agrees.

118. Mr. Engen argued that a premium may be paid if investors expected that operating efficiencies would lead to higher earnings. Dr. Booth submitted that, under regulation, cost savings are meant to be passed on to customers. However, the Commission recognizes that, under the current rate base rate of return regime, operating savings can result in earnings beyond the regulated return and investors are entitled to retain these earnings during a test year. This provides incentives for increased efficiencies, but these efficiencies are later realized by customers in the next test period. The Commission is also aware that many of the utilities it regulates frequently achieve operating efficiencies and earn returns beyond the allowed return.

119. Likewise, Mr. Engen suggested that performance-based regulation (PBR) opportunities may have incented investors to pay a premium. Dr. Booth submitted that this was partly correct, but that a price-to-book ratio of 1.8 would require very large, if not impossible, efficiencies. The Commission agrees that the opportunity to adopt performance based regulation may be a justification for a premium, given that the opportunity to retain earnings above the regulated return is enhanced under PBR.

120. Finally, Mr. Engen argued that access to attractive unregulated assets and collateral benefits or synergies, or access to new territory, or a desire to protect one’s existing regulated franchise may be reasons to pay a premium. The Commission agrees that these may arguably be business reasons for the payment of a premium.

121. In the Commission’s view, it would not be rational for investors to purchase a utility at a premium, unless it was of the view that it could earn at least a market rate of return on the investment despite paying the premium. The payment of premiums in such transactions for assets that are earning returns based on ROE awards that are allegedly below market would not appear to be rational. A possible conclusion is that such purchases, at substantial premiums, would indicate that the awarded returns were more than sufficiently attractive.

122. Again, the Commission finds, as it did in Decision 2009-216, that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios of utility holding companies. With respect to the recent AltaLink purchase by the SNC-Lavalin Group Inc., given the above discussion, the Commission considers that there may be business reasons for this purchase that are not well understood. In these circumstances, it is difficult for the Commission to draw any

conclusions about the significance of this transaction to the establishment of a fair return on equity. Nonetheless, the Commission agrees with the observation that a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true cost of capital. Estimates of the price to book ratio for the 2011 AltaLink transaction generally exceed 1.0 by a significant margin. This appears to be evidence that the allowed ROE at the time of the purchase was at least adequate.

3.8 Returns available on high grade corporate bonds

123. CAPP referenced the fact that in Decision 2009-216, the Commission concluded that the high corporate bond spreads at that time justified the addition of 50 basis points to the results derived from methodologies like CAPM that rely solely on historical data to estimate the equity premium above the risk free rate.[91]

124. Dr. Booth indicated that studies by the Bank of Canada have shown that 63 per cent of the increase in corporate spreads during the credit crisis was due to liquidity problems in the bond market and only 37 per cent was due to default risk. He argued it is only the default risk that affects equity investors.[92] Dr. Booth indicated that, in contrast to corporate bond liquidity, equity market liquidity had increased during the credit crisis and equity investors should not be rewarded for a liquidity problem in the bond markets that does not affect equity holders.[93]

125. Dr. Booth saw a justification for no more than 25 basis points at this time, in respect of higher than historical corporate bond spreads, but used a range of 25 to 50 basis points for this allowance.

126. The Utilities submitted that spreads on Canadian A-rated utility bonds, as at July 29, 2011, were at 141 basis points, which is well above the 95 basis point average for 2003 through 2007.[94]

127. In Decision 2009-216, the Commission stated:

> As has occurred throughout this Proceeding, the Commission must weigh conflicting expert testimony on various factors impacting the determination of a fair return for Alberta utilities. The Commission considers the increased high grade Canadian corporate bond spreads which occurred during the financial crisis and which continued to occur, albeit on a downward trend, at the close of the Proceeding demonstrate that there has indeed been some re-pricing of risk on debt securities. Equity investors in high grade rated companies have more default risk than do debt investors. An increase in debt investor return expectations ordinarily must be considered to result in an increase in return expectations for equity investors otherwise equity investors would not accept the incremental risk associated with equity ownership. The Commission finds that there is insufficient evidence on the record of the proceeding that illiquidity in the Canadian bond market during the financial crisis can account for a significant portion of the increased risk premium demanded by bond investors.
>
> It remains an open question whether corporate bond spreads will quickly, if ever, return to pre-financial crisis levels. In particular, it remains uncertain that the re-pricing of risk

[91] Exhibit 207, CAPP argument, paragraph 61 referencing Decision 2009-216 at paragraph 311.
[92] Exhibit 207, CAPP argument, paragraph 64.
[93] Exhibit 207, CAPP argument, paragraph 70.
[94] Exhibit 209, Utilities argument, paragraph 23.

> observed in high grade Canadian corporate bond spreads in the period up to the close of the Proceeding will end in either 2009 or 2010. In these circumstances, it is reasonable to conclude that the actual return expectations of utility equity investors in 2009 and 2010 would be at least 50 basis points higher than estimates of equity return expectations derived from methodologies like CAPM which rely solely upon historical data and the risk free rate.

128. As discussed in Section 3.2 above, the Commission considers that spreads have decreased from the 2009 levels but have not returned to their historic levels. The Commission also notes that it has set the top end of its CAPM market equity risk premium, assuming, on the basis of Ms. McShane's evidence, that the market equity risk premium may be higher than its historic average at this time of historically low interest rates. For these reasons, the Commission is not convinced that any addition to CAPM results is needed to account for the reduction in corporate bond spreads at this time.

3.9 Pension, investment manager and economist return expectations

129. In regards to the return expectations of pension and investment managers and others, the UCA submitted that, in December 2010, CIBC World Markets had forecast total returns on the Canadian market of 8.0 to 9.0 per cent over the next decade. In addition, the UCA submitted that BMO Capital Markets had recently forecast an equity market return of 6.5 to 7.2 per cent, with a market equity risk premium of 3.5 to 4.2 per cent and, that the mid-point of estimates from Fiduciary Trust Company of Canada for the equity market return and market equity risk premium (relative to yields on 10-year Government of Canada bonds) were eight per cent and five per cent, respectively. The UCA also submitted that, in Mercer's 2011 Fearless Forecast survey of Canadian and global institutional investment managers, the median expected return for the TSX Composite is 8.5 per cent. The 2011 Towers Watson survey results, which show participants' expectations for the TSX Composite Index return in the short, medium and long-term, indicated that the median or 50th percentile short-term expectation for 2011 was eight per cent, with the median medium and long-term expectations below eight per cent.[95]

130. Drs. Kryzanowski and Roberts and Dr. Booth also referred to, and summarized, the results of surveys conducted by Drs. Fernandez and del Campo of forward-looking estimates of the market equity risk premium and total equity market returns by academics, financial professionals, and corporate finance executives. The UCA submitted that, as these surveys show, the mean and median forward-looking market equity risk premium estimates are in the low five per cent range, with academics generally providing the highest estimates. The estimates declined from 2009 to 2010.[96] The Commission notes that using a risk-free rate of 3.4 to 3.8 per cent, this would imply market returns in the range of eight to nine per cent.

131. Drs. Kryzanowski and Roberts also described surveys of U.S. chief financial officers conducted by Drs. Graham and Harvey concerning expected returns on the S&P 500. They summarized the results of a series of such surveys in their Schedule 2.9.3.2a, which shows an average expected overall market return of less than 7 per cent for the most recent periods and expected market equity risk premiums for those periods of 3 per cent or less.[97]

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95 Exhibit 210, UCA argument, paragraph 122.
96 Exhibit 210, UCA argument, paragraph 123.
97 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, Schedule 2.9.3.2a.

132. The Utilities submitted that survey results do not provide a reliable basis for estimating the cost of capital because they do not provide supporting quantitative analysis and do not indicate whether the results are in the nature of a geometric or arithmetic average. The Utilities also stated that corporations making investment decisions were using hurdle rates of 14 per cent at a time when the 10-year Treasury yield was four per cent.[98]

133. The Commission finds that the evidence provided by interveners suggests that pension, investment manager and economist return expectations for the market are in the eight per cent range.

3.10 Impact of growth on required ROE

134. The UCA submitted that, in principle, it was not persuaded that the potential for growth should be a factor in determining an appropriate ROE. If the allowed ROE is set equal to the risk-adjusted cost of capital for utility investments, investors should be indifferent as between utility investments and the alternatives available in the market. If it is established that the potential for growth is a highly attractive attribute for utility stocks, this suggests that the allowed ROEs are generous. The more enthusiastic utilities and utility investors are about potential growth, the stronger the implication that allowed returns exceed the true cost of equity.[99]

135. The Utilities submitted that growth is attractive and that it could result in a reduction of existing price-to-book ratios over time, but that growth does not suggest a lower ROE should be approved. The Utilities submitted that extremely large growth can result in increased financial risk.[100]

136. The Commission acknowledges that investors should, in theory, be indifferent to growth if growth is only expected to provide a risk-adjusted return readily available elsewhere in the market. The Commission notes that growth in utilities requires additional earnings to be retained rather than paid out as dividends or may require the injection of equity for which the investor will only receive the allowed ROE. In general, the intervener experts appeared to view their ROE recommendations as being somewhat generous. Ms. McShane submitted the ROE should be above the bare bones cost.

137. In addition, the Commission notes the evidence of Mr. Engen who submitted that growth in earnings per share (EPS) is what is important to investors[101] and that EPS accretion is widely used and accepted by the investment community as an important rationale in justifying acquisitions. He submitted that whether, and under what circumstances, financial theory would or would not support the view that EPS accretion increases value is not relevant to whether the EPS accretion is used in practice to support acquisitions.[102]

138. In the Commission's view, it is reasonable to conclude that investors value growth only if the expected growth provides the necessary return. Investors might accept a somewhat lower expected and awarded ROE for a high-growth utility, as compared to a low-growth utility, but only if they expect that the utility will be able to earn in excess of its awarded ROE.

98 Exhibit 220, Utilities reply argument, paragraph 69.
99 Exhibit 210, UCA argument, paragraph 128.
100 Exhibit 209, Utility argument, paragraphs 118-121.
101 Exhibit 86.01, evidence of Aaron M. Engen, page 10, lines 18 and 19.
102 Exhibit 152.01, rebuttal evidence of Aaron M. Engen, paragraph A24.

3.11 The Commission's awarded ROE

139. The Utilities requested an ROE of 10.375 per cent based on the expert evidence of Ms. McShane.

140. Dr. Booth's position was that no Alberta utility had difficulty raising capital since the last generic cost of capital proceeding and that no increase in ROE is warranted. If anything, the ROE should be reduced.

141. The UCA submitted that the fair ROE is in the range of 8.0 to 8.5 per cent and the Commission should approve an ROE not higher than 8.3 per cent.[103]

142. The CCA accepted the ROE recommendation of Drs. Kryzanowski and Roberts of 8.3 per cent for 2011and recommended that the Commission approve an ROE of 8.4 for 2012.[104]

143. In this decision, the Commission has set out to establish a fair rate of return on equity for 2011 and going forward for the utility companies it regulates. The awarded ROE must be based on an estimate of the risk-adjusted opportunity cost of equity capital. The Commission must estimate the return on equity that utility investors are foregoing by having their equity invested in these utilities rather than in other investments of similar risk that are available in the market. The difficulty that the Commission faces is that the ROEs that are available to be earned on investments of similar risk are not directly observable.

144. In keeping with the Commission's determinations above, the Commission will establish a generic ROE to be applied to each of the utility businesses it regulates as if they were stand-alone utilities. The Commission has reviewed the models and approaches adopted by the various parties and, based on the analyses above, has found that some of the CAPM and DCF results filed in this proceeding (including an analysis of the expected overall Canadian stock market returns) will form the primary basis for its ROE determination.

145. In making its ROE determination, the Commission is mindful of the uncertainties created by the financial crisis that began in the third quarter of 2007 and its lingering effects, which have not fully abated. The Commission found that, by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels.

146. The Commission found that a reasonable CAPM estimate is in the range of 6.4 to 9.0 per cent based on its analysis of the forecast risk free rate, the market equity risk premium and beta.

147. The Commission also found that the DCF results suggest a range of ROEs for Canadian stand-alone utilities of 8.8 to 9.5 per cent, assuming the equity ratio has been set to target a credit rating in the A range. The Commission concludes that the DCF results appear to suggest that investors expect a return of about nine per cent on utility investments, assuming investors agree with analysts' growth forecasts. However, as noted above, the Commission remains concerned about the impact of optimistic growth forecasts in this result. This concern is bolstered by the results of the DCF analysis applied to the overall market which suggested returns in the range of 7.1 to 10.1 per cent.

103 Exhibit 210, UCA argument, paragraph 138 and 149.
104 Exhibit 211, CCA argument, paragraphs 32 and 77.

148. The evidence provided by interveners suggests that pension, investment manager and economist return expectations for the market are in the eight per cent range.

149. Having considered and weighed all of the evidence and assessed it in the context of the lingering credit market volatility, and recognizing that there has been a reduction in the risk free rate of some 60 basis since 2009 by the close of the record of this proceeding, the Commission finds that some reduction in the ROE awarded in Decision 2009-216 is warranted. Accepting that some of the reduction in the risk free rate may be offset by an increase in the market equity risk premium, the Commission considers that a generic ROE of 8.75 per cent is reasonable for 2011.

4 Return to the formula adjustment in 2012

150. Having determined the generic rate of return on equity for 2011, the Commission must consider how that rate of return will be adjusted in future years. One of the principal purposes of this proceeding has been to consider whether the annual adjustment formula approach discontinued in 2009 should be reinstated and if so, what type of formula for annual adjustments to ROE should be adopted by the Commission.

151. In Decision 2004-052, the Commission's predecessor, the Alberta Energy and Utilities Board (EUB or Board) adopted the annual adjustment formula for setting the generic ROE based on 75 per cent of the change in long Canada bond yields:[105]

$$ROE_{New} = \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield})$$

152. This formula was discontinued in Decision 2009-216, because of the economic crisis conditions observed at the time of the 2009 GCOC proceeding. Specifically, the Commission concluded that the historical relationships upon which the formula was based had not yet been re-established in the aftermath of the financial crisis.[106]

153. In this proceeding, the Utilities recommended that the Commission not adopt an automatic adjustment formula at this time for two reasons. First, the Commission's performance-based regulation (PBR) initiative for distribution utilities could change the risk profile of the distribution utilities and may require the re-evaluation of the fair ROE. Second, as outlined in Section 3.2 above, the Utilities argued that there remained considerable risk in the global economy and capital markets.[107]

154. However, the Utilities submitted that, if the Commission determined that an automatic adjustment mechanism is warranted for 2012, the formula adopted by the OEB in its Report EB-2009-0084 should be used. The OEB formula is as follows:

$$\begin{aligned} ROE_{New} = {} & \text{Initial ROE} + 50\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ & + 50\% \times (\text{Change in utility bond yield spread}) \end{aligned}$$

155. The Utilities indicated that Ms. McShane's independent analysis supported the factors and weightings used in this formula, based on the historical relationships among the utility cost of equity, long-term government bond yields and corporate bond yield spreads.

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105 Decision 2004-052, page 32.
106 Decision 2009-216, paragraphs 418-420.
107 Exhibit 209, Utilities argument, paragraphs 122.

156. The UCA witnesses, Drs. Kryzanowski and Roberts, agreed that the formula adopted by the OEB reflects an appropriate adjustment structure. The UCA's position was that the Commission should return to a formula approach to setting allowed ROEs on a generic basis for the Alberta utilities because of the practical advantages resulting from regulatory efficiency. The UCA submitted that a properly designed ROE formula provides reasonably accurate estimates of the true cost of equity over a reasonable period.

157. Based on their opinion that credit markets had normalized, Drs. Kryzanowski and Roberts did not share the Utilities' view that the return to a formula would not be beneficial at this time. Furthermore, the UCA witnesses pointed out that introducing a utility bond spread component will mitigate any remaining concerns as to the financial market volatility.[108] With respect to the Utilities' concerns related to the ongoing PBR proceeding, the UCA expressed the opinion that the PBR may not involve any material changes in business risk. Additionally, the UCA indicated that one would expect changes in business risk to be addressed through capital structure adjustments rather than ROE adjustments, in accordance with past practice in Alberta.[109]

158. Dr. Booth, testifying on behalf of CAPP, proposed a modified formula that reflects 75 per cent of the change in the Government of Canada long bond yield and 50 per cent of the change in utility bond spreads:

$$\begin{aligned} ROE_{New} = {} & \text{Initial ROE} + 75\% \times (\text{Change in forecast 30-year GOC bond yield}) + \\ & + 50\% \times (\text{Change in utility bond yield spread}) \end{aligned}$$

159. Dr. Booth explained that the 75 per cent adjustment factor is consistent with the formula that the Commission and its predecessor used between 2004 and 2009, and is supported by his analysis of market and utility risk premia.[110] By contrast, CAPP submitted that the formula proposed by Ms. McShane, with the 50 per cent adjustment factor for the Government of Canada long bond yield, would imply ROEs higher than those determined by regulators in that time period, including this Commission's predecessor.

160. CAPP also pointed out that the Quebec Régie de l'Energie accepted Dr. Booth's modified formula in a recent Gazifere decision (D2010-147) and will use it beginning in 2012.

161. The CCA indicated that none of the formulae proposed in this proceeding appear to be based on any financial analysis as to their validity and submitted that it prefers the Commission not return to an adjustment formula but periodically set a generic ROE.[111]

Commission findings

162. In Decision 2009-216, the Commission observed that due to the then-existing credit crisis conditions, the relationships among various market indicators were not stable and decided not to employ an adjustment formula for 2010. As discussed in Section 3.2 above, the evidence in this proceeding demonstrated that, although there has been some improvement in the financial environment, credit markets remain volatile. Referring to the financial community's concerns with the European sovereign debt, Dr. Booth summarized this view as follows:

[108] Exhibit 210.02, UCA argument, paragraph 16.
[109] Ibid., paragraph 21-22.
[110] Exhibit 78.02, evidence of Laurence D. Booth, paragraphs 180-184.
[111] Exhibit 211, CCA argument, paragraph 21.

> The fact is that we don't know all of the linkages in the credit default swap market, so that is a palpable nervousness in the bond market. That is something that is highly unusual. It is still there. It is nowhere near as bad as it was three years ago, but it is there, and we do not have a normal market.[112]

163. As the Commission explained in Decision 2009-216, the 2004 formula was developed based on the expectation that the required rate of return for utilities moves in the same direction as the return on 30-year Government of Canada bonds. The Commission found that, during a time of adverse market conditions, this expected relationship between interest rates and the required return on equities does not necessarily hold.[113]

164. All parties to this proceeding preferred a formula that considered both changes in Government bond yields, and changes in utility bond spreads. The Commission agrees that this type of formula will better reflect any fluctuations in financial market conditions and deal with the concerns about a single variable formula. Moreover, as Dr. Booth's explained, such a formula would be counter-cyclical because allowed returns would increase in difficult economic times and decrease in strong economic times, but over the business cycle this will average out.[114]

165. The Commission agrees with the interveners' arguments that a modified formula that accounts for changes in corporate bond spreads partially corrects for the drawbacks of a single-variable formula. Nevertheless, the Commission has considered the evidence of continuing credit market volatility and finds that a return to the formula mechanism for annual adjustments to ROE is not warranted at this time.

166. Accordingly, the Commission will not employ an adjustment formula for 2012. At the same time, as noted in the Decision 2009-216, the Commission is not prepared to preclude a return to some form of formula-based adjustment mechanism in the future, once the capital markets have stabilized and are once again considered reasonably predictable.[115] As such, the Commission is prepared to revisit the re-introduction of an automatic adjustment mechanism once the credit markets are more predictable and the Commission can be confident that the relationships implied in the formula will continue.

167. As explained in Section 3.11 of this decision, the Commission has determined that a fair generic rate of return on equity for Alberta utilities for 2011 is 8.75 per cent. Given the December 8, 2011 issue date of this decision and the fact that the record closed on September 9, 2011, the Commission is mindful of the proximity of this decision date to 2012. Considering the substantial drop in interest rates by the close of the record, the Commission sees no reason to find that the risk free rate of 3.4 to 3.8 per cent that it has accepted as reasonable for 2011 would not also be reasonable for 2012. The Commission does not consider that adjustments to any of its other findings with respect to the establishment of a reasonable ROE for 2011 are warranted for 2012. Accordingly, the Commission concludes that an ROE of 8.75 per cent is fair for both 2011 and 2012.

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112 Transcript, Volume 7, page 911, lines 8 to 13.
113 Decision 2009-216, paragraphs 417 and 418.
114 Exhibit 207.02, paragraph 97.
115 Decision 2009-216, paragraphs 420-422.

168. In addition, the Commission is setting the allowed ROE for 2013 at 8.75 per cent on an interim basis. The Commission will initiate a proceeding in due course to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula for setting the allowed ROE on a go forward basis. The Commission considers that establishing an allowed ROE for 2012 and setting an interim ROE for 2013 will provide for a more supportive, and predictable regulatory environment.

5 Capital structure matters

5.1 Introduction

169. To satisfy the fair return standard, the Commission is required to determine a capital structure (equity ratio) for each of the utilities that are the subject of this proceeding. In this decision, the Commission has established a generic ROE of 8.75 per cent which will be applied uniformly to all of the utilities. Consistent with the approach taken in the previous GCOC decisions, the Commission will account for the differences in risk among the individual utilities by adjusting their capital structures.

170. As the Commission noted in Decision 2009-216, in general, the return required by investors on debt is lower than the return required on equity. This is because debt holders have priority over equity holders in the distribution of earnings from operations and, in the event of bankruptcy, in the disposition of the assets of the firm. As the proportion of debt in the capital increases, a greater portion of the earnings from operations of the firm are required to cover the increased interest costs on debt. Therefore, as the proportion of debt rises, both debt and equity investors will perceive an increase in risk: debt holders will be concerned that the debt obligations of the firm may not be met, and equity investors will be concerned that there will be insufficient earnings from operations to both cover the debt obligations of the firm and pay them their expected return.

171. This risk is usually assessed by various interest coverage calculations that measure the ability of the firm to pay its debt obligations. Bond rating agencies, such as Standard & Poor’s (S&P) and DBRS Limited (DBRS) assess the risk of individual firms on the basis of various interest coverage metrics and an overall assessment of the risk that the firm will not be able to cover its debt obligations.

172. In this decision, the Commission will establish the capital structure for each utility that, in the Commission’s judgment, would allow a stand-alone utility to maintain a credit rating in the A range, subject to company-specific circumstances. To do so, the Commission will first consider the impact of changes in the credit environment since the time of the 2009 GCOC proceeding. The Commission will then analyze the equity ratios that are required to attain the minimum credit metrics that were identified in Decision 2009-216. Finally, the Commission will turn to an assessment of each individual utility to determine whether specific adjustments to each company’s equity ratio are warranted.

173. The following table (grouped by sector) compares the equity ratios that were approved by the Commission in Decision 2009-216 with the equity ratios recommended by the applicants and interveners in this proceeding.

Table 7. Recommended vs. currently approved equity ratios

	Last approved[116] (%)	Recommended by the Utilities[117] (%)	Recommended by the UCA[118] (%)	Recommended by the CCA[119] (%)	Recommended by CAPP[120] (%)
Electric and Gas Transmission					
ATCO Electric TFO	36	38	34	36	
AltaLink	36	38	36	36	
ENMAX TFO	37	39	30	36	
EPCOR TFO	37	39	33	36	
ATCO Pipelines	45	47 (for 2011) 44 (for 2012)[121]	42 (for 2011) 30 (for 2012)	42 (for 2011) 40 (for 2012)	35 (for 2012)
Electric and Gas Distribution					
ATCO Electric DISCO	39	41	35	37	
ENMAX DISCO	41	43	35	39	
EPCOR DISCO	41	43	35	39	
ATCO Gas	39	41	34	37	
FortisAlberta	41	43	35	39	
AltaGas	43	45	40	41	

5.2 Credit environment

174. Much of the ROE and capital structure discussion in this proceeding centered on whether markets have returned to normal and whether the credit crisis discussed in Decision 2009-216 has passed. As discussed in more detail in Section 3.2 above, the Utilities cautioned that, while markets improved since the peak of the crisis, they have not returned to normal conditions. The interveners argued that economic parameters relevant to the cost of capital determinations have improved significantly and could be considered normal.

175. The Utilities submitted that, due to the persistence of significant downside risks to Canadian and global capital markets and economies, the two per cent across-the-board increase in common equity ratios approved in Decision 2009-216 was still relevant. Furthermore, Ms. McShane, who appeared on behalf of the Utilities, expressed her opinion that rating agencies do not view this across-the-board increase as temporary and, therefore, any reduction to equity ratios in the current proceeding could send negative signals to the market. As such, Ms. McShane used the capital structures approved in Decision 2009-216 as the point of departure in developing the Utilities' generic capital structure recommendations.[122]

176. In contrast, the UCA witnesses, Drs. Kryzanowski and Roberts, recommended that the Commission reverse the two percentage point equity ratio increase it awarded to all of the utilities in the 2009 GCOC. Their reasoning was that the additional two per cent was primarily awarded in order to account for the effects of the credit crisis, and because the credit crisis is

116 Decision 2009-216, Table 17, page 107.
117 Exhibit 209, Utilities argument, paragraph 129 (unless noted otherwise).
118 Exhibit 210.02, UCA argument, paragraph 215.
119 Exhibit 211, CCA argument, paragraph 58 (corrected as per Exhibit 213).
120 Exhibit 207.02, CAPP argument, paragraph 97.
121 Exhibit 208, ATCO Pipelines argument, paragraph 1.
122 Exhibit 209, Utilities argument, paragraphs 137-138.

over, there is no need to continue providing the Utilities with that additional financial flexibility.[123]

177. The UCA witnesses did not agree with Ms. McShane's position that the two per cent increase awarded in Decision 2009-216 was permanent and submitted that such an approach advocates the need for a permanent increase in shareholder returns, not because of what the actual capital market conditions were at the time of the decision, but because of the risk that problems similar to the financial crisis might arise in the future. Drs. Kryzanowski and Roberts submitted that the credit crisis was a rare event occurring approximately once in 75 years, and as such, it would not be fair to provide a permanent bonus to utility shareholders in order to insulate them against the potential effects of a near-catastrophic event that may not happen again for decades.[124]

178. The CCA supported the removal of the across-the-board two per cent increase in equity ratios awarded in the 2009 GCOC decision as proposed by the UCA, with the exception of the TFOs and ATCO Pipelines as further discussed below.[125] CAPP did not recommend any equity ratios other than for ATCO Pipelines, but did note that the financial market situation had stabilized and the need for any adjustment on this account was significantly reduced from the time of the 2009 GCOC decision when the Commission remained concerned about an uncertain future.[126]

Commission findings

179. As the Commission observed in Section 3.2 above, by the time of the 2011 GCOC hearing, economic parameters relevant to cost of capital determinations had improved significantly since the 2009 GCOC proceeding. Therefore, while cognizant of the lingering uncertainty in the debt markets related to concerns over sovereign debt in Europe and the U.S., the Commission agrees with Dr. Booth's opinion that the need for an adjustment to account for the financial crisis is reduced from the time of the 2009 GCOC decision.

180. However, as the Utilities pointed out, the credit crisis was only one of several factors that led to the two percentage point increase in equity thickness awarded in Decision 2009-216. Therefore, the Commission does not accept the UCA's proposal to reverse the two per cent equity ratio increase, solely because the credit crisis concerns have somewhat abated.

5.3 Credit metric considerations

5.3.1 Financial ratios, capital structure and actual credit ratings

181. Credit ratings measure the credit-worthiness of a firm. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments. This, in turn, allows the company to borrow at a lower interest rate. Utilities usually seek to maintain a credit rating in the A range.

182. As discussed in Section 5.1**Error! Reference source not found.** above, credit metrics (financial ratios) are an important part of bond rating agencies' considerations when assessing

123 Exhibit 210.02, UCA argument, paragraph 225.
124 Ibid., paragraphs 228-321.
125 Exhibit 211, CCA argument, paragraph 52.
126 Exhibit 207.02, CAPP argument, paragraph 90.

the risk of any particular company and assigning a credit rating. As noted in the 2009 GCOC decision, there are three principal credit metrics:

- EBIT coverage (interest coverage ratio), which is the company's earnings measured before deducting interest and taxes divided by total interest costs
- funds for operation (FFO)/debt, which is the company's funds from operations (net income plus depreciation and the increase in future income taxes) as a percentage of total debt
- FFO coverage, which is the company's funds from operations plus interest divided by total interest costs

183. The Commission observed in Decision 2009-216 that a number of Canadian utility companies finance their debt requirements directly in the debt market independently of any affiliated companies, thereby making it possible to directly see the equity ratios and credit metrics that are associated with stand-alone regulated utilities that have credit ratings in the A range. Consequently, the Commission examined the credit ratings of those companies for which credit rating reports were available on the record, in order to gain some insight into the credit metrics required to achieve an investment grade credit rating for a stand-alone utility.

184. In Decision 2009-216, the Commission observed the following minimum credit metrics associated with an A-range credit rating:[127]

- EBIT coverage of 2.0 times
- FFO coverage of 3.0 times
- FFO/debt ratio of 11.1 to 14.3%

185. The sample group of utilities that were examined in arriving at these observed credit metrics were exclusively Alberta utilities: AltaLink L.P., AltaLink Investments L.P., Fortis Inc., FortisAlberta and CU Inc., the parent of the ATCO group of utilities.

186. Additionally, after examining the actual credit ratings achieved by Canadian regulated utilities and the equity ratios associated with these credit ratings, the Commission observed that the actual equity ratios of the companies with a credit rating of A- or better ranged from 32.9 to 44.1 per cent, with a mid point of 38.5 per cent.[128]

187. The sample group of utilities that were examined in arriving at this observed range of equity ratios were the same Alberta utilities that were examined with respect to credit metrics (set out above) plus Newfoundland Power Inc.

188. In this proceeding, the Utilities noted that the importance of debt ratings in the A category for the Alberta utilities was reviewed in detail in the 2009 GCOC process, when the Commission established a capital structure that would allow a stand-alone utility to maintain a credit rating in the A range. In that regard, the Utilities submitted that there have been no fundamental changes in the capital markets or utility requirements for access to debt capital that would warrant revisiting that conclusion.[129]

[127] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
[128] Ibid., paragraph 359.
[129] Exhibit 209, Utilities argument, paragraphs 135.

189. The Utilities' position on the acceptability of the minimum credit metrics set out in Decision 2009-216 was not explicitly stated in argument, but appeared to be implicitly accepted. In particular, Ms. McShane testified that she used the minimum credit metrics observed in Decision 2009-216 as a point of departure.[130]

190. In her evidence, Ms. McShane also provided a review of changes in the equity ratios adopted for the Canadian peers of the Alberta utilities. Specifically, Ms. McShane indicated that, since the close of the oral portion of the last GCOC proceeding, there have been a number of increases in equity ratios approved by regulators. Based on her observation that the average regulated common equity ratio for utilities outside Alberta was 40 per cent, Ms. McShane considered this number to be a reasonable benchmark equity ratio for an average risk Alberta utility.[131]

191. The UCA submitted that it accepted the minimum credit metrics set out in Decision 2009-216 as reasonable guidelines, but emphasized Drs. Kryzanowski and Roberts' view that credit ratings do not follow a formula and depend on numerous qualitative factors and an examination by the rating agencies of numerous aspects of the businesses for which the ratings are prepared. The UCA witnesses also noted that their recommended equity ratios were generally consistent with the minimum equity ratios identified by the Commission.[132]

192. The CCA submitted that it did not accept benchmarking to the awards of other regulators as a tool for determining capital structure, as this method leads to a circularity problem. The CCA noted it accepts regulatory benchmarking only for information purposes, and only for comparison of methods, not for the actual awards.[133]

Commission findings

193. As discussed in Decision 2009-216, utilities usually seek to maintain their credit rating in the A range to avoid paying higher interest rates on debt typically associated with lower rating categories. Furthermore, as the Commission observed recently in Decision 2011-453[134] dealing with AltaLink's 2011-2012 GTA, a lower credit rating may limit a company's access to capital markets. In particular, the Commission noted that, as a BBB category issuer, a utility may face more significant challenges in accessing debt markets, particularly at a time of adverse market conditions.[135]

194. Therefore, the Commission reaffirms its finding that it is important to target the debt ratings for the Alberta utilities in the A category, as established in the 2009 GCOC process. The Commission agrees with the parties to this proceeding that minimum credit metrics associated with an A-range credit rating, which were observed in Decision 2009-216, can be accepted as reasonable guidelines for the purposes of this proceeding.

195. With respect to Ms. McShane's recommended benchmark equity ratio of 40 per cent, the Commission agrees with the CCA that equity ratios awarded by other regulators are of interest

130 Transcript, Volume 2, page 242, lines 8 to 11.
131 Exhibit 86.01, Kathleen McShane Opinion, pages 30-32.
132 Exhibit 210.02, UCA argument, paragraphs 156-160.
133 Exhibit 211, CCA argument, paragraphs 50 and 51.
134 Decision 2011-453: AltaLink Management Ltd. 2011-2013 General Tariff Application, Application No. 1606895, Proceeding ID No. 1021, November 18, 2011.
135 Decision 2011-453, paragraph 798.

but are far from determinative of the capital structure this Commission should award. Furthermore, in Decision 2009-216, the Commission observed the actual equity ratios of the utilities in the A range rating category. Ms. McShane did not specify whether her analysis of capital ratios awarded by other regulators was limited only to the A-rated utilities.

5.3.2 Equity ratios associated with minimum credit metrics

196. In Decision 2009-216, the Commission provided a sensitivity analysis of the three key credit metrics to changes in the equity ratio. Assuming an embedded cost of debt of 6.5 per cent, an ROE of 8.75 per cent (the 2009 placeholder level), an income tax rate of 29 per cent, and assuming the annual depreciation expense as a percentage of invested capital equal to the utility average of six per cent, the Commission calculated the following minimum equity ratios required to achieve the observed minimum credit metrics:[136]

- The minimum equity ratio to achieve a 2.0 EBIT coverage ratio was 34 per cent.
- Minimum equity ratios in the range of 30 to 36 per cent would achieve FFO/debt percentages of 11.1-14.3.
- A minimum equity ratio of 33 per cent was required to achieve an FFO coverage ratio of at least 3.0.

197. Ms. McShane proposed to update the Commission's analysis in Decision 2009-216 by making three adjustments. The first was to assume a reduction in average debt costs for the average utility. The second was to include an assumed five per cent construction work in progress (CWIP) in the credit metric calculation for the hypothetical average utility. The third involved recalculating the hypothetical credit metrics using the lower tax rates that apply in 2012.

198. With respect to the first adjustment, Ms. McShane noted that a review of the 2009 embedded debt costs provided by the Alberta utilities in their Rule 005[137] filing requirements indicated that there has been a marginal decline since 2007 (less than 10 basis points). Therefore, Ms. McShane proposed to use a 6.4 per cent average embedded cost of debt as compared to the 6.5 per cent rate used by the Commission in Decision 2009-216, which would have the effect of improving credit metrics and decreasing the necessary equity ratio.[138]

199. Next, Ms. McShane indicated that even a relatively small percentage of CWIP has a measurable impact on EBIT interest coverage ratios. Based on her observation that the median of CWIP as a per cent of total regulated assets in 2009 for the Alberta utilities was around five per cent, Ms. McShane proposed to include this amount of CWIP in the calculations of equity ratios required to achieve the minimum EBIT coverage ratios observed by the Commission.

200. With respect to the impact of income taxes, Ms. McShane indicated that, in 2012, the combined provincial and federal corporate income tax rate will be 25 per cent, compared to the 29 per cent used in the analysis set out in Decision 2009-216. Furthermore, the Utilities' witness indicated that the median actual effective income tax rate for the taxable Alberta Utilities in 2009 (excluding AltaLink) was less than half the statutory combined rate.[139] As such, Ms. McShane

136 Decision 2009-216, paragraphs 352, 354 and 356.
137 AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
138 Exhibit 86.01, Kathleen McShane Opinion, page 25, lines 638-646.
139 Ibid., page 27, lines 674-683.

proposed to use the 12.5 per cent tax rate in equity ratio calculations, which represents 50 per cent of the 2012 statutory tax combined rate of 25 per cent.

201. Incorporating these recommended assumptions regarding the embedded cost of debt, effective tax rate and presence of CWIP,[140] the Utilities provided updated versions of the Commission's analysis of equity ratios in Decision 2009-216 as follows:

Table 8. Credit metrics compared to equity ratios – McShane's evidence

	EBIT coverage		FFO/Debt		FFO coverage	
Equity Ratio	Table 13 in Decision 2009-216	Updated and expanded assumptions	Table 14 in Decision 2009-216	Updated and expanded assumptions	Table 15 in Decision 2009-216	Updated and expanded assumptions
30%	1.8	1.6	12.32	11.71	2.90	2.78
31%	1.9	1.6	12.63	12.00	2.94	2.82
32%	1.9	1.6	12.94	12.29	2.99	2.87
33%	1.9	1.7	13.26	12.60	**3.04**	2.92
34%	2.0	1.7	13.60	12.92	3.09	2.97
35%	**2.0**	1.7	13.94	13.25	3.14	**3.02**
36%	2.1	1.8	**14.30**	13.58	3.20	3.07
37%	2.1	1.8	14.66	13.93	3.26	3.13
38%	2.2	1.9	15.04	**14.29**	3.31	3.18
39%	2.2	1.9	15.43	14.66	3.37	3.24
40%	2.3	1.9	15.83	15.04	3.44	3.30
41%	2.3	**2.0**	16.25	15.44	3.50	3.36
42%	2.4	2.0	16.68	15.85	3.57	3.43
43%	2.4	2.1	17.13	16.27	3.63	3.49
44%	2.5	2.1	17.59	16.71	3.71	3.56
45%	2.6	2.2	18.07	17.16	3.78	3.63
46%	2.6	2.2				
47%	2.7	2.3				

Source: Exhibit 209, Utilities argument, Attachment 2.

202. Based on her evaluation of the net effect of the three adjustments on credit metrics (as presented in Table 8 above), Ms. McShane concluded that an increase in the common equity ratios of no less than two percentage points was warranted. The highlighted examples in the table illustrate that a minimum two percentage point equity ratio increase is necessary to restore the credit metrics to the levels that applied under the 2009 calculations, given Ms. McShane's assumptions.

203. The UCA took issue with the Utilities' inclusion of CWIP and a lower tax rate in the credit metrics calculation. The UCA submitted that, in Decision 2009-216, the Commission implicitly took these factors into account and the resulting equity ratios were well received by the rating agencies. In the UCA's opinion, the relevant facts or circumstances have not changed

140 Utilities' assumptions: embedded cost of debt of 6.4 per cent, ROE of 8.75 per cent, effective tax rate of 12.5 per cent (50 per cent of 2012 statutory tax rate), 5.0 per cent CWIP as percentage of regulated assets, depreciation rate of 6.0 per cent.

since 2009, and as such, Ms. McShane's analysis was simply an arbitrary re-definition of the Commission's model.[141]

204. The UCA also noted that, in the case of the two transmission utilities that have the highest levels of CWIP – ATCO Electric and AltaLink, the Commission addressed this issue in other ways in their respective GTAs.[142]

205. With respect to Ms. McShane's adjustment related to lower tax rates, the UCA observed that any changes in tax rates affects only the EBIT coverage credit metric, since the FFO/debt and FFO interest coverage metrics are after tax measures. The UCA also submitted that, under a flow-through tax regime, changes in either statutory or effective tax rates do not have any material impact on bondholders or the creditworthiness of the utilities, because the funds collected for taxes on a forecast basis are earmarked for payment to the tax authorities and so are not available to pay creditors.[143]

206. The UCA conceded that lower tax rates reduce the EBIT interest coverage ratio but argued that credit rating agencies do not take the "rigidly rule-based formulaic approach" to understanding credit ratings and credit metrics, and arrive at a balanced assessment of creditworthiness that takes into account all of the moving parts that affect the interests of bond investors.[144] As a result of these considerations, the UCA argued there was no need to update the Commission's credit metric analysis tables in Decision 2009-216.

207. The CCA agreed with the UCA's analysis on CWIP and effective income taxes. Specifically, the CCA argued that there should be no adjustment for income tax rates because deferred income tax must ultimately be paid and financial analysts have not identified deferred income taxes as a risk. In addition, the CCA observed that the effective income tax rate varies greatly from utility to utility and, therefore, any required adjustments should be made on a utility-specific, rather than generic, basis.[145]

208. Similarly, the CCA objected to the across-the-board adjustment for CWIP. The CCA expressed its opinion that a large amount of CWIP is currently a problem for the TFOs but not for all the utilities. The CCA submitted that there is little risk from CWIP and that no adjustment to ROE was necessary for any amount of CWIP.[146]

209. In reply argument, the Utilities submitted that the absence of downgrades does not constitute an appropriate basis for evaluating the reasonableness of Ms. McShane's recommendations and argued that it was necessary to include CWIP amounts in the equity ratio analysis so that the credit metrics identified by the Commission as minimums would be achievable.

210. The Utilities also took issue with the UCA's argument that the income tax allowance is earmarked for payment to the income tax authorities and is not available for payment to creditors. The Utilities submitted that this view does not comport to the manner in which the debt rating agencies evaluate a company's ability to meet its debt obligations. The Utilities explained

141 Exhibit 210.02, UCA Argument, paragraphs 167 and 173.
142 Ibid., paragraph 170.
143 Ibid., paragraphs 178-179.
144 Ibid., paragraphs 182-184.
145 Exhibit 211, CCA argument, paragraphs 37-38.
146 Ibid., paragraph 40.

that, since interest expense is tax-deductible, income taxes payable are partly a function of how much interest is paid and therefore, it is logical that the debt rating agencies would consider the pre-tax funds that a company has available to cover its debt obligations.[147]

Commission findings

211. In Decision 2009-216, the Commission presented its analysis of equity ratios required to achieve the minimum credit metrics considered to be associated with credit ratings in the A range. The Commission expressly stated that this analysis did not include the consideration of CWIP or cash flows created by positive or negative differences between tax collected and tax paid.[148]

212. In this proceeding, the Utilities pointed out that even a small percentage of CWIP has a measurable impact on credit metrics. As noted in Decision 2009-216, the Commission agrees that the presence of CWIP lowers the credit metrics.[149] In fact, recognizing this reality, the Commission, through its issues list, invited parties to update the credit metric tables with relevant assumptions as to the typical level of CWIP for the Alberta utilities.

213. As discussed further in this section, the Commission agrees with the UCA and the CCA that the adjustment for CWIP is not necessary for ATCO Electric TFO and AltaLink, given that this matter was recently addressed in their respective GTAs. However, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for other Alberta utilities.

214. Specifically, the UCA argued that updating the Commission's tables with typical amounts of CWIP and lower income taxes advocates a formulaic approach to credit metrics. The Commission accepts the UCA's point that rating agencies supplement their analysis of credit metrics with a number of other considerations to arrive at a balanced assessment of a company's creditworthiness. As discussed in Section 5.6 below, the Commission's determination on the matter of capital structure is not limited to credit metric analysis and includes a number of factors such as the current credit environment and the ranking of the utility segments based on business risk.

215. The UCA also argued that no adjustment for a typical level of CWIP and lower income taxes is necessary, since the credit rating agencies appeared to be satisfied with the equity ratios approved in Decision 2009-216, as evidenced by the fact that no utilities have been downgraded since 2009. However, the Commission observes that, due to a number of factors, including the impact of the financial crisis and large capital additions (where applicable), the equity ratios approved in 2009 exceeded the minimum levels indicated by the credit metric analysis in that decision by at least two percentage points.[150] Accordingly, the Commission considers that the favourable reaction of the rating agencies may be attributed to the fact that the last approved equity ratios were sufficient to account for typical amounts of CWIP, not the fact that no adjustment for CWIP was necessary.

[147] Exhibit 220.02, Utilities reply argument, paragraph 94.
[148] Decision 2009-216, footnote 326 on page 94.
[149] Ibid., footnotes 323 and 325.
[150] In paragraph 357 of Decision 2009-216, the Commission observed that for an average Alberta utility, the equity ratio associated with the minimum credit metrics would be approximately 34 per cent (34 per cent based on the EBIT analysis, 33 per cent based on the FFO coverage analysis and 30 to 36 per cent based on the FFO/Debt analysis). Table 17 of Decision 2009-216 shows that the minimum equity ratio awarded was 36 per cent.

216. Regarding the CCA's argument that there is little risk from CWIP and that no adjustment to ROE is necessary for any amount of CWIP, the Commission reiterates that the adjustment to the credit metric calculations in regard to CWIP that was solicited through the issues list was not related to the risk of recovering CWIP balances. Rather, the issue was that CWIP mathematically lowers the credit metrics. The CCA did not address this point.

217. Consequently, the Commission is not persuaded by the interveners' arguments that CWIP should not be considered in the credit metric calculations for the Alberta utilities. The Commission has considered the evidence of Ms. McShane that the median of CWIP as a percentage of total regulated assets in 2009 for the Alberta utilities was over five per cent, and finds this number to be a reasonable estimate. The Commission has reflected this level of CWIP in its updated analysis on credit metrics and associated equity ratios, presented in Table 9 below.

218. The Commission also acknowledges the Utilities' evidence that, in 2012, the combined provincial and federal statutory income tax rate will be 25 per cent, as compared to the 29 per cent used in Decision 2009-216. The Commission agrees with Ms. McShane that the income tax rate should be updated in the analysis.

219. In disputing the relevance of lower income tax rates, the UCA submitted that income taxes collected are ear-marked for payment to the tax authorities and so are not available to pay creditors. However, in the event that unforeseen expenses cause profits to decline from the forecast level, the income tax payable would decline and the cash that would otherwise go to taxes would become available to pay interest expenses. Therefore, income taxes collected are in fact partly available to pay creditors in situations where the profit, and therefore the actual amount of income tax payable, is lower than forecast. Additionally, the income tax collected would be fully available to pay interest in the circumstance where profit was zero or negative. Presumably, this is why EBIT (earnings before interest and tax) is important to credit rating agencies and debt investors, rather than simply earnings before interest.

220. However, the Commission does not accept the Utilities' recommendation of using the effective tax rate in the credit metrics analysis. The Commission agrees with the CCA's argument that, because the effective income tax rate varies greatly from utility to utility, any required adjustments should be made on a utility-specific, rather than generic basis. The Commission considers that those utilities that encounter credit rating issues because they are on the flow-through tax method can apply to adopt the future income tax method and thereby collect the full statutory income tax rate. For these reasons, the Commission will use an updated statutory income tax rate of 25 per cent in its analysis below.

221. Using an ROE of 8.75 per cent approved in this decision for 2011 and 2012, and assuming an embedded interest cost of 6.4 per cent, a depreciation rate (as a percentage of invested capital) of six per cent, a tax rate of 25 per cent, and CWIP (as a percentage of rate base) of five per cent, the Commission calculated the key credit metrics and the corresponding equity ratios as follows:

Table 9. Credit metrics compared to equity ratios – Commission analysis

	EBIT coverage[151]		FFO/Debt (%)		FFO coverage	
Equity ratio	**Table 13 in Decision 2009-216**	**Updated and expanded assumptions**	**Table 14 in Decision 2009-216**	**Updated and expanded assumptions**	**Table 15 in Decision 2009-216**	**Updated and expanded assumptions**
30%	1.8	1.7	12.32	11.73	2.90	2.79
31%	1.9	1.7	12.63	12.03	2.94	2.83
32%	1.9	1.8	12.94	12.32	2.99	2.88
33%	1.9	1.8	13.26	12.63	**3.04**	2.93
34%	**2.0**	1.8	13.60	12.95	3.09	2.98
35%	2.0	1.9	13.94	13.28	3.14	**3.03**
36%	2.1	1.9	**14.30**	13.62	3.20	3.08
37%	2.1	**2.0**	14.66	13.96	3.26	3.13
38%	2.2	2.0	15.04	**14.32**	3.31	3.19
39%	2.2	2.1	15.43	14.7	3.37	3.25
40%	2.3	2.1	15.83	15.08	3.44	3.31
41%	2.3	2.2	16.25	15.48	3.50	3.37
42%	2.4	2.2	16.68	15.89	3.57	3.43
43%	2.4	2.3	17.13	16.31	3.63	3.5
44%	2.5	2.3	17.59	16.75	3.71	3.57
45%	2.6	2.4	18.07	17.21	3.78	3.64

222. Table 9 shows that, given the Commission’s assumptions, the minimum equity ratio for Alberta utilities should be 37 per cent based on the EBIT analysis, 30 to 38 per cent based on the FFO/debt analysis and 35 per cent based on the FFO interest coverage analysis. These values show that, as a result of incorporating a typical amount of CWIP and accounting for the lower level of income taxes, the minimum equity levels produced by the credit metric analysis in this decision are somewhat higher than the equity ratios estimated in Tables 13 to 15 of Decision 2009-216.

223. However, as the Commission pointed out earlier in this section, due to a number of factors, including the impacts of the financial crisis and the impact of large capital additions, among others, the equity ratios approved in Decision 2009-216 somewhat exceeded the levels indicated by the credit metric analysis in that decision. In particular, Table 9 above demonstrates that by and large, the currently approved equity ratios of the Alberta utilities meet or exceed the minimum levels determined by the credit metric analysis. In light of these factors, the Commission considers that no across-the-board increase to the currently approved equity ratios for the Alberta utilities is warranted.

[151] As discussed in Exhibit 209, Attachment 2 to the Utilities argument, Ms. McShane calculated the EBIT coverage ratios using the S&P methodology, which includes the equity portion of an allowance for funds used during construction (AFUDC) in EBIT component. The Commission used the DBRS methodology, which excludes the equity portion of AFUDC from earnings, resulting in more conservative estimates. However, under the five per cent CWIP assumption, the difference between the two methods is minimal.

5.4 Ranking risk by regulated sector

224. In previous GCOC decisions, the Commission ranked the riskiness of the various utility sectors in Alberta based on an analysis of business risk. Business risk affects the perceived uncertainty in future operating earnings and hence determines the capacity for a business to be financed with debt as opposed to equity.

225. In Decision 2009-216, the Commission observed that the electric transmission sector had the least risk. The Commission also found that, in general, the electricity distribution segment was slightly more risky than the electric transmission sector. The Commission agreed that ATCO Gas had a similar level of business risk compared to electric distribution companies, and that AltaGas was more risky than ATCO Gas due to its small size. ATCO Pipelines (transmission) was found to be more risky than ATCO Gas (distribution).[152]

226. In the current proceeding, none of the expert witnesses put forward evidence which would indicate materially changed business risks for the utility sectors since Decision 2009-216, with the exception of ATCO Pipelines in light of the integration with Nova Gas Transmission Ltd. (NGTL).

227. In particular, the Utilities recommended no adjustment, generic or company specific, to capital structures due to the recognition of high levels of contributions in aid of construction (CIAC).[153] The Utilities recommended that compensation for high levels of CIAC occur by way of a management fee, as discussed in Section 6 below. The same argument was put forward by the UCA.[154]

228. As well, the Utilities pointed out that their assessment of the business risks upon which their deemed capital structure recommendations was based did not reflect consideration of the potential of changed risks associated with the implementation of a PBR regime in the near future. The Utilities reasoned that, until the specifics of the form of PBR to which any given utility becomes subject are known, a grounded assessment of changes in risk cannot be made.[155]

229. Furthermore, parties to this proceeding submitted that they were not aware of any adjustments to capital structure that would be required to accommodate growth above the historic trend. The UCA submitted that, to the extent that credit related issues have arisen in the context of mandated transmission builds by Alberta TFOs, those have been, or will be, addressed through utility specific measures like including CWIP in rate base or allowing the collection of future income taxes.[156] The Utilities supported this view.[157]

Commission findings

230. The Commission has evaluated the expert evidence of witnesses representing interested parties to this proceeding, and agrees that business risks for Alberta utilities have not changed materially since 2009, with the exception of ATCO Pipelines.

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[152] Decision 2009-216, paragraphs 370-371.
[153] Exhibit 209, Utilities argument, paragraph 154.
[154] Exhibit 210.02, UCA argument, paragraph 201.
[155] Exhibit 209, Utilities argument, paragraph 155.
[156] Exhibit 210.02, UCA argument, paragraph 213.
[157] Exhibit 209, Utilities argument, paragraph 156.

231. Consequently, the Commission reaffirms its findings in the 2009 GCOC decision. In particular, as outlined in Decision 2009-216,[158] the Commission finds that the electric transmission sector has the least risk. The electricity distribution segment is slightly more risky than the electric transmission sector. ATCO Gas has a similar level of business risk as compared to electric distribution companies. Due to its small size, AltaGas is more risky than ATCO Gas.

232. The Commission findings with respect to the impact of CIAC are presented in Section 6 of this decision.

5.5 Further company-specific considerations

233. The Commission now turns to a consideration of further adjustments to the equity ratios of individual companies based on their specific business risks.

5.5.1 Adjustment for non-taxable status

234. In Decision 2009-216, the Commission affirmed the two percentage point adjustment to common equity ratios for non-taxable utilities, initially approved in Decision 2004-052, on the basis of higher earnings volatility and a negative impact on credit metrics. This adjustment applied to ENMAX and EPCOR utilities and was extended to FortisAlberta, since at the time of the 2009 GCOC decision FAI anticipated being a non-taxable entity until at least 2013.[159]

235. In this proceeding, Ms. McShane noted that, to fully reflect the impact of non-taxability on pre-tax interest coverage ratios, the common equity adjustment would need to be six per cent. Notwithstanding this, the Utilities submitted they supported the findings of the Commission and its predecessor that two percentage points increase is warranted and recommended that this adjustment for non-taxable status continue to apply.[160]

236. Ms. McShane also indicated that, based on FortisAlberta's assessment, it will collect zero income taxes in rates through at least 2016 and, therefore, FortisAlberta remained a de facto non-taxable entity for purposes of this proceeding.[161] As such, in this proceeding, each of the non-taxable utilities (ENMAX and EPCOR as legally non-taxable and FortisAlberta as de facto non-taxable) were seeking a deemed capital structure that continued the treatment established in Decision 2009-216 and Decision 2004-052.

237. The UCA submitted that the additional two per cent equity thickness that has been provided to non-taxable utilities due to their higher earnings volatility was not reasonable or necessary. Specifically, the UCA indicated that the argument regarding increased earnings volatility assumes that any variance in earnings is symmetrical when in fact over-earning is more common. Relying on the data on historical earned ROEs relative to allowed ROEs provided by the Commission in Exhibit 161, the UCA submitted that Alberta utilities are more likely to over-earn their allowed returns than to under-earn, and the benefit of the same amount of over-earning increases with a lower tax rate.[162]

158 Decision 2009-216, paragraphs 370-371.
159 Decision 2009-216, paragraphs 383-384.
160 Exhibit 209, Utilities argument, paragraph 141.
161 Exhibit 86.01, Kathleen McShane Opinion, page 32, lines 812-817.
162 Exhibit 210.02, UCA Argument, paragraphs 190-193.

238. During the hearing, Dr. Roberts provided the following explanation on this point:

> 21 Another point I might add is that if a company
> 22 is not taxable, and it earns, let's say, an extra million
> 23 dollars, it gets to keep 1 million, whereas if it's taxable,
> 24 it gets to keep less because part of it has to go to the
> 25 Canada Revenue Agency.[163]

239. As such, the UCA argued that, in practice, non-taxable status benefits utility shareholders on average by increasing their expected effective ROE relative to the effective ROEs for taxable utilities. In light of this practical benefit, the UCA submitted that there is no need to continue providing shareholders of non-taxable utilities with an even further benefit in the form of a higher allowed equity ratio. The UCA argued that the shareholders of non-taxable utilities are already better off, in terms of their expected return, than shareholders of taxable utilities, and that effect must at least offset whatever minor volatility disadvantage is associated with non-taxable status.[164]

240. In addition, the UCA submitted that, even if the Commission were to maintain the additional two per cent equity for ENMAX and EPCOR, this adjustment should not apply to FortisAlberta which, although temporarily not paying or collecting tax, remains a taxable utility. The UCA submitted that this situation would eventually reverse and FortisAlberta was just as taxable as every other utility.[165]

241. In reply, the Utilities submitted that the document identified as Exhibit 161 contained not just data publicly filed by the Utilities as part of the AUC Rule 005 reports, but adjustments which purport to alter that data. Therefore, the Utilities argued that this document could not form an evidentiary basis for any conclusions proffered by the UCA in its argument, or reached by the Commission in its decision.[166]

Commission findings

242. The Commission acknowledges that historical ROE data provided in Exhibit 161, along with the publicly available Rule 005 numbers, contain Commission staff calculations. Indeed, recognizing this fact, the Commission invited the Utilities to comment on the numbers provided in Exhibit 161, either through supplemental filings or in argument.[167] The Utilities did not provide any comments on the data in Exhibit 161. Nevertheless, the issue of whether this document can be used as evidence in this proceeding is not germane to the Commission's determination on this matter.

243. In the Commission's view, the UCA's argument that the additional two per cent equity thickness for non-taxable utilities was not necessary fails to account for the fact that the active constraint on the minimum equity ratios is the risk tolerance of debt investors, and not equity investors. Debt investors are concerned by, and could be affected by, the downside risk of an earnings shortfall. In addition, it is equity investors and not debt investors that benefit from upside risk. This is because unlike equity investors, debt holders can not gain more than the

[163] Transcript, Volume 6, page 771, lines 21 to 25.
[164] Exhibit 210.02, UCA Argument, paragraph 195.
[165] Ibid., paragraphs 196-199.
[166] Exhibit 220.02, Utilities reply argument, paragraphs 101-104.
[167] Transcript, Volume 1, page 15, line 7 to page 16, line 6.

promised interest rate, even if the company performs unusually well. For these reasons, debt investors focus on downside risk, not upside.

244. As such, the Commission reaffirms its findings in Decision 2009-216 that, while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases interest coverage ratios, and thereby adds to risk from the debt holder's perspective. Accordingly, the Commission will maintain the addition of the two percentage point increase to the equity ratios of income tax exempt utilities.

245. With respect to FortisAlberta, the Commission notes that it became a de facto non-taxable entity in 2006, and is expected to persist in this status at least through 2016.[168] As such, the Commission considers that this situation cannot be characterized as short run non-taxability. The Commission agrees with the UCA that eventually FortisAlberta will have the same income tax liability as any other taxable entity. However, given the expected duration of FortisAlberta's de facto non-taxable status, the Commission does not share the UCA's view that higher earnings volatility associated with non-taxability will be offset by reduced earnings volatility during the future periods over which this findings this decision will apply.

246. Therefore, in the Commission's view, it is warranted to treat FortisAlberta as a non-taxable entity for the purposes of this proceeding, since it has not collected any income taxes since 2006 and is not expected to until at least 2016. This status would change if FortisAlberta became an income tax paying entity or if the Commission were to change from the flow through method of accounting for income taxes for regulatory purposes to normalized taxes or another similar method in the future.

5.5.2 Transmission facility owners and the risk of stranded assets

247. During the hearing, the AESO suggested that ratepayers rather than utility shareholders are at risk for stranded TFO assets.[169] The Commission invited the parties to comment on whether this reality needs to be considered in the risk assessment for the TFOs.

248. The UCA submitted that the AESO's position was likely consistent with the practice in most regulatory jurisdictions and with the expectations of the Utilities. The UCA expressed its opinion that any consideration of where the burden of stranded assets should fall is likely to be fact-specific, and therefore, it would not be appropriate to consider this matter generically in the current proceeding, especially considering that it was not in the original scope.[170]

249. The Utilities expressed similar concerns with the inclusion of this matter as part of this proceeding and pointed out that to date, there have been no examples of stranded assets for either transmission or distribution utilities. The Utilities implied that the AESO's position was consistent with regulatory compact, under which tariffs should provide the opportunity to recover the costs of prudent investments in the system. As such, the Utilities submitted that the business risks of the utilities have not materially changed.[171]

250. The CCA argued for symmetry and reciprocity in the treatment of utility gains and losses. Citing portions of the Stores Block decision, the CCA stated that if gains from the sale of assets

[168] Exhibit 86.01, Kathleen McShane opinion, page 32, lines 812-817.
[169] Transcript, Volume 3, page 493, line 22 to page 494, line 13.
[170] Exhibit 210.02, UCA argument, paragraph 214.
[171] Exhibit 209, Utilities argument, paragraphs 158 and 159.

which are not used and useful are to the account of the utility shareholder, losses should also be to the account of the utility shareholder. Therefore, in the hypothetical example on the record, the CCA submitted it did not agree with the position of the AESO.[172]

Commission findings

251. As set out in Section 7 below dealing with the proposed Rider I concept, the Commission does not share the AESO's view that ratepayers, rather than utility shareholders, are at risk for stranded TFO assets. Specifically, as outlined further in this decision, the Commission considers that any stranded assets should not remain in rate base.

252. The Commission acknowledges that this finding may have certain implications for the quantum of business risks of the transmission utilities. However, as both the Utilities and the AESO[173] pointed out, to date, there have been no examples of stranded assets in Alberta. Furthermore, the Commission considers that any assessment of risk associated with the potential for stranded assets, for the purposes of adjusting capital structure, would be best dealt with on a case-specific determination when the situation arises. Therefore, the Commission will not consider this factor in its risk assessment for TFOs for the purposes of this proceeding.

5.5.3 ATCO Pipelines' system integration with NGTL

253. In September 2008, ATCO Pipelines and Nova Gas Transmission Ltd. (NGTL) reached an agreement under which the two companies would combine physical assets and offer a single suite of services to provide gas transmission service. This integration was expected to be completed on October 1, 2011. Consequently, parties to this proceeding proposed a change in ATCO Pipelines' post-integration capital structure to reflect the altered risk profile of the company.

254. In her evidence, Ms. McShane indicated that because there have been no fundamental changes in the capital markets or ATCO Pipelines' requirements for access to debt capital, there was no reason to revisit the capital structure established in Decision 2009-216.[174] Furthermore, ATCO Pipelines pointed to Decision 2010-228,[175] which provided that its common equity ratio for 2011 would not take into account post integration factors.[176] As such, ATCO Pipelines requested approval of a common equity ratio of 47 per cent for 2011, which was reflective of the 2010 approved ratio of 45 per cent and the across-the-board two percentage points increase proposed by the Utilities.

255. ATCO Pipelines further submitted that although its post-integration business risk will decrease, it will still be higher than business risk of the Alberta electric distribution utilities. This conclusion was based on the assessment of the following risk factors:[177]

- competition for both gas supply and markets, which has decreased with NGTL, but has increased with Alliance Pipelines

172 Exhibit 211, CCA argument, paragraph 42.
173 Transcript, Volume 3, page 493 lines 3 to 5.
174 Exhibit 80.01, Kathleen McShane opinion on capital structure for ATCO Pipelines, page 7, A8.
175 Decision 2010-228: ATCO Pipelines. 2010-2012 Revenue Requirement Settlement and Alberta System Integration, Application No. 1605226, Proceeding ID No. 223, May 27, 2010.
176 Decision 2010-228, paragraph 88.
177 Exhibit 208, ATCO Pipelines argument, paragraph 5.

- supply risk arising from continued decline of the Western Canada Sedimentary basin (WCSB) reserves and especially those within ATCO Pipelines' operating footprint
- construction and financing risk, due to the doubling of ATCO Pipelines' annual capital expenditures

256. As a result, ATCO Pipelines requested a 44 per cent common equity ratio for 2012, which was the mid-point between the 41 per cent common equity ratio recommended by Ms. McShane for gas and electric distribution utilities and the 47 per cent recommended common equity ratio for 2011 for ATCO Pipelines.[178] ATCO Pipelines also argued that the recommended equity ratio of 44 per cent takes into account maintenance of its creditworthiness and financial integrity, assurance that it contributes its fair share to the maintenance of the credit ratings of its parent, and the opportunity to earn an overall return commensurate with investments of comparable risk.[179]

257. Dr. Booth, testifying on behalf of CAPP, pointed out that with integration, ATCO Pipeline's revenue requirement will be paid by NGTL like any other cost of NGTL doing business and ahead of NGTL paying anything to its shareholders. Dr. Booth indicated that this arrangement was very similar to the way in which Alberta electric transmission utilities recover their system costs from the distributors via the Alberta Electric Systems Operator (AESO), and the only real question was the risk of NGTL not being able to make those payments.[180]

258. In that regard, CAPP's witness noted that the combined ATCO Pipelines and NGTL systems sit on top of vast natural gas resources that will provide gas for many decades to come. Based on his analysis of available reports and forecasts, Dr. Booth noted that unconventional supplies will dramatically impact total production from the WCSB, where the growth in Horn River and Montney supply will offset the decline in conventional production.[181] As a result, CAPP argued that with these new supplies, ATCO Pipelines' supply risk has significantly reduced.

259. CAPP also submitted that ATCO Pipelines' competition risk was significantly reduced post integration, since the impact of any successful competition by Alliance Pipelines was no longer borne by ATCO Pipelines by itself, but rather by the combined ATCO Pipelines/NGTL system. Based on the above considerations, CAPP concluded that ATCO Pipelines' risk of not receiving its revenue requirement was no higher than that of Alberta TFOs and recommended that the Commission use a similar common equity ratio of 35 per cent for ATCO Pipelines in 2012.[182]

260. Mr. Marcus, testifying for the UCA, submitted that competitive and market risks will no longer be present for ATCO Pipelines post-integration. Therefore, Mr. Marcus stated that ATCO Pipelines will be similar in risk to an electric transmission utility, which receives fixed payments for services from the AESO.[183] Given this analysis, Drs. Kryzanowski and Roberts recommended a common equity ratio of 42 per cent for 2011, unchanged from their recommendation made in

[178] Exhibit 80.01, Kathleen McShane opinion on capital structure for ATCO Pipelines, page 18, A21.
[179] Exhibit 208, ATCO Pipelines argument, paragraph 6.
[180] Exhibit 78.02, evidence of Laurence D. Booth, paragraph 205.
[181] Ibid., paragraph 208; Exhibit 207.02, paragraphs 94-95.
[182] Exhibit 207.02, CAPP argument, paragraph 97.
[183] Exhibit 81.04, prepared testimony of Mr. William B. Marcus, page 13, lines 3-10.

2009. For 2012, they recommended a common equity ratio of 30 per cent, due to the elimination of competition with NGTL.[184]

261. The CCA also expressed its opinion that ATCO Pipelines faces significant reductions to its business risks after integration and indicated that the company will be in danger of not recovering its revenue requirement only in the case of a default by NGTL. With respect to the competition from Alliance Pipelines, the CCA submitted that this risk may not materialize within the test years of this proceeding.[185]

262. As a result, the CCA argued that ATCO Pipelines' risks are no different from the risks faced by NGTL and recommended the equity thickness of 40 per cent in 2012, as awarded to NGTL by the National Energy Board. For 2011, the CCA recommended an equity ratio of 42 per cent, which is a weighted capital structure of 75 per cent pre-integration and 25 per cent post-integration, based on October 1, 2011 as the integration effective date.

Commission findings

263. In Decision 2010-228, dealing with ATCO Pipelines' 2010-2012 revenue requirement settlement and system integration, the Commission accepted the approach proposed by the parties to that proceeding and agreed that ATCO Pipelines' equity ratio for 2010 and 2011 will exclude the impact of integration, while 2012 shall take integration into account.[186] Therefore, the Commission will base its determinations on ATCO Pipelines' 2011 common equity ratio taking into account any across-the-board adjustments applicable to all utilities, but without considering the impact of integration.

264. Furthermore, in Decision 2010-228 the Commission explained that post integration, ATCO Pipelines will collect its Commission approved revenue requirement through a monthly charge to NGTL, the ATCO Pipelines (AP) Charge. NGTL's revenue requirement, including the AP Charge, will be collected from customers using the combined regulated ATCO Pipelines and NGTL gas transmission systems, the Alberta System. Customers would pay one toll for use of the Alberta System and be subject to a single tariff with a single set of terms and conditions of service.[187]

265. All parties to this proceeding acknowledged that with this arrangement, the only risk of ATCO Pipelines not recovering its revenue requirement is if NGTL was unable to make its payments. As such, the Commission considers that in 2012, the business risks faced by ATCO Pipelines have been significantly reduced through its integration with NGTL.

266. The UCA and CAPP witnesses argued that the business risk of ATCO Pipelines post integration is comparable to the risk of Alberta TFOs, which recover their revenue from the AESO. However, the Commission considers that this comparison is not entirely accurate. Unlike the AESO, the combined ATCO Pipelines/NGTL system faces certain competition and supply risks (as presented in the Utilities' argument), which should be taken into account.

267. In light of the above considerations, the Commission finds that ATCO Pipelines' post integration business risk is higher than the level of risk faced by the electric transmission sector,

184 Exhibit 210.02, UCA argument, paragraphs 202-204.
185 Exhibit 211, CCA argument, paragraph 55.
186 Decision 2010-228, paragraph 91.
187 Ibid., paragraph 115.

but is somewhat lower than the risk of electric and gas distribution sectors. The Commission's determination on ATCO Pipelines' capital structure for 2012 presented in Section 5.6 below reflects these findings by setting the equity ratio at the average of those two sectors.

268. The Commission does not consider that this determination will have a significant impact on ATCO Pipelines' credit metrics. In the Commission's view, setting the equity ratio for ATCO Pipelines at the midpoint of that of the TFOs and the distribution utilities will be sufficient to attain the minimum credit metrics associated with credit ratings in the A range. This follows logically because the Commission will award equity ratios to those two sectors designed to achieve A ratings and the Commission has found that ATCO Pipelines' risk is midway between the risk of those two sectors. Furthermore, the Commission considers that if, after assessing the impacts of this decision, ATCO Pipelines remains concerned about its credit metrics, this matter can be addressed at the time of its next GTA.

5.5.4 Additional concerns raised by the UCA

269. As discussed in sections above, the UCA based its recommendations on the capital structures for the Alberta utilities based on Drs. Kryzanowski and Roberts opinion that:

- a two percentage point reduction was justified as credit markets have normalized
- the two percentage point increase awarded to the non-taxable utilities should be removed
- consideration of CWIP and lower tax rate in the credit metric analysis was not necessary

270. The Commission dealt with these recommendations in the sections above. In addition to these recommendation, Drs. Kryzanowski and Roberts suggested further reductions to equity ratios awarded in 2009 decision for certain utilities.

271. In particular, the UCA witnesses recommended that ENMAX TFO's equity ratio be set at 30 per cent, which is three percentage points lower than the EPCOR TFO's common equity ratio. The basis for Drs. Kryzanowski and Roberts' recommendation was that ENMAX Transmission had lower asset growth as compared to other TFOs in the province, and as such, its business risk (in particular, the asset replacement risk) was lower.[188]

272. Additionally, Drs. Kryzanowski and Roberts recommended differentiating the common equity ratios of ATCO Electric TFO and AltaLink. According to the UCA witnesses' calculations, taking into account the relief measures provided in Decision 2011-134,[189] a 34 per cent equity ratio was sufficient to maintain ATCO Electric's credit metrics above the minimum levels.[190]

273. Drs. Kryzanowski and Roberts also recommended that the equity ratio for ATCO Gas be set at 34 per cent, which was one percentage point lower than their suggested equity ratio for

[188] Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, page 81.
[189] Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.
[190] Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraphs 139-143.

electric distribution companies. The UCA witnesses indicated that the lower ratio for ATCO Gas reflects the reduction in business risk from its weather deferral account.[191]

274. Finally, the UCA pointed out that Drs. Kryzanowski and Roberts recommended a 90 basis point flexibility adjustment to the allowed return on equity to further ensure that the utilities are capable of maintaining a credit rating in the A range.

275. The Utilities argued that there was no legitimate basis for distinguishing between the capital structures of ENMAX and EPCOR TFOs. As well, the Utilities submitted that the evidence in this proceeding did not support the view that ATCO Electric TFO and AltaLink should have different common equity ratios on a generic basis. The Utilities submitted that both of these proposals violated the standalone principle. In addition, the Utilities argued that any individual differences among the awarded common equity ratios should be made on company specific basis as part of the GTA process, and not during the GCOC process.

Commission findings

276. The approach of UCA and Drs. Kryzanowski and Roberts of adding 90 basis points to a common ROE in support of credit metrics presents some difficulties for the Commission.

277. In Decision 2004-052, the Commission's predecessor applied a generic ROE to all utilities and addressed the need for any utility-specific adjustments to the common ROE through the capital structure. Moreover, the board indicated that unique utility specific adjustments to the common ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular utility.[192]

278. In Decision 2009-216, the Commission reiterated that it will adjust for any differences in risk among the utilities by adjusting their individual equity ratios.[193] The Commission has reaffirmed its adherence to this approach in this decision as well. As such, the UCA's approach to add 90 basis points to the ROE on order to support an A category credit rating contradicts the approach taken by the Commission.

279. Additionally, the UCA's proposal makes it difficult to compare its recommendations to those of the other participants or even to the 2009 GCOC decision. In order to assess the UCA's ROE recommendation on a comparable basis, one could perhaps deduct the 90 basis points adder. But this was not the position of the UCA and so the Commission does not favour this approach. Besides, if the Commission were to deduct the 90 basis points from the UCA's ROE recommendation, it is not clear what amount, if any, should be added to the UCA's equity ratio recommendations. Furthermore, the UCA did not present any analysis to show that an adder to the ROE was a more cost effective way to support an A range credit rating than adjusting to a higher equity ratio.

280. Given these considerations, the Commission has evaluated the UCA's ROE and equity ratio recommendations as if they were independent of each other.

281. The UCA's credit metric analysis and resulting recommendations on the common equity ratios for the Alberta utilities were based on the assumptions that CWIP and lower income tax

[191] Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraph 414.
[192] Decision 2004-052, pages 14 and 15.
[193] Decision 2009-216, paragraph 78 and 221.

rates are not included in the credit metric calculations.[194] As detailed in Section 5.3.2 above, the Commission did not agree with this premise.

282. Furthermore, the UCA's approach of differentiating capital structures of ENMAX and EPCOR TFOs, ATCO Electric and AltaLink TFOs, as well as further distinguishing between the capital structures of ATCO Gas and AltaGas, runs contrary to the Commission findings in Section 5.4 above and the UCA's own evidence that business risks have not materially changed since 2009.[195]

283. For example, the UCA indicated that its recommended equity ratio for ATCO Gas of 34 per cent was one percentage point lower than equity ratio of electric distribution companies due to the reduction in business risk from its weather deferral account. However, the Commission already considered this matter when determining the common equity ratios in 2009. As presented in Decision 2009-216, the Commission acknowledged the existence of the weather deferral account and determined that that ATCO Gas has a similar level of business risk compared to electric distribution companies.[196]

284. More importantly, Drs. Kryzanowski and Roberts acknowledged that their proposed equity ratios for ENMAX Transmission and ATCO Pipelines (in 2012), were inconsistent with the minimum equity ratios observed by the Commission.[197]

285. For these reasons, the Commission does not accept the UCA's recommendations regarding further reductions in equity ratios for ATCO Electric and ENMAX TFOs, as well as ATCO Gas.

5.6 Conclusion regarding required capital structures

286. The Commission has examined a number of factors that are relevant to determining the required equity ratios. These include a consideration of the recent developments in credit environment, the levels of key credit metrics that are associated with the actual credit ratings of relatively pure-play Canadian utilities, and certain utility-specific adjustments.

287. Two factors that could potentially impact the electric transmission sector were also examined; the impact of above historic trend growth and any risk associated with the potential for stranded transmission assets. Finally, several other factors specific to certain individual utilities were examined. These included the non-taxable status of a number of the utilities, the competitive situation facing ATCO Pipelines following its integration with NGTL, and differentiation of equity ratios among certain utilities as proposed by the UCA.

288. Accordingly, the Commission makes the following findings:

1. There is no need to reverse the adjustment to the Alberta utilities' capital structure that was provided in Decision 2009-216 to account for the financial crisis, because the effects of the financial crisis have not completely abated.

194 Exhibit 210.02, UCA argument, paragraph 222.
195 Exhibit 81.02, prepared testimony of Drs. Kryzanowski and Roberts, paragraphs 238 and 286.
196 Decision 2009-216, paragraphs 368, 371 and 412.
197 Ibid., paragraph 221.

2. The credit metric analysis of relatively pure-play Canadian utilities indicates that in order to target a credit rating in the A range: (i) the minimum equity ratio for Alberta utilities should be 37 per cent based on EBIT analysis, 30 to 38 per cent based on FFO/debt analysis and 35 per cent based on FFO interest coverage analysis; (ii) the minimum equity levels produced by the credit metric analysis in this decision are somewhat higher than the equity ratios estimated in Tables 13 to 15 of Decision 2009-216, however (iii) since the equity ratios approved in the 2009 GCOC decision meet or exceed the minimum levels recommended above, no across-the-board increase to the currently approved equity ratios for the Alberta utilities is required.

3. The business risk analysis does not indicate that there have been major changes in the relative risks of the various utilities segments, with the exception of ATCO Pipelines following its integration with NGTL. Hence, as in the case of the 2009 decision, any increase in equity ratios should be relatively uniform across the sectors and individual utilities unless utility-specific considerations require otherwise.

289. Given the Commission determinations with respect to the effects of the financial crisis, the results of the credit metric analysis, and the Commission's finding that the relative risks of the various utilities segments have not changed, the Commission finds that no across-the-board increase to the currently approved equity ratios for the Alberta utilities is necessary.

290. The Commission will now consider the need for any company-specific adjustments to equity ratios.

ATCO Electric and AltaLink TFOs

291. As discussed earlier in this decision, recognizing the need to mitigate the impacts of the large capital build on ATCO Electric TFO and AltaLink TFO credit metrics, the Commission recently approved relief measures for these two companies in Decision 2011-134 and Decision 2011-453, respectively. These measures included the suspension of the current accounting treatment for CWIP (also known as CWIP in rate base) and approval for the future income tax method.

292. However, the credit metric relief packages approved for these transmission companies were based on the 2009-2010 approved ROE level of nine per cent, not the 8.75 per cent ROE approved in this decision for 2011 and 2012. With this reduction in the level of allowed return, the Commission considers that these two TFOs will not be afforded the level of relief intended in those decisions. In order to maintain the level of relief intended in Decision 2011-134 and Decision 2011-453, the Commission awards a one percentage point equity increase in the capital structure of ATCO Electric TFO and AltaLink TFO.

ATCO Pipelines

293. As detailed in Section 5.5.3 above, ATCO Pipelines' equity ratio for 2011 would be reflective of any common adjustments applicable to all utilities, but without considering the impact of integration. Therefore, ATCO Pipelines is awarded a 45 per cent equity ratio for 2011, unchanged from its currently approved level.

294. In 2012, ATCO Pipelines' equity ratio is set at 38 per cent, which represents the mid-point between the awarded equity ratios for the electric transmission and electric distribution sectors (without considering the extra adjustment for the tax-exempt utilities).

Table 10. Equity ratio findings

	Last approved (%)	2011 approved (%)	Change in approved common equity ratio (%)
Electric and Gas Transmission			
ATCO Electric TFO	36	37	1
AltaLink	36	37	1
ENMAX TFO	37	37	no change
EPCOR TFO	37	37	no change
RED Deer TFO	37	37	no change
Lethbridge TFO	37	37	no change
TransAlta	36	36	no change
ATCO Pipelines	45	45 for 2011 38 for 2012	no change for 2011 (7) for 2012
Electric and Gas Distribution			
ATCO Electric DISCO	39	39	no change
ENMAX DISCO	41	41	no change
EPCOR DISCO	41	41	no change
ATCO Gas	39	39	no change
FortisAlberta	41	41	no change
AltaGas	43	43	no change

5.7 Future adjustments to capital structure

295. The equity ratios awarded in this proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.

6 Management fee matters

6.1 Background

296. The Utilities proposed a management fee as compensation for the provision of service involving assets funded by customer contributions in aid of construction (CIAC). The concept of a management fee had been previously proposed by ATCO Electric in its 2009-2010 General Tariff Application (Proceeding ID No. 86) and AltaLink in its 2009-2010 TFO Tariff Application (Proceeding ID No. 102). The proposed management fee applied for in those applications was intended to provide compensation for the risks and value of service associated with ownership, operation and maintenance of assets financed by CIAC. In Decision 2009-087[198] in respect of ATCO Electric's 2010-2011 General Tariff Application, the Commission stated:

> The Commission finds that consideration and evaluation of CIAC and related compensation to the utility could be more efficiently and effectively addressed going forward at a generic proceeding, which would allow for a more detailed review of all

[198] Decision 2009-087: ATCO Electric Ltd., 2009-2012 General Tariff Application – Phase I, Application No. 1578371, Proceeding ID. 86, July 2, 2009.

relevant issues at one time by all potentially affected parties. The Commission will advise all parties in the near future as to the process that will be established.[199]

297. The Commission issued a similar finding in Decision 2009-151[200] in respect of AltaLink's 2009-2010 TFO Tariff Application.

298. By letter dated December 16, 2010, the Commission determined that the consideration of a management fee would be included in the scope of this proceeding.

299. The Utilities engaged Ms. McShane to assist in developing its position in respect of the proposed management fee. Ms. McShane provided the following conclusions in her evidence in respect of the proposed management fee:

- The proportion of CIAC to total regulated assets for the Alberta Utilities in the composite is materially higher than for the typical non-Alberta utility.
- CIAC relates to assets that are constructed, owned, managed and operated by the utilities, but for which no compensation in the form of return, margin or fee is provided, despite the fact that the utilities bear risks related to them.
- The root cause of the size of the CIAC is the existing investment and contribution policies. Amending investment policies is required but the mitigation will only occur over time and the Alberta Utilities should be afforded compensation for services rendered with respect to facilities funded in whole or in part by CIAC.
- The approach adopted to determine the amount of compensation that is reasonable for CIAC funded assets has been derived from the increase in the cost of equity that results from the reduction in the utilities' effective equity ratio due to the presence of debt-like CIAC. The compensation determined from this analysis, estimated as a return on CIAC, is two per cent. For taxable utilities the two per cent margin needs to be grossed up for income taxes to allow the utilities to earn the two per cent margin on an after-tax basis. The two per cent estimated return is supported by applying the approach used in the past by the Ontario Energy Board (OEB) to derive a reasonable return for deferred tax balances.
- The proposed two per cent return would be applied to CIAC balances that exceed four per cent of total rate base, inclusive of CIAC. The four per cent threshold was based on the average contributions as a per cent of gross rate base for nine non-Alberta regulated utilities as provided in Table 1 of Ms. McShane's evidence.
- The existing capital structures and ROE's, which were awarded in the absence of any consideration of CIAC, do not provide any compensation for CIAC.[201]

300. Ms. McShane stated that, in the absence of significant rate base upon which to determine a reasonable return, regulators have adopted alternative methodologies to provide a measure of return to the regulated utilities and noted the following examples:

199 Decision 2009-087, paragraph 38.
200 Decision 2009-151: AltaLink Management Ltd. And TransAlta Corporation, 2009 and 2010 Transmission Facility Owner Tariffs, Application No. 1587092 and Application No. 1594573, Proceeding ID. 102, October 2, 2009.
201 Exhibit 86.01, opinion on management fee and Rider I, lines 27-73.

- The Commission and its predecessors have adopted the concept of a return margin in the case of regulated rate tariffs where there is little rate base.
- The Independent Assessment Team[202] recommended the adoption of a minimum return margin in respect of the power purchase agreements related to the heritage electricity generation plants to address the issue of rising operating leverage as the generating plants reached the end of their accounting lives.
- The Federal Energy Regulatory Commission (FERC) adopted a management fee in cases of pipelines that are largely depreciated.[203]

301. Ms. McShane stated that the point of departure for the recommended approach is the recognition that (1) the higher the level of CIAC relative to the total rate base, the higher is the operating leverage; and (2) the higher the level of CIAC relative to total capital (inclusive of CIAC) the higher is the financial risk. Ms. McShane noted that operating leverage referred to the sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs.[204]

302. The Utilities' management fee proposal centered, however, on the issue that CIAC relates to assets that are constructed, owned, managed and operated by the Utilities, but for which no compensation in the form of return, margin or fee is provided despite the fact that the Utilities bear risks related to these assets and use them to provide valuable services.[205]

303. Conceptually, the management fee proposed by the Utilities involves a fee that would be included in the revenue requirement calculated as two per cent of each utility's remaining unamortized CIAC balance in excess of four per cent of its total assets. The Utilities summarized the calculation of the annual management fee in their argument as follows:

> The annual Management Fee should be calculated by (1) summing the mid-year approved CIAC balance and rate base net of other forms of no cost capital (i.e. mid-year pro-rated invested capital); (2) calculating 4% of the total; and (3) subtracting the 4% from the forecast test-year CIAC balance. The resulting balance equals the CIAC eligible for Management Fee. The management Fee in dollars for each of the Alberta Utilities would then be calculated by applying the requested 2% to the eligible CIAC balance. For the taxable utilities, the resulting Management Fee would then be grossed up by the test year corporate income tax rate.[206]

304. The UCA engaged Mr. William B. Marcus to assist in developing its position in respect of the proposed management fee, among other things. Mr. Marcus, in his evidence, submitted that he is opposed to the proposed management fee for the following reasons:[207]

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202 The Independent Assessment Team (IAT) was appointed under provisions included in April 1998 amendments to the *Electric Utilities Act*. The scope and duties of the IAT were set out in the *Electric Utilities Act*, and were focused on two major areas: assessment and determination of the PPAs, and design of the auction process (see Decision U99073: Board Review of the Independent Assessment Team's Report on Power Purchase Arrangements and other Determinations (Issued: August 30, 1999)).

203 Exhibit 86.01, opinion on management fee and Rider I, lines 234-265.

204 Exhibit 86.01, opinion on management fee and Rider I, lines 361 to 366.

205 Exhibit 86.01, opinion on management fee and Rider I, lines 216-224.

206 Exhibit 209.01, Utilities argument, paragraph 260.

207 Exhibit 81.04, prepared testimony Mr. William B. Marcus, pages 43 and 44.

- It upsets the regulatory compact, where a utility earns a return on invested capital commensurate with the company's business and financial risk, by providing a return on capital that the utility does not actually invest, even though the business and financial risks of the entire company – including contributed property –have already been considered when setting the capital structure and return on equity.
- The proposal made by utilities in the past completely negates the purpose of CIAC by forcing ratepayers to pay the same equity return on contributed property as they would pay had the utility simply put everything in rate base and had no contribution policy at all. All that is saved is the cost of debt.
- Giving shareholders an equity return on contributions without requiring them to actually invest any equity will enrich shareholders far more than if contributions were simply abolished. This comparison shows that paying an equity return on contributions will provide shareholders with an outsized and unreasonable return.
- What is actually being "managed" for contributed property is O&M expense. These expenses and the cost and risk of managing these expenses are included in rates, and the increase in contributions has not resulted in a significant increase in the utilities' total business risk.
- A management fee for contributions is a solution in search of a problem. Alberta has had high levels of distribution contributions literally for decades. Contributed transmission property has increased somewhat in recent years but is still on the order of 10 per cent of total transmission assets. Many of those assets are in fact contributed by the distribution company.

305. By letter dated August 5, 2011 the Commission set out a final issues list for argument and reply. The management fee section of this decision addresses the issues in respect of the proposed management fee as set out in Attachment 1 to the Commission's August 5, 2011 letter.

6.2 Views of the parties

6.2.1 Is a management fee compatible with the fair return standard and the paradigm of paying a return on capital invested in rate base?

306. The Utilities argued that the proposed management fee provides the utilities with fair compensation for providing valuable services and bearing the risks associated with the construction, ownership, operation and management of CIAC-financed assets and submitted that parties objecting to the management fee have ignored the unfairness arising from the utilities' obligation to provide services in relation to CIAC-financed assets for no compensation.

307. The Utilities also argued that the management fee is compatible with the legal framework as well as the fair return standard and that it provides for fair compensation for utility services rendered. Finally, the utilities stated that the management fee constitutes a fee or a just and reasonable charge for service rather than a fair return, which is legally separate and compensates the utility for something different. The Utilities stated that the two concepts, though independent of each other, are complementary.[208]

[208] Exhibit 209.01, Utilities argument, paragraphs 162 to 165.

308. The UCA submitted that the type of management fee proposed by Ms. McShane on behalf of the Utilities is not consistent with the fair return standard or the paradigm of paying a return on capital invested in rate base. The paradigm is cost-based rates, the UCA submitted, under which utilities are permitted to charge rates that will give them a reasonable opportunity to recover their prudently incurred costs, including the cost of the debt and equity capital they have invested in the business.[209]

309. The UCA argued that CIAC collected from customers by the Utilities represents capital that has been invested by the Utilities that has no cost associated with it. By effectively allowing shareholders to earn a return on the no-cost capital contributed by third parties, the UCA submitted, the management fee proposed by the Utilities would enable the Utilities, and ultimately their shareholders, to earn amounts in excess of their costs, including a fair return on the equity capital that has been invested by shareholders.[210]

310. The CCA agreed with Mr. Marcus and submitted that a management fee is incompatible with a fair return standard on invested capital. The CCA considered that the use of a management fee and a fair return on rate base and construction work in progress, or plant held for future use, results in excessive returns to the utility. The CCA also agreed with Mr. Marcus that a management fee is inconsistent with cost-based rate-making principles and it is inappropriate to award a utility a return, in the form of either a return on investment or a management fee, on the assets financed by customers.[211]

311. IPCAA submitted that the Utilities are asking to be compensated as if they had invested in the customer contributed facilities they are managing. Where facilities have been paid for by customers through customer contributions, rather than by the utility, IPCAA submitted that there is no equity injection by the utility and no concomitant risk accompanying such an investment. IPCAA submitted that the management fee proposal before the Commission is incompatible with the fair return standard and the paradigm of paying a return on capital invested in rate base.[212]

312. IPCAA submitted in reply argument that the Utilities receive cost of service compensation for the operation, maintenance and 'management' of CIAC-financed assets, so the Utilities statement in argument that "the Utilities receive no compensation relating to CIAC-financed assets" is incorrect and that compensation may or may not include a profit component. The Utilities, IPCAA submitted, as with all utilities in Alberta (and almost all of North America) are regulated on a cost of service basis and receive recovery of all reasonably incurred costs for services rendered. The Utilities receive such compensation for all CIAC assets, IPCAA argued, and no other form of compensation is warranted or indeed permitted.[213]

313. IPCAA noted that the Utilities themselves state, with respect to the risk of stranded TFO assets, that "the regulatory compact in Alberta has been such that tariffs are to, and do, provide the opportunity to recover the costs of prudent investments in the system." IPCAA stated that the Utilities make IPCAA's point; that there is nothing in the regulatory compact which allows a utility to recover compensation over and above its prudent costs of services provided. Profit is

[209] Exhibit 210.02, UCA argument, paragraph 232.
[210] Exhibit 210.02, UCA argument, paragraph 232.
[211] Exhibit 211.01, CCA argument, paragraph 59.
[212] Exhibit 212.01, IPCAA argument, paragraph 17 and 18.
[213] Exhibit 222.01, IPCAA reply argument, paragraph 2.

possible on investments, just as the Utilities note, and only on investments. IPCAA submitted that utility investment has always been net of CIAC investment.[214]

314. IPCAA stated that services such as providing operations and maintenance services have been paid by the cost recovery of operation and maintenance expenses, excluding a profit component. All the items of allowable costs are set out in Section 122(1) of the *Electric Utilities Act.* This reflects the regulatory compact as it exists in Alberta, and it is this compact that the Utilities appear to want to defend on the one hand (with respect to the risk of stranded TFO assets) and undermine on the other hand (in the context of a management fee).[215]

315. CAPP submitted that the Utilities argument that a management fee is separate from the fair equity return to be allowed the equity investor is paradoxical since the management fee is nothing more or less than compensation to the equity investor. It is the equity investor that is the intended recipient of the fee and the result is to increase the return to the equity investor. CAPP submitted that gas utilities like ATCO Pipelines have been collecting customer contributions for decades without it ever being suggested that the equity investor was being short changed. If utility equity investors were being short changed all these many decades it would have been evident in market data long before now.[216]

316. In reply, the Utilities countered the assertions made by IPCAA and CAPP that the Utilities are compensated for costs incurred in respect of CIAC assets by stating that mere cost recovery is not compensation for valuable services rendered. The Utilities agreed that, where CIAC levels approximate the industry average, the conventional model generally provides fair and reasonable compensation. However, the Utilities noted that CAIC levels are significantly higher in Alberta than the industry average and, as a result, the paradigm does not provide fair compensation, or any compensation, in relation to services provided and risks borne in relation to CIAC-funded assets. The Utilities reiterated that the proposed management fee augments the conventional model, it does not supplant it.[217]

6.2.2 Does the Commission have the jurisdiction under its governing legislation to provide for a management fee?

317. The Utilities argued that the proposed management fee addresses a fundamental issue of fairness and that, consistent with the fundamental principles of utility regulation and the regulatory compact, regulated entities should not be expected to provide service to customers for zero compensation.[218] Consequently, the Utilities asserted that they should be fairly compensated for the risks undertaken and the services provided to ratepayers using CIAC-financed assets.

318. With regard to the Commission's jurisdiction to award a management fee, the Utilities referred to sections 121(2) and 122(1) of the *Electric Utilities Act as* establishing the basis for a utility to recover costs and expenses associated with the provision of necessary services to customers.

319. The Utilities argued that CIAC assets are indistinguishable from other utility assets and so the Utilities should be provided an opportunity to earn fair compensation for services the

214 Exhibit 222.01, IPCAA reply argument, paragraph 3.
215 Exhibit 222.01, IPCAA reply argument, paragraph 4.
216 Exhibit 217.02, CAPP reply argument, paragraphs 19, 20, and 21.
217 Exhibit 220.02, Utilities reply argument, paragraphs 109-111.
218 Exhibit 209.01, Utilities argument, paragraph 163.

Utilities are mandated to provide using CIAC-financed assets. The Utilities stated that the Commission should approve the management fee consistent with the Commission's statutory obligation to provide just and reasonable compensation per Section 121(2)(a) of the *Electric Utilities Act*.

320. With respect to gas utility-related legislation, the Utilities cited Section 4(3) of the *Roles, Relationships and Responsibilities Regulation* as the basis for a gas utility's recovery of costs and expenses associated with the provision of necessary services to customers and stated that sections 36(a) and 45 of the *Gas Utilities Act* contemplate that regulated utilities will receive reasonable compensation for the services they provide.

321. The Utilities took issue with the interveners' characterization of the management fee as a return on monies not invested, stating that the Utilities are instead requesting fair compensation in the form of a separate fee or just and reasonable charge commensurate with the value of services rendered that is distinguishable from fair return.

322. The Utilities argued that the right to be fairly compensated for services provided to ratepayers through the use of utility assets is a fundamental underpinning of the regulation of utilities, and has been previously recognized by the Courts. In contrast to the position of interveners, the Utilities argued the presence of cost of service references in the legislation does not preclude the Commission from awarding a management fee.

323. Even in the absence of any statutory provision, the Utilities stated that consumers would have imposed upon them an obligation at common law to pay for the service on the basis of *quantum meruit*, as part of the undoubted jurisdiction to ensure that tolls are at all times just and reasonable. In support of this, the Utilities cited the Supreme Court of Canada's decision in *City of Edmonton et al. v. Northwestern Utilities Ltd*:[219]

> The right of the consumers to require the respondent to supply them with gas, conferred by the statute, would, in my opinion, <u>even in the absence of any statutory provision, impose upon them an obligation at common law to pay for the service on the basis of quantum meruit</u>. In such circumstances, I consider that the position of the utility would be similar to that of a common carrier upon whom is imposed, as a matter of law, the duty of transporting goods tendered to him for carriage at fair and reasonable rates. (Great Western R. Co. v. Sutton (1869), L.R. 4 H.L. 226 at 237). Here the duty of determining what rates are fair and reasonable is imposed upon the board.(…) [Emphasis added.]

324. The Utilities cited *Sullivan on the Construction of Statutes* to support the position that there exists a presumption that legislation is not intended to alter the common law but that the common law is meant to be incorporated. Absent clear legislative intent to the contrary, the Utilities argued, a utility has the right to receive just and reasonable compensation for providing services that it is legally obligated to provide.

325. Accordingly, the Utilities stated that:

> (E)ven if one were to ignore the provisions of applicable legislation, which provide for fair compensation for utility services rendered and obligate the Commission to ensure

[219] *City of Edmonton et al. v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 at 401(*Northwestern 1961*).

> that tariffs are just and reasonable, the Utilities are entitled to fair compensation based on principles of *quantum meruit*, for value of service rendered. Yet, the current treatment of CIAC does not provide any compensation to the Utility, let alone fair compensation dictated by the common law principles of *quantum meruit*, which is also encompassed in the legislative requirement that rates be just and reasonable.[220] [footnotes omitted]

326. In response to the question of whether the Commission has the jurisdiction under its governing legislation to provide for a management fee, the UCA noted that the general approach of limiting utility rates to a cost-based level has been developed and applied by North American utility regulators, including the Commission, for some time. The UCA stated that, in many jurisdictions, the governing statutory requirement is simply that rates be just and reasonable, and not unjustly or unduly discriminatory. In those jurisdictions, the UCA submitted, the legislature has left the determination and definition of the "just and reasonable" standard to the regulators.

327. The UCA distinguished the situation in Alberta, where it argued that the legislature has gone further and codified a requirement for conventionally determined cost-based rates in the relevant statutes. The UCA noted that, under Section 90 of the *Public Utilities Act*, in order to fix just and reasonable rates, the Commission is required to determine a rate base for the property of the owner of the public utility that is used or required to be used to provide service to the public, and fix a fair return on that rate base. The UCA also cited Section 122 of the *Electric Utilities Act* which states that, when considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of the electric utility with a reasonable opportunity to recover the costs and expenses associated with the capital related to the owner's investment, including a fair return on the equity of shareholders of the utility as it relates to the investment.

328. The UCA argued that conventionally determined cost-based utility rates are not only just and reasonable, as a matter of economic and regulatory theory, but are therefore also required by the relevant Alberta statutes. To the extent a management fee would enable the utilities to recover, on an expected basis, amounts in excess of their costs, including a fair return on equity, the UCA submitted that such a fee is not permitted by the statutes.

329. The UCA also noted the Utilities' argument that the principle of *quantum meruit* operates, notwithstanding the provisions of the *Electric Utilities Act* and *Gas Utilities Act*, to give the Utilities a common law or equitable right to compensation for the value of services provided using CIAC-financed facilities in addition to their statutory right to charge rates that enable them to recover their costs, including a fair return.

330. The *quantum meruit* principle, the UCA submitted, is an equitable doctrine that enables the Courts, based on specific factual circumstances, to award compensation for services rendered in situations where the person providing the service should be entitled to receive some level of compensation on "equitable grounds" and is not entitled to any compensation under contract, statute, or on other legal grounds. The UCA argued that the Utilities do not provide any services that they are not compensated for, and the compensation they receive is set at a level that meets the requirements of the applicable statutes. Thus, the UCA submitted, there are no uncompensated-for services for the *quantum meruit* principle to apply to.

[220] Exhibit 209.01, Utilities argument, paragraph 176.

331. The UCA took issue with the notion that the Utilities appeared to be suggesting that the *quantum meruit* principle applies not just to whether they receive compensation for services they provide, but to the level of that compensation. The UCA argued that to claim that the principle provides for a common law or equitable right to require the Commission to set rates at a level that is higher than a cost-based level, if the value of the services provided by the Utilities exceeds the cost of providing them, is inconsistent with the *Electric Utilities Act* and the *Gas Utilities Act* as well as the *Northwestern* decision and cannot be correct.

332. Approval of the management fee proposal would, the UCA argued, result in rates that are higher than are necessary to enable the Utilities to recover their prudently incurred costs, including a fair return. It would also, the UCA argued, result in profits or returns to shareholders that exceed the cost of equity capital and the levels dictated by the fair return standard, and it would result in rates that are not just and reasonable under any normal conception of that expression.

333. The CCA submitted that a management fee and return on invested capital results in excessive returns to the utility and that the awarding of an excessive return in the form of a management fee and return on invested capital is beyond the AUC's jurisdiction.

334. IPCAA submitted that the Commission did not have the jurisdiction to award the management fee in the form requested by the Utilities, as such a fee would only be justified if the Utilities had made an equity injection with respect to the subject facilities. IPCCA argued that Section 122(1) of the *Electric Utilities Act* did not support the Utilities' proposal as the Utilities already received cost recovery under those provisions. IPCAA argued that the management fee as proposed would grant recovery over and above the costs and expenses incurred by the Utilities in managing these facilities and that is not permitted under Section 122. IPCAA also disagreed with the Utilities' argument that the Commission "should approve the Management Fee, consistent with the Commission's statutory obligation to provide just and reasonable compensation per section 121(2)(a) of the *EUA*," stating that Section 121 was a general section, the type seen in virtually all similar statues.

335. IPCCA stated that the Utilities' arguments that "compensation commensurate with value of service rendered is a common law right" and that "regulated entities have never been expected to provide service to customers for no compensation" ignore both the compensation the Utilities receive for 'managing' CIAC assets and the law. IPCAA submitted that the regulatory compact, as reflected in the *Electric Utilities Act*, compensates utilities for services performed on the basis of the cost of service model and that, conversely, return of and on equity is precisely that; namely, return on the equity component of capital invested by the utility, and no more profit beyond that.

336. Arguing that the Utilities' statement that the "net rate base model focuses solely on the concept of cost of service, with no consideration given to the value of the services provided" is misleading, IPCAA submitted that it was more accurate to say that the cost of service model is used as a proxy for the value of services rendered by a utility.

337. IPCCA also argued that the Utilities' management fee proposal runs contrary to the regulatory compact and could equally apply to all other costs incurred by utilities in providing service. As an example, IPCCA noted that the cost of debt has always been recovered on a cost of service basis with no component for profit. If the Utilities' "illogic" was followed, IPCAA

argued, then investment covered by debt is also a "valuable service" and should be entitled to a profit in addition to the recovery of debt costs.

338. CAPP submitted that utility investors are allowed a return of and on their investment and that the law does not allow utility investors to get a return on money they have not put into the business. CAPP argued that the modern regulatory statute completely replaces the common law with regard to payment for utility services. The fair and reasonable compensation for common carriers under common law spoken of by Justice Locke in *Northwestern 1961*, CAPP argued, is now not a matter of *quantum meruit* as that may be measured by a judge in a civil action, but is to be determined in accordance with the principles established by statute by expert regulatory commissions.

339. The rate of return/rate base model is the law in Alberta, CAPP argued, which means equity investors earn a return on their equity investment, while debt investors earn a return on their debt investment. CAPP noted that the equity investor does not get a return for the management of the assets funded by debt: neither does the debt investor get a return for the management of the assets funded by equity. Likewise, CAPP argued, neither the law nor the model allows for a return on money that comes cost free from the customer. CAAP submitted that there is no unfairness in that, just as there is no unfairness in the equity investor getting, to paraphrase Ms. McShane, "zero profit" on the debt.

340. CAPP argued that the Utilities provide no legal authority that would suggest that the legislated scheme of rate-of-return/rate base regulation fails to set a reasonable price for service. Moreover, such an argument would go to the roots of the legislation and could not be confined to one issue like management fees.

341. CAPP submitted that what the utility gets for managing the assets, over and above the rate of return on rate base, is the recovery of all proper costs of operating the system. CAPP cited *Northwestern 1961* in support of the concept that the return on the capital invested by the investor is "net":

> In approving rates which will yield a fair return to the utility upon its rate base, it is, of course, essential for the Board to estimate the expenses which will necessarily be incurred thereafter in rendering the service. The fair return permitted is, after deducting from the gross revenue these necessary estimated expenditures and such necessary outgoings as taxes, including income taxes. The Board can only come to a conclusion as to what rates should be approved by determining as closely as may be done in advance the probable amount of these expenditures.[221]

342. Citing *Stores Block*, CAPP submitted that the entire discussion in that decision is premised on investment by private investors, not by customers, as is clear from the following passage:

> The capital invested is not provided by the public purse or by the customers; it is injected into the business by private parties who expect as large a return on the capital invested in the enterprise as they would receive if they were investing in other securities possessing equal features of attractiveness stability and certainty (see *Northwestern 1929*, at p. 192). This prospect will

[221] *Northwestern 1961* at page 405.

> necessarily include any gain or loss that is made if the company divests itself of some of its assets, i.e., land, buildings, etc.[222]

343. CAPP argued that, if the customers, in addition to contributing free capital to obtain service (and so lower rates than would otherwise have been the case if the utility had made the investment), were to be required to pay the equity investor a return to manage that customer's capital contribution then it calls into question the rationale of *Stores Block.*

344. CAPP submitted that it is only in those rare few cases of the vanished rate base that the management fee comes into play since, otherwise, the equity investor would receive no return. In such cases the management fee is a substitute for the return on equity capital. It may also be observed that, when the utilities cite such rare cases of vanished rate base as precedent, they completely contradict their argument that the management fee issue is separate and distinct from the fair return.

345. With respect to the Utilities' argument regarding *quantum meruit*, CAPP submitted that *quantum meruit* applies in common law to the provision of goods or services that have been provided in the expectation of payment and where there is no contract that applies to the price for those goods or service. In this case, CAPP argued, here is a contract for the provision of services by the utility to the customer and it is governed by the tariff approved by the regulator. The approved tariff specifies the price to be paid and the terms and conditions including when the utility is not obliged to finance an investment in plant and the customer must finance the investment with the customer's own capital.

346. CAPP submitted that the provision of customer contributions is a creation of the regulatory model: it is not something that stands outside the regulatory model that is governed by common law principles and there is no gap to be filled by common law principles. CAPP argued that judicial observations, in obiter dicta, to the effect that regulatory statutes are consistent with *quantum meruit*, a concept that applied to common carriers at common law, do not assist the Utilities' argument.

347. In reply argument, the Utilities noted that there was no disagreement that the Commission is charged with ensuring that, in setting rates, it provides the utility a reasonable opportunity to recover its prudently incurred costs, including a fair return on investor-supplied capital.[223] The Utilities asserted that an economic cost or opportunity cost, which reflects normal profit for the service rendered, is therefore recognized as legitimate for cost recovery: the Utilities noted return on equity as an example, citing *TransCanada Pipelines Limited v. Canada (National Energy Board)*, 2004, FCA 149, at paragraphs 6-12 and 32-34 as authority that such costs are recoverable in rates. The Utilities asserted that the management fee, like return on equity, is an economic cost as opposed to an incurred cost.[224]

348. The Utilities distinguished CAPP's discussion of the *Stores Block*[225] decision, stating that that decision dealt with a different matter (i.e., asset disposition not CIAC) and argued that it did not displace the utility's right in law to receive fair compensation commensurate with the value of services rendered.

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222 *Stores Block* at paragraph 70.
223 Exhibit 220.02, Utilities reply argument, paragraph 115.
224 Exhibit 220.02, Utilities reply argument , paragraph 117.
225 *ATCO Gas &Pipelines Ltd. v. Alberta (Energy &Utilities Board*), [2006]1 S.C.R. 140 (*Stores Block*).

6.2.3 Should the utilities receive a fee for management of contributed assets? If so, should a management fee be awarded in addition to the allowed rate of return or can the ROE be adjusted to include compensation for the management of CIAC? Alternatively, can the ROE remain constant and a management fee be awarded through adjustments to the debt/equity ratio of individual utilities?

349. The Utilities argued that CIAC funded assets are fully integrated into other regulated assets that the Utilities own and operate and that the services that the Utilities provide to the customers that make contributions are the same as for all other customers. The Utilities stated that the only difference is that the Utilities do not finance CIAC assets and do not receive any compensation, or margin, either for providing valuable services related to, or for bearing risks associated with, constructing, owning, operating, and managing those assets.[226] The Utilities submitted that they should earn a margin or fair compensation for all of the service they render using all of the assets employed in rendering such service.

350. In argument, the Utilities noted Ms. McShane's evidence that in a "real world" competitive market, a business would expect to be compensated for the totality of the resources that it deploys, including physical capital and labour and enterprise capital. Further, in competitive markets, in economic terms, firms expect to earn a normal rate of profit; where a normal rate of profit recognizes the opportunity costs of all the resources devoted to the business. Finally, the Utilities noted that there are numerous competitive industries that have very little invested debt and equity, because they are primarily service industries (a number of which were identified in response to UCA-Utilities-48). Firms in these industries would all expect to generate a profit from the services that they provide irrespective of the fact that there is little invested capital. And, like the Alberta Utilities, these firms would expect to generate a profit on the totality of their business, not just some of their business operations.[227]

351. The Utilities stated that the size of CIAC is a problem unique to Alberta and noted that, in aggregate, total unamortized CIAC of the Alberta Utilities in 2007 was approximately $1.3 billion out of a total rate base net of contributions of approximately $6.6 billion and that, based on 2010 estimated data, CIAC accounts for approximately 16 per cent of gross rate base. The Utilities stated that there is a significant disparity between the percentage of CIAC of the Alberta Utilities and that of their Canadian peers and noted that, for a typical regulated Canadian utility, the CIAC to total rate base percentage is less than four per cent.[228] In Table 1 of her evidence, Ms. McShane provided the following list of regulated Canadian utilities and their contributions as a per cent of gross rate base:

226 Exhibit 209.01, Utilities argument, paragraphs 181 and 182.
227 Exhibit 209.01, Utilities argument, paragraphs 184 to 186.
228 Exhibit 209.01, Utilities argument, paragraphs 187 and 188.

Table 11. Proportion of contributions to gross rate base for ex-Alberta utilities

Utility	Contributions as a Per cent of Gross Rate Base
Foothills Pipelines	0.6%
FortisBC	8.8%
Gaz Metro	3.9%
Maritime Electric	4.5%
Newfoundland Power	2.8%
PNG-West	3.8%
Terasen Gas	6.3%
TransCanada Pipelines	0.5%
Westcoast Energy	0.5%
Median	**3.8%**

352. The Utilities submitted that limiting the application of the two per cent margin to CIAC balances in excess of four per cent of gross (inclusive of contributions) rate base would appropriately recognize the fact that other utilities in Canada, that could be considered comparable to the Alberta Utilities, also have some CIAC, albeit in generally smaller proportions.[229] The Utilities noted that some level of contributions may be needed to help maintain fairness amongst customers but the current regime neglects to address the fairness issue as between customers and the Utilities. The Utilities refuted Mr. Marcus' assertion that the requested management fee would "negate" the purpose of contributions stating that receiving compensation where compensation is merited does not negate the purpose of contributions, since customers are not paying what they would pay if the CIAC-financed assets had instead been fully funded by investor supplied capital. The Utilities noted that a utility would not choose to construct, own, operate and manage assets on which it receives no profit margin but it has no choice since it is mandated to do so.

353. The Utilities stated that the management fee was recommended independently of the generic ROE and the capital structures appropriate for each utility, that it was a separate compensation from the fair return on rate base and that it would compensate the Utilities for something not compensated for under the existing cost of service regulatory scheme. The Utilities stated that the two concepts, fair return on rate base and the management fee, are complementary, with the management fee augmenting the traditional rate base/rate of return model to ensure fair compensation to the Utilities.[230] The Utilities noted that, during the oral proceeding, Ms. McShane confirmed that the need for a management fee arises because the traditional rate base/rate of return model does not fit the unique circumstances of the Alberta Utilities and does not afford adequate, or any, compensation for opportunity cost or value of service. The Utilities noted that, in addition to the value of services rendered, there are business risks and liabilities, other than the operating leverage risk, that the utilities are exposed to and for which the Utilities should be separately compensated in the management fee.

229 Exhibit 209.01, Utilities argument, paragraph 189.
230 Exhibit 209.01, Utilities argument, paragraph 194.

354. The Utilities took exception to Mr. Marcus' suggestion that, if the Commission is compensating for anything other than risk, then only a minimal amount should be awarded. The Utilities stated that the position advanced by Mr. Marcus downplays the risks taken and the value of services provided and the point that Mr. Marcus ignores is that the functions performed by the Utilities in relation to CIAC extend beyond operating and maintaining assets and included, for example, building transmission substations on, in effect, a turnkey basis for no compensation. Since constructing assets comprises a significant portion of activities associated with CIAC, the Utilities stated that this was further evidence that Mr. Marcus is undervaluing the services provided by the Utilities and that his "percentage adder on O&M" approach does not provide a reasonable estimate of that value.

355. The Utilities noted that IPCAA opposed the management fee on the basis that:

> IPCAA also believes the TFO's management fee proposal has an element of double charging. This potential for double charging is a matter of particular concern in the case of the customer who has already made a customer contribution since the additional management fee for the same assets adds no value.[231]

356. The Utilities submitted that IPCAA's reasoning is flawed and that there is no double charging since the Utilities do not recover the cost of capital provided by customers. Rather, the Utilities would now recover a fee for the valuable construction, operation and maintenance activities associated with continuing utility service.[232]

357. The Utilities noted that the Commission has previously acted to ensure that entities it regulates receive fair and reasonable compensation for the functions they perform and services they render in circumstances where the traditional cost of service methodology did not render appropriate results. The Utilities made reference to the retail energy providers who have little invested capital and are compensated by way of a return margin. In addition, the Utilities made reference to other jurisdictions in Canada and the U.S. where regulators have augmented the rate base/rate of return model in order to provide fair compensation to the utility. The Utilities noted that, while the circumstances of the Alberta utilities are not identical to those cited, the examples from these other jurisdictions provide a useful precedent for the regulatory approach the Utilities are proposing.[233]

358. The Utilities noted that Mr. Marcus acknowledged that, when the proportion of CIAC to total rate base becomes sufficiently large, the rate base/rate of return model may need to be replaced with an alternative.[234] The Utilities then stated that, as Mr. Marcus appears to agree with the concept of providing compensation or a margin for services rendered and risks assumed, the only disagreement appeared to be a question of how much CIAC is required to trigger payment of a service fee.[235]

359. In responding to the submission by various parties that contributions are already taken into account when setting the capital structure and return on equity, the Utilities stated that recovery of a utility's cost of capital does not address compensation for services provided

231 Exhibit 82.02, IPCAA Rider I evidence, pages 5 and 6.
232 Exhibit 209.01, Utilities argument, paragraphs 199 and 200.
233 Exhibit 209.01, Utilities argument, paragraph 202.
234 Exhibit 209.01, Utilities argument, paragraph 202.
235 Exhibit 209.01, Utilities argument, paragraph 203.

utilizing customer supplied capital. The Utilities stated that the recommended capital structure and ROE for the Alberta Utilities have been made independently of the issues related to CIAC. The Utilities submitted that there is no evidence the Commission or its predecessors have, either explicitly or implicitly, reflected the value of services provided with respect to, or risks related to, CIAC in setting the capital structures or ROE's in prior cost of capital decisions for Alberta Utilities.[236] They noted that the CIAC issue did arise with respect to AltaGas Utilities in the 2004 GCOC proceeding but stated that there was no reference to CIAC in the determination of relative business risk. Finally, the Utilities noted that the Commission determined that the management fee issue, when raised in other proceedings, should be considered on a more comprehensive industry wide basis in a subsequent proceeding. The Utilities stated that this was clear recognition from the Commission that the issue had not been previously determined.[237]

360. The Utilities addressed the fact that Interveners raised the timing of the management fee proposal and stated that no adverse inference can be drawn for the fact that the Utilities did not address the CIAC issue in prior cost of capital recommendations and that this simply reflected that, until recently, the Utilities attempted to deal with the CIAC issue through proposed changes to investment policy rather than seeking higher returns or thicker equity ratios.[238]

361. The Utilities stated that their position is that the management fee should be implemented as a separate revenue requirement item distinct from ROE and capital structure. The Utilities proposal maintains the traditional rate base/rate of return construct as regards investor supplied capital and, as such, the ROE must remain the same for each of the Utilities.

362. The Utilities also stated that implementing the management fee as a separate revenue requirement item would appropriately reflect the fact that the two concepts compensate for something different. The fair return relates to assets that are financed by the utility whereas the management fee relates to assets that are constructed, owned and operated by the utility but are financed by customers. As there is no overlap and the compensation for each is arrived at independently, there is no basis for accounting for the management fee through an adjustment to ROE. Accounting for it through ROE also loses the scalability feature of the management fee proposal which would award each utility a fee calculated only on the proportion of CIAC each utility has at any particular point in time.[239] Further, the Utilities submitted that there is no valid basis for reducing the allowed return on account of a management fee.[240] They also stated that while ROE and capital structures are assessed against "comparable" companies, those firms do not have the high levels of CIAC experienced by the Alberta Utilities, therefore, the fair return does not account for the CIAC assets.[241] Finally, treating the management fee as an offset would understate the fair return determined by the Commission applicable to investor supplied capital.[242]

236 Exhibit 209.01, Utilities argument, paragraphs 205 and 205.
237 Exhibit 209.01, Utilities argument, paragraph 210.
238 Exhibit 209.01, Utilities argument, paragraph 206.
239 Exhibit 209.01, Utilities argument, paragraphs 211 to 213.
240 Exhibit 209.01, Utilities argument, paragraph 214.
241 Exhibit 209.01, Utilities argument, paragraph 215.
242 Exhibit 209.01, Utilities argument, paragraph 216.

363. The Utilities noted that in evidence they had stated that the adoption of a management fee would have a *de minimus* impact on credit metrics and financial risk and added that any improvement would be insufficient to warrant offset to ROE or capital structure.[243]

364. The Utilities stated that the suggestion that CIAC be awarded through an annual adjustment to the debt/equity ratio of individual utilities was not a reasonable alternative and submitted that the deemed common equity ratio should remain constant as it is intended to be a relatively permanent proportion of the investor supplied capital to be changed only when the circumstances of the utility change materially.[244]

365. Finally with respect to changes to investment policies or Rider I, the Utilities submitted that these changes, if they occur, might result in the amount of the management fee declining over time but would not change the fact that there are significant contributions now over which services are being provided for no compensation.[245] The Utilities added that policy amendment, although necessary to restrict growth in contributions, is not a solution by itself and that as long as there remain substantial contributions outstanding there remains a need for a management fee.[246] The Utilities also stated that the proposed Rider I might offer some mitigation to TFOs but would not address the contributions that are made to the distribution utilities or gas utilities.[247]

366. The UCA argued that, under cost-based regulation, utilities are entitled to recover their costs of providing service through rates, and if the Utilities could show that CIAC gives rise to utility or shareholder costs or risks as recognized by the legislation, it may be appropriate to allow them to recover those costs through a management fee or other mechanism. However, the UCA argued, the Utilities have not shown that there are costs associated with holding CIAC balances, and they have not provided any other reasonable basis on which to impose such a fee.[248]

367. The UCA submitted that Ms. McShane had advanced three basic arguments in support of a management fee in her evidence, which it summarized as follows:[249]

a) CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders.

b) CIAC creates financial leverage that results in increased financial risk and an increase in the cost of equity for shareholders.

c) A management fee is appropriate as a matter of fairness in order to properly reflect the expectations of utilities and the value of the services that they provide.

Operating leverage

368. The UCA submitted that, in principle, the argument that CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders has

243 Exhibit 209.01, Utilities argument, paragraph 217.
244 Exhibit 209.01, Utilities argument, paragraph 219.
245 Exhibit 209.01, Utilities argument, paragraph 229.
246 Exhibit 209.01, Utilities argument, paragraph 226.
247 Exhibit 209.01, Utilities argument, paragraph 179.
248 Exhibit 210.02, UCA argument, paragraph 240.
249 Exhibit 210.02, UCA argument, paragraph 242.

some theoretical validity since CIAC can create incremental operational risk. However, the UCA submitted that in practice the numbers are very small, and in the actual circumstances of the Utilities the risk is *de minimus*, so any fee imposed to compensate for it would be trivial. Moreover, the UCA submitted that the Utilities already differ in the amount of operating leverage and risk that they bear without those differences ever having been recognized for rate making purposes, and there is no reason to recognize only risks associated with CIAC balances.[250]

369. The UCA submitted that the effect of CIAC is to magnify the effects of changes in operating costs, whether positive or negative, on the effective return. On an expected or probability-weighted basis, there is no impact on average shareholder returns, but in principle the variability of those earnings increases with CIAC. In principle, that increased earnings variability should increase the cost of equity slightly for the utility with assets financed with more CIAC. However, the UCA submitted that whether the reference point for the maximum shift caused by operating leverage is four or 40 basis points, it is still an extremely small effect. In response to examination by Commission Counsel, Mr. Marcus pointed out that the risk that is imposed by contributions is so small that it falls within the rounding error and the financial flexibility adjustments of all the witnesses who provided evidence in the proceeding.[251]

370. The UCA argued that the size of operating leverage effect illustrated in Table 2 of Ms. McShane's management fee evidence is a function of (a) the variability in operating costs, and (b) the size of the rate base on which a regulated return is earned. It has nothing to do with CIAC uniquely, but rather with the relationship between the variability of operating costs and the size of the rate base. The UCA submitted that, for all utilities, the size of the rate base is a function of numerous factors, only one of which may be CIAC. The UCA argued that the most obvious example of a non-CIAC determinant of rate base is accumulated depreciation.

371. Referencing Ms. McShane's Table 2, the UCA stated, if the label CIAC at the fourth line was instead relabelled "Accumulated Depreciation," then the first utility, being new, would have a rate base equal to gross plant, but the second utility, being several years older , would have recovered 20 per cent of its initial investment through depreciation charges. In that situation, all of the numbers shown in the table, and all of the effects of what is now labelled Accumulated Depreciation on the variability of earnings, are exactly that same as they were in the case where the second line was labelled CIAC. The UCA argued that it would not be reasonable to give the shareholders of the second utility a management fee just because they have recovered 20 per cent of their investment through depreciation charges, even though their position is no different from that of the shareholders of the second utility in Ms. McShane's table who recovered 20 per cent of the cost of the firm's facilities from contributing customers.[252]

372. The UCA submitted that, while in normal situations these types of differences in operating leverage exist all the time for different reasons, there are situations where operating leverage and the associated risk can become extreme, and where a management fee or equivalent mechanism may be reasonable. A clear example of that, the UCA submitted, is the High Island Offshore System (HIOS) case dealt with at the FERC. In that case, the HIOS regulated pipeline had had its rate base depreciated down to essentially nothing. In that situation, HIOS

[250] Exhibit 210.02, UCA argument, paragraph 243.
[251] Exhibit 210.02, UCA argument, paragraphs 249 and 250.
[252] Exhibit 210.02, UCA argument, paragraphs 252 and 253.

shareholders have no money invested in the business, and earn no return or profit, but are still exposed to risk related to variability in operating costs and revenues.

373. The FERC confirmed in the specific circumstances unique to the HIOS case that its policy is to allow the pipeline to earn a management fee roughly equal to the standard rate of return applied to a deemed rate base equal to about five per cent of the pipeline's original investment or gross plant. The UCA submitted that is a management fee that is very small, and moreover only available when the utility has reached a point where its shareholders are earning essentially a zero return. The UCA argued that this is an extreme and unique situation that is completely unlike the situation facing any of the Alberta Utilities.[253]

374. The UCA stated that the FERC made itself very clear in the HIOS case that the decision does not stand for the principle supported by the Utilities here that utilities should get *both* a rate of return and a management fee, contrary to the implication of Ms. McShane's testimony.[254] In rebuttal evidence, the UCA stated:

> 165 The FERC decisions have nothing to do with returns on pieces of a company (i.e., the Utilities claim that contributed plant should be treated as separate from plant funded by investors). The FERC decisions provide a methodology that applies only when the rate base paradigm does not provide an adequate return for the operational risk because rate base is zero or extremely low for a given company or plant. This point is made extremely clear in the HIOS Order on Rehearing, where FERC stated:
>
>> On the other hand, however, a large investment in a new HIOS project, similar to the $80 million invested in the non-jurisdictional East Breaks Gathering System, would *terminate the management fee* in favor of a return to the traditional return on rate base methodology.[255] [emphasis added] [footnotes omitted]

375. Another factor to be considered, the UCA submitted, is that these types of risks or costs must have existed for years or decades, because the average CIAC levels have been consistent over a long period. Before the management fee issue was raised relatively recently in the ATCO Electric and AltaLink proceedings, none of the Utilities had identified any risk or cost associated with CIAC or complained that they were not being appropriately compensated for those risks and costs, the UCA argued. Whatever effects CIAC has on utility cost of equity must have been already accounted for by the Commission.[256]

376. The UCA submitted in its rebuttal evidence that Ms. McShane has made an implicit assumption that the Commission and its predecessors never thought about risks created by CIAC and therefore must grant an increase equal to the full amount of her recommendation. The UCA submitted that, if in fact the regulators granted a return commensurate with the utility's business risks in past cases, then granting an increase in this case due to risk associated with the full amount of contributions will compensate the utilities twice for the same risk.[257]

377. Further, the UCA stated that it is unreasonable to assume that the alleged risks of contributions were never considered by the Alberta regulator, unless one also reaches the

[253] Exhibit 210.02, UCA argument, paragraphs 255-257.
[254] Exhibit 210.02, UCA argument, paragraph 258.
[255] Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 165.
[256] Exhibit 210.02, UCA argument, paragraph 265.
[257] Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 168.

conclusion that utility rate of return witnesses in past cases over the last two decades – including Ms. McShane - did not conduct adequately thorough and complete risk assessments for their clients. The UCA argued that it appears that utility witnesses made almost no references to risks arising from contributions in past rate cases, even when certain Alberta utilities had as much as 35 per cent of their distribution property as CIAC in the 1990s and early 2000s.[258]

Financial risk

378. With respect to the second argument (financial risk), the UCA stated that CIAC does not create any financial risk for shareholders and imposes no costs on them. Financial risk is therefore not a justification for imposing a management fee. Any financial risks or related shareholder costs associated with CIAC balances must have existed at essentially the existing or higher levels for many years, without the Utilities or the Commission ever pointing them out or recognizing them in rates.[259]

379. The UCA described the second argument as claiming that, because CIAC reduces the proportion of equity on which a return is earned relative to the total asset base, it leads to a lower equity ratio. Ms. McShane then analogized that reduction in equity as a proportion of the total asset base to the situation where a utility's financing of rate base includes debt, and the accepted principle that, when the debt ratio increases that increases financial risk, which in turn increases the cost of equity. The UCA submitted that Ms. McShane then characterized CIAC as debt-like and relied on the analogy with debt as the basis for her calculation of a proposed management fee. That calculation involves an after tax weighted average cost of capital (ATWACC) analysis in which she calculates a leverage adjustment that is supposed to reflect the increase in the cost of equity as the level of CIAC, and in her view the leverage or debt-like ratio increases, based on the premise that the ATWACC is constant.[260]

380. The UCA submitted that the difficulty with that argument is that CIAC does not resemble debt in any sense that is relevant to the concept of financial risk or the calculation of a leverage adjustment. The UCA further submitted that, with CIAC, there is no contractual interest obligation, and not even a principal repayment obligation. CIAC therefore creates no volatility in earnings and no financial risk, as that term is normally understood and explained in Appendix D to Ms. McShane's management fee evidence. It therefore does not increase the cost of equity for the firm, or impose any cost on shareholders.[261]

381. The UCA argued that, in her evidence, Ms. McShane provided no explanation of how CIAC increases the volatility of equity returns by creating financial risk, and that she provided no table or illustration analogous to her Table 2 to explain and demonstrate how CIAC creates financial risk that is distinct from the operational risk that Table 2 illustrates, for example using a hypothetical case where operating costs are constant.[262]

382. The UCA argued that the financial risk appears to be a risk that the Utilities have never noticed, even though they claim that they require an additional 40-100 basis points of equity return to compensate them for it, and that the lower equity ratio that Ms. McShane points to will arise, for example, through the accumulation of depreciation. Further, the UCA submitted that, if

[258] Exhibit 146.02, rebuttal evidence submitted on behalf of the UCA, paragraph 169.
[259] Exhibit 210.02, UCA argument, paragraph 244.
[260] Exhibit 210.02, UCA argument, paragraphs 271 and 272.
[261] Exhibit 210.02, UCA argument, paragraphs 273 and 276.
[262] Exhibit 210.02, UCA argument, paragraph 277.

the financial risk argument falls, the entire logical underpinning of Ms. McShane's calculation of her proposed management fee must fall as well, since it is premised entirely on that argument.[263]

Value of service

383. Lastly, the UCA argued that Ms. McShane's third argument is inconsistent with the legislation providing for cost-based ratemaking, the standard regulatory paradigm, and the fair return standard.[264]

384. The UCA stated that Ms. McShane's last argument is that it is not fair for the Utilities to be required to operate CIAC-financed facilities without earning a profit in connection with that activity, and that no rational competitive enterprise would operate expecting to recover only their expenses and earn a return on only a portion of the assets they use to provide services.[265]

385. As Mr. Marcus explained, the UCA argued, the argument that utilities are being deprived of a return is inconsistent with cost-based rate-making and the economic principles that underlie it. The entire theory on which the return on equity is set by regulatory agencies is that the required return on equity capital equals the (opportunity) cost of equity capital. As stated in Mr. Marcus' evidence:

> If the ROE equals the cost of equity, then it follows from elementary logic that investors should not care whether the utility invests the equity here, whether it invests the equity in a different project, or whether it passes money back to investors through dividends or share buybacks (or does not raise equity capital in the market) so the investors can invest capital elsewhere at a similar rate of return.[266] [footnotes omitted]

386. The UCA submitted that the evidence of Mr. Marcus explained why paying utilities a rate of return on capital that is never invested in the first place (through a management fee) provides skewed compensation for the utility. Mr Marcus stated in his evidence:

> Q. Please explain with reference to practical considerations why shareholders would be better off if they got an equity return on contributed property than if there were no contribution at all and shareholders simply invested equity in additional amounts of utility property?
>
> A. Giving the shareholders a rate of return when they do not have to make an investment is simply NOT equivalent to giving them a rate of return on an investment that they actually make.
>
> The Utilities' arguments focus on the asset side of the balance sheet (the contributed assets), but fail to recognize the liability side of the same balance sheet (that with contributed assets, they also require less debt and less shareholder equity).
>
> If the shareholders are paid a return as if they had invested equity in CIAC projects, but do not actually invest anything, they still have the money available for other valuable uses. Consider a project that a utility would have invested in, except it was required to collect CIAC instead. Two things happen:

[263] Exhibit 210.02, UCA argument, paragraphs 279 and 281.
[264] Exhibit 210.02, UCA argument, paragraph 245.
[265] Exhibit 210.02, UCA argument, paragraph 282.
[266] Exhibit 210.02, UCA argument, paragraph 285.

> 1. The utility does not receive a stream of earnings on the capital it would have invested in the new project. This is the sole focus of the Utilities' theory that equity investments are foregone when they invest in contributed property.
>
> 2. Because the utility has not invested its equity capital in projects paid for with CIAC, its equity capital is different than if it had invested in those resources in one or two ways:
>
>   a) If the utility would otherwise not have enough equity to invest in new resources treated as CIAC, it would have had to raise that equity in the capital markets. In this case, it avoids having to raise equity in the capital markets.
>   b) If the equity was available to it in the first place but not needed because of CIAC, the utility still has the equity available. The equity capital that is freed up because the investment was paid for using CIAC has a large number of other long-term uses ranging from buying back stock, paying more dividends, or making more investments (either regulated or unregulated).
>   c) The utility could invest in the longer term in additional projects (e.g., capital maintenance) if it had more equity available. In such a case, the equity not invested in contributions may simply be invested in different projects, not "lost" even under the Utilities' theory.
>
> To make decisions that consider the first factor (the asset side of the balance sheet) but do not consider differences in the availability of equity capital due to the CIAC (the liabilities and equity side of the same balance sheet) violates the principles of elementary finance, economics, and accounting and is, thus, extremely poor public policy. A decision to pay a full return on equity that is never invested in the first place, while still allowing the utility to invest the equity and earn a return (or alternatively never have to raise the capital at all) would give the shareholders far more money than if the utility had no contribution policy and simply invested the full amount in every project that was requested, regardless of cost. Therefore, paying shareholders an equity return without an equity investment clearly cannot be viewed as fair compensation, but is, instead, extremely skewed.[267]

387. With respect to the Utilities' fairness argument, the UCA submitted that Ms. McShane effectively acknowledged that her proposal is not consistent with the standard model of utility regulation, but said that it reflects a defect in the standard model, because the standard model does not fully reflect value in the way that competitive markets do.[268]

388. The UCA argued that this suggestion, in effect, is that there is something unfair or economically inappropriate with the concept of cost-based rate-making. The UCA cited Mr. Marcus' explanation that conventional utility regulation sets prices for utility service at a level that, in principle, allows the utility to recover exactly its costs, including the cost of equity capital or a fair return for shareholders. The UCA argued that there is nothing unfair or economically inappropriate about the model (cost-based rate-making) and that it is completely consistent with well-known economic principles.[269]

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267 Exhibit 81.04, prepared testimony of William B. Marcus, pages 48 and 49.
268 Exhibit 210.02, UCA argument, paragraph 289.
269 Exhibit 210.02, UCA argument, paragraph 290, 291, and 294.

389. In reply argument, the UCA noted that the Utilities had simplified the management fee issue by abandoning the first two arguments (operating leverage/risk and financial leverage/risk) and relying entirely on the fairness or value of service argument. The UCA further stated that the Utilities made it clear that the proposed management fee is separate from, and in addition to, any compensation due to shareholders in respect of amounts invested or risks borne by shareholders and that in the context of arguing that the management fee should not be treated as an offset to allowed ROE, the Utilities emphasized that it is intended to compensate the utility for something different from, and in addition to, the cost of equity capital.[270]

390. The UCA argued that the Utilities' position is that the management fee has nothing to do with ensuring that shareholders earn a fair return, or that shareholders are adequately compensated for the risks that they face, because all of that is already accomplished through the Commission's ROE and capital structure determinations. It therefore apparently has nothing to do with compensating shareholders for any incremental CIAC-related operating risks of the kind acknowledged by Mr. Marcus, or with any "phantom financial risk" that CIAC imposes on shareholders.[271]

391. The UCA further submitted that, in order to approve the management fee proposal, the Commission must repudiate not simply a regulatory "policy," but the entire economic and logical basis for the cost-based rate-making approach that it has applied for decades.

392. The UCA stated that one of the arguments advanced by the Utilities is that no rational business would enter into or operate facilities if it did not expect to earn a profit on that activity. The Utilities referred to a variant of that argument, where they discussed Mr. Marcus's evidence in relation to the discounting of services as analogous to operating facilities at no profit. While that exchange involved a side issue, the point was that the analogy with the supposed behaviour of competitive businesses is not correct because the issue is whether a firm earns an appropriate profit on its entire business, not on individual parts of the business. Mr. Marcus gave the example of brushing activity by utilities, where the utilities do not expect to "earn a profit" on brushing, but it is something they have to do in order to earn a fair return on their investment in the overall business. If the shareholders earn a fair return on their investment, which they will do under the cost-based rate-making model in the absence of a management fee, then regardless of how that investment is deployed they have no complaint and there is no unfairness.[272]

393. In response to the question of whether the Utilities should receive a fee for management of contributed assets, the CCA submitted that both operations and maintenance expense amounts awarded and the current Commission approved methodology for the determination of rate of return adequately compensates for the management of Utilities' operational assets, including those financed by customers through CIAC.

394. In reply argument, the CCA submitted that it disagreed with the Utilities' argument that customers are providing zero compensation for CIAC assets. The CCA considered that customers are responsible for 100 per cent of the ownership costs of the CIAC assets and customers are paying for the management of the assets in the form of revenue requirement items. These items include any management, including board of director fees and expenses, insurance, and engineering expenses. The CCA stated that the value of services provided by the utility in

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270 Exhibit 221.02, UCA reply argument, paragraphs 86, 90, and 91.
271 Exhibit 221.02, UCA reply argument, paragraph 92.
272 Exhibit 221.02, UCA reply argument, paragraph 104.

the management of CIAC assets are currently paid for by customers, and that by paying for assets up front in the form of CIAC customers are eliminating the risk to the utility holding the assets.[273]

395. The CCA also argued that the Utilities are compensated for invested capital, thus if there is no invested capital there should be no return. By having customers prepaying ownership costs in the form of CIAC, utilities should not be allowed to earn an excessive return. In particular, the CCA argued that a two per cent return is excessive, given the current interest rate and inflation rate environment. The two per cent equates to in excess of 50 per cent of current 30-year Government of Canada bond yields. The CCA argued that the Utilities are requesting 50 per cent of the risk free return and payment of all related operation and maintenance expenses, including management, engineering, insurance and board of director fees, for an asset they require customers to pay for up front.

396. The CCA submitted that a management fee should not be ruled on until Rider I effects are understood and could be forecast. The CCA argued that the Rider I will eliminate the need for a management fee, as CIAC levels will be reduced dramatically. The CCA also stated that it did not consider that a management fee should be implemented at the distribution level, noting that distribution utilities' CIAC levels are not comparable with transmission levels.

397. In responding to the question of whether the Utilities should be awarded a fee for management of contributed assets, IPCAA argued that there is no basis for a management fee of the nature applied for by the Utilities. Moreover, IPCAA submitted that adjustments to the ROE or the debt/equity ratio could only be justified if the management of property paid for by customers in some way increased utility risk, which, IPCAA argued, it does not.[274]

398. IPCAA reiterated the position set out in its evidence that with the AESO's proposed Rider I, there is no basis for a management fee, but stressed the fact that the Rider I proposal is not tied to the management fee proposal.

399. IPCAA noted that another concern with the proposed management fee is the potential double charging for DFO customers. If the TFOs are allowed to earn a management fee on TFO assets paid for by a customer contribution, IPCAA argued, then the DFO customers will be paying twice. First, they will pay a fee to the TFO for asset contributions from the DFO (that the DFO will pass through to its customers). Second, they will pay a return to the DFO for the AESO customer contribution in the DFO rate base for the TFO asset.[275]

400. CAPP argued that the management fee as proposed by Ms. McShane is unjustified and also excessive, and that CIAC should be treated as a deduction from rate base prior to calculating return and there should be no additional fee for management.[276]

401. In commenting on the justification for the award of a management fee, CAPP submitted that where the rate base is disappearing – the 'vanishing rate base' conundrum – there is an issue, as Mr. Marcus discussed, of providing the incentive to the company to continue to provide service and operate the system. Such situations are very rare and, CAPP submitted, the Utilities

[273] Exhibit 218.01, CCA reply argument, paragraphs 22, 23, and 24.
[274] Exhibit 212.01, IPCAA argument, paragraphs 23 and 24.
[275] Exhibit 212.01, IPCAA argument, paragraph 29.
[276] Exhibit 207.02, CAPP argument, paragraph 98.

requesting a management fee are instead in growth mode. CAPP argued that if utility investors had been harmed in taking CIAC all these years, the practice would never have developed and certainly would not have continued. CAPP submitted that, according to Ms. McShane, the Utilities have been undercompensated with returns that have been far too low on account of no allowance being made for the so-called "cost" to the utility investor from managing the assets bought with free money. If this were true, CAPP argued, one would expect to have seen some evidence of this in the marketplace. The Utilities should be selling at a discount because of this: yet they are not.[277]

402. The Utilities responded in reply argument to a number of the issues raised by interveners in response to the question of whether the Utilities should receive a management fee for contributed assets.

403. In response to the assertion that the Utilities are being fully compensated for the management of CIAC financed asset, the Utilities submitted that merely covering out of pocket costs is not compensation for the provision of value-added services.[278]

404. Noting that the principal basis for proposing the management fee was fairness, the Utilities submitted that while contributing factors such as increased operational risk and financial risk may appear minor in comparison, they are nevertheless valid. The Utilities noted that the UCA admitted the theoretically validity of the incremental operational risk and that attempts to trivialize those risks flatly ignore the $1.3-$2.5 billion of existing and forecast assets that the Utilities are now required to construct and operate on a wholly non-profit basis.[279]

405. The Utilities argued that the atypically high levels of CIAC in Alberta were not disputed by interveners. In response to intervener claims that the Utilities did not historically seem concerned about the size of CIAC or have not noticed the risk related to CIAC until recently, the Utilities stated that the issue was addressed in 2009 (ATCO Electric and AltaLink's GTA's) and that the electric distribution utilities have made concerted efforts to see changes made to investment policies.[280]

406. The Utilities stated that the UCA's purported analogies between CIAC and accumulated depreciation and vanishing rate base were misguided, and the Utilities also took exception to the fact that these positions were not advanced in evidence and could not be tested. Accordingly, the Utilities submitted that these positions should be accorded no weight by the Commission. In addressing these positions put forward by the UCA, the Utilities stated that the UCA's analogy between accumulated depreciation and CIAC is inapposite since no fee is sought to be recovered in respect of accumulated depreciation or amortized CIAC balances.

407. The vanishing rate base analogy, the Utilities submitted, fails to recognize that the FERC acknowledged that, in principle, compensation was due for valuable service rendered even where no investor-supplied capital was involved. While the FERC noted that the fee was wholly in lieu of a return on investor-supplied capital and not in addition to it, the Utilities submitted that it does not address the issue of CIAC, as the UCA acknowledged in Section 4.4 of their argument, wherein the UCA stated that it was not aware of any other jurisdiction that has approved a fee or

277 Exhibit 207.02, CAPP argument, paragraphs 107 and 111.
278 Exhibit 220.02, Utilities reply argument, paragraph 132.
279 Exhibit 220.02, Utilities reply argument, paragraph 133.
280 Exhibit 220.02, Utilities reply argument, paragraph 134.

other mechanism to compensate shareholders for the management of contributed assets.[281] The Utilities stated that where no rate base exists, the FERC approach may be appropriate and that, in this case, a substantial rate base composed of both investor and customer supplied capital does exist for which compensation is appropriate, though calculated differently for return on investor capital.[282]

408. The Utilities stated that the FERC cases, the RRO, water utilities and PPAs on depreciated power plants noted in the UCA's argument all support a management fee since they acknowledge that zero compensation for the value of services rendered does not result in just and reasonable rates.[283]

409. Noting that the UCA took issue with the analogy drawn between CIAC and debt, the Utilities argued that the accounting theory advanced by the UCA in its discussion appears to be new and untested evidence and should therefore be rejected by the Commission. Referring to specific sections of the UCA's argument, the Utilities argued that contrary to what the UCA stated in paragraph 275, interest is not the only thing which creates financial risk for shareholders; it ignores the principal repayment obligation. Further, contrary to paragraph 286, the Utilities are not solely focused on the asset side of the balance sheet. If there is an asset on the asset side, there must be something on the liability side. Since it is not equity, it must be a liability.

410. The Utilities stated that as a matter of principle, under IFRS, CIAC is accounted for as deferred revenue and therefore recorded as a liability on the balance sheet. The IFRS accounting entries are not driven by whether the regulator views the CIAC as debt or not. More importantly, debt rating agencies and other capital market participants do their analysis and form their opinions based on financial information prepared under IFRS. Title to the assets rests with the utilities and, under IFRS, are carried at cost without netting the related financing that is provided by customers. The Utilities argued that financing is not equity in the accounts of the utilities so it can only be debt. Under IFRS, the deferred revenue liability for CIAC is amortized or repaid over the lives of the CIAC assets.

411. For CIAC that is under Rider I, the utility would carry the assets at regulated NBV financed at the utility's approved capital structures. The Utilities argued that there is no physical difference and no difference in business risk between CIAC financed by customers and CIAC financed under Rider I.

412. Further, currently, if the AESO deems a CIAC funded asset to be part of the system, it can order the TFO to repay the customer contributed financing. The fact that the utility can be required to refund CIAC to customers when assets are deemed part of the system is confirmation, the Utilities argued, that the financing is repayable, like debt, on demand. In situations where repayment of CIAC occurs, the utility then finances the facilities with debt and equity. However, the nature of the services provided does not change; only the method of financing so, the Utilities argued, the compensation should not change either.

413. The Utilities also commented on the UCA's criticism of the management fee for being an alleged departure from cost-based, rate-base return methodology. The Utilities noted

[281] Exhibit 210.02, UCA argument, paragraph 299.
[282] Exhibit 220.02, Utilities reply argument, paragraph 135-136.
[283] Exhibit 220.02, Utilities reply argument, paragraph 137.

inconsistency between the UCA's position and its' own expert's view of the return margin mixed model. The Utilities argued that UCA's apparent treatment of a "return" as a non-cost item also appears to be contradicted by the proper characterization of "return" as an economic cost by Mr. Marcus, and that a management fee is no different in this respect; it is calculated on CIAC balances extant at regular intervals and thus is as fully cost-based as the regular calculation of a fair return is on investor-supplied capital.

6.2.4 How would the provision of a management fee impact risk generally, and specifically for each utility, in 2011 and 2012?

414. In argument, the Utilities stated that the management fee would have no impact on risk generally, or specifically for each utility in 2011 and 2012 and would have no impact on business risk as business risks are the same with and without the fee. The Utilities also stated that the management fee would have a *de minimus* impact on financial risk since the fee as proposed has a very minor positive impact on credit metrics.[284]

415. The UCA, the CCA and IPCAA all submitted that the provision of a management fee would reduce the Utilities level of risk.[285]

416. The UCA submitted that the risk profile of the distribution Utilities would be reduced by more than that of the transmission utilities because the distribution utilities have a higher percentage of contributed property. Mr. Marcus estimated that a distribution utility similar to ATCO Electric or Fortis would see an effective increase of about 105 basis points in ROE under Ms. McShane's proposal, while a transmission Utility like AltaLink or ATCO Electric would have an effective increase of 32-42 basis points in ROE, assuming that no customers take Rider I. The municipal distribution utilities, with their slightly lower level of contributions identified in Mr. Marcus' direct testimony, would be intermediate between these entities. Dr. Roberts suggested that the improvement in risk profile would be relatively small at 40 basis points but would be larger at 100 basis points.[286]

417. The CCA stated that, if any management fee is awarded, this must then be offset by reductions in operations and management expense and rates of return. Management, engineering and other O&M expenses for CIAC related assets are already included in the revenue requirement for the management of the utilities operational assets including those financed by customers through CIAC. Awarding of a management fee would simply provide for excess returns and cash flow to the utility thereby reducing risk.[287]

418. In reply, the Utilities argued that an award of an ROE is not risk reduction, it is risk compensation. The Utilities reiterated their position that business risk would not change and that financial risk impacts would be *de minimus*.[288]

[284] Exhibit 209.01, Utilities argument, paragraph 231 and 232.
[285] Exhibit 210.02, UCA argument, paragraph 298; Exhibit 211.01, CCA argument, paragraph 62; Exhibit 212.01, IPCAA argument, paragraph 31.
[286] Exhibit 210.02, UCA argument, paragraph 298.
[287] Exhibit 211.01, CCA argument, paragraph 62.
[288] Exhibit 220.02, Utilities reply argument, paragraph 144.

6.2.5 Have any other jurisdictions approved a fee or other mechanism to compensate shareholders for the management of contributed assets?

419. In the Utilities evidence, Ms. McShane made reference to a number of examples in which Alberta and other regulatory boards have adopted alternative approaches to compensation where the rate base/rate of return model did not provide adequate compensation. In argument, the Utilities stated that these examples were different but nevertheless support the notion that a utility is entitled to fair compensation for valuable services rendered.[289]

420. The UCA, the CCA and IPCAA all stated that they were not aware of any other jurisdiction that has approved a fee or other mechanism to compensate shareholders for the management of contributed assets.[290]

421. In its reply argument, the UCA noted the examples cited by the Utilities where regulators have awarded management fees or margin returns to regulated entities and thereby departed from the conventional cost-based rate-making construct. The UCA submitted that none of those examples is inconsistent with the UCA's position, in that all of them involve situations where a regulated entity finds itself with a rate base that is very small relative to its operating expenses, and where shareholders accordingly face operating risks that are large relative to their regulated earnings. The UCA argued that in those cases the margin return was awarded in place of a conventional rate base/rate of return profit, and not in addition to it.[291]

422. IPCAA stated that it was unaware of any evidence on the record suggesting that anything like the proposed management fee has been approved in any other jurisdiction and that a fee of the nature requested by the Utilities would appear to have no support from practices in other jurisdictions in Canada and the United States. However, IPCAA pointed out that numerous jurisdictions have adopted practices similar to the AESO's Rider I proposal and provided the examples of jurisdictions that have adopted Rider I-like approaches.

423. In its reply argument, IPCAA noted the references by the Utilities to cases where the rate base/rate of return model did not provide adequate compensation. These anecdotal references, IPCAA submitted, include Alberta-based examples such as the regulated rate tariffs of the distribution companies which are supported by special legislation. IPCAA argued that the Utilities, with the resources of eleven utility participants and an expert from Foster Associates Inc. could not produce a single example of an approved management fee for CIAC-financed assets.[292]

424. In response to IPCAA's argument, the Utilities stated that IPCAA's alleged Rider I "precedents" beg the issue that the management fee is trying to resolve and that Rider I was irrelevant to the management fee issue. The Utilities also argued that the very existence of those Rider I precedents is tacit recognition of the inherent unfairness to the Utilities for the not-for-profit turnkey construction and operation service they are obliged to provide. Finally, the Utilities noted that Rider I did not apply to gas utilities or electric distribution utilities.[293]

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[289] Exhibit 209.01, Utilities argument, paragraph 233.
[290] Exhibit 210.02, UCA argument, paragraph 299; Exhibit 203.01, CCA response to AUC Additional Questions, Q2; Exhibit 212.01, IPCAA argument, paragraph 32.
[291] Exhibit 221.02, UCA reply argument, paragraph 107.
[292] Exhibit 222.01, IPCAA reply argument, paragraph 21.
[293] Exhibit 220.02, Utilities reply argument, paragraphs 145-147.

6.2.6 If a management fee is awarded, who should pay the management fee?

425. The Utilities stated that the management fee should be recovered from the same customers who now pay for the operating and maintenance costs respecting CIAC funded assets. The Utilities noted that all operating costs for CIAC financed facilities are recovered from all existing customers without distinction amongst customer classes. Finally the Utilities stated that there is no need for consideration of this matter as part of a Phase II proceeding and the recovery of the fee as proposed is a straightforward matter and no further process should be directed with respect to allocations.[294]

426. The UCA and the CCA both submitted that no management fee on contributed assets was warranted. However, the UCA submitted, should a management fee be awarded, to the extent possible, any management fees adopted should be assigned directly to customers who make the contributions. The CCA shared the UCA's opinion on this issue.[295]

427. The UCA submitted that a fee on a TFO contribution assigned to the DFO (if allowed) should be paid by all DFO ratepayers, in the same proportion as the underlying DFO rate base for property contributed to the TFO. As a practical matter, however, the UCA argued that it is difficult to see how such a scheme could be feasible at the distributor level in relation to individual customers, especially small-volume customers. For distribution contributions, which are often for relatively small projects (such as underground line extensions to subdivisions), the UCA does not consider it practical to charge individual customers. The UCA argued that the amounts could be allocated to customer classes in Phase II cases in proportion to the allocation of contributions to customer classes that is made in order to calculate the appropriate allocation of return and taxes based on total rate base.[296]

428. The CCA stated that, if Rider I was approved and if, contrary to the CCA's recommendation, a management fee were approved, all distributors who are presently required to make contributions to the TFOs for TFO investments in distribution assets exceeding the AESO's maximum investment levels should be required to adopt Rider I. This will ensure there is no double counting; first, as a result of the distributor earning a return on the amount of the contribution and second as a result of the TFO earning a management fee on the same assets.[297]

429. IPCAA argued for resolution of the underlying problem that has caused the TFOs to pursue a management fee; namely, increased customer contributions by reason of, (a) the significant increases in TFO capital costs, and (b), the lagging of the AESO's investment levels. IPCAA submitted that implementation of Rider I will contribute to resolving this underlying problem.[298] IPCAA further submitted that, should the Commission choose to approve a management fee, the determination of which customers should pay a fee of the nature of the management fee proposed by the Utilities is a Phase II general tariff application matter and should not be determined in this proceeding.[299]

294 Exhibit 209.01, Utilities argument, paragraph 236, 237 and 239.
295 Exhibit 210.02, UCA argument, paragraph 302; Exhibit 203.01, CCA response to AUC Additional Questions, Q3.
296 Exhibit 210.02, UCA argument, paragraphs 302 and 303.
297 Exhibit 203.01, CCA response to AUC Additional Questions, Q3.
298 Exhibit 212.01, IPCAA argument, paragraph 33.
299 Exhibit 212.01, IPCAA argument, paragraph 34.

430. IPCAA also noted that the Commission's question; namely, "should *only specific* rate payers pay the management fee on the assumption that the party who causes a cost to be incurred or who benefits from the cost incurred should pay" helps to highlight the absurdity of the Utilities' management fee proposal. If one were to point an accusing finger at the group of customers it might be claimed "caused" the so-called "need" for a management fee, the one group that might be singled out is the group of customers paying for the customer contributed assets. But how exactly could it be claimed that these customers caused this cost? They have already done everything and more that could reasonably be demanded of any customer – in this case, of course, paying the full costs of the facilities. Moreover, IPCAA argued, the amount of the cost is not something these customers necessarily have any control over.[300]

431. IPCAA submitted in reply argument that the Utilities apparently seek a decision that would prospectively deny basic intervener rights in Phase II proceedings to challenge matters such as cost causation and cost allocations. While debating the allocation of the management fee in Phase II proceedings will be an administrative burden, denying the right to be heard on this issue is not appropriate. A better solution is to deny the management fee for the reasons stated earlier in IPCAA's argument and reply.[301]

432. In reply argument, the Utilities stated that the fact that regulators have directed that the O&M relating to the operation of CIAC-funded assets should be recovered from all system users fully supports the position advanced by the Utilities in argument.[302]

6.2.7 What is the minimum amount of contributions in aid of construction that should warrant a management fee?

433. In argument, the Utilities stated that, while the proposed management fee could be applied to all contributions, their recommendation was to limit the application of the 2 per cent return to CIAC balances in excess of 4 per cent gross approved rate base (inclusive of contributions) in order to appropriately recognize the fact that other utilities in Canada also have some CIAC, albeit generally in smaller proportions.[303]

434. The UCA and the CCA did not believe that any amount or level of CIAC should warrant a management fee.[304]

435. IPCAA re-affirmed its previous submissions that the proposed management fee cannot be awarded under the *Electric Utilities Act*. IPCAA stated that should the Commission consider that it has the jurisdiction to award a fee of the nature proposed by the Utilities and that such a fee should be awarded, IPCAA recommends that the Commission use a bright line test of 10 per cent for determining if a management fee is required for the TFOs, as has been previously suggested by AltaLink Management Ltd. The bright line should be calculated by dividing the unrecovered CIAC by the total rate base of each utility.[305] IPCAA submitted that it did not agree with the Utilities four per cent bright line test for the following reasons:

[300] Exhibit 212.01, IPCAA argument, paragraph 37.
[301] Exhibit 222.01, IPCAA reply argument, paragraph 28.
[302] Exhibit 220.02, Utilities reply argument, paragraph 148.
[303] Exhibit 209.01, Utilities argument, paragraph 240.
[304] Exhibit 210.02, UCA argument, paragraph 304, Exhibit 211.01, CCA argument, paragraph 65.
[305] Exhibit 212.01, IPCAA argument, paragraphs 41 and 42.

a) A 4% bright line test contradicts the evidence of AltaLink's own witness from a prior proceeding that stated that going beyond a 10% bright line was not going to be within "a likely reasonable range", implying that less than 10% was within a likely reasonable range.

b) Even noting that the Utilities Table 1 includes a very short list of allegedly comparable utilities, the proposed 4% bright line test is well below that of FortisBC (8.8%) and Terasen Gas (6.3%) and somewhat below Maritime Electric (4.5%). A bright line used to justify an exceptionally unusual payment such as a management fee should be a boundary condition, not a median or some type of average. Clearly, FortisBC, Terasen and Maritime Electric do not receive a management fee and therefore the Utilities have a very weak argument for any harm at a bright line test below 10%.

c) The average historical CIAC as a percentage of gross rate base for the Utilities for the period 2007 to 2010 has been 8.5%. This level is still below the FortisBC level of 8.8%, further suggesting that nothing below 10% should be seen as an appropriate "bright line" for the determination of a management fee.[306] [footnotes omitted]

436. In reply argument, the Utilities submitted that the 10 per cent cut off proposed by IPCAA received no attention at the hearing and no weight should be given to IPCAA's argument in that regard. Further, the Utilities stated that, in suggesting that Dr. Cicchetti called for a 10 per cent threshold, IPCAA has seriously mischaracterized that evidence. The Utilities also stated that the current management fee proposal is made on the basis of Ms. McShane's evidence and not evidence filed in another proceeding.[307]

6.2.8 What method or formula should the Commission adopt to calculate a management fee if it chooses to award one?

437. The Utilities acknowledged that while there are likely a number of approaches that could be used to estimate a level of compensation for CIAC that would simultaneously recognize the value of services provided and the risks assumed by the Utilities, the approach advanced by Ms. McShane is the best option available. The Utilities noted that no other proposals were filed in evidence nor otherwise detailed and examined on the record of this proceeding.[308]

438. The Utilities stated that the selected methodology met Ms. McShane's objectives of constructing an approach: (1) that had a basis in financial theory, (2) the outcome of which could be objectively determined, (3) which could be applied consistently across all the Alberta Utilities, and (4) that was supported by regulatory precedent.[309]

439. The Utilities submitted that Ms. McShane presented what are really two approaches which proceed from different premises but yield the same quantum of compensation. The first proceeds on the premise that CIAC represents a liability akin to debt, which decreases the effective equity ratio of the Utilities. In the absence of CIAC, the assets would be financed with interest bearing debt. The amount of compensation that is reasonable for CIAC funded assets is derived from the increase in the cost of equity that results from the reduction in the Utilities'

[306] Exhibit 212.01, IPCAA argument, paragraph 46.
[307] Exhibit 220.02, Utilities reply argument, paragraph 150, 151.
[308] Exhibit 209.01, Utilities argument, paragraph 244.
[309] Exhibit 209.01, Utilities argument, paragraph 245.

effective equity ratio due to the presence of debt-like CIAC. The amount of CIAC compensation is equivalent to the return required for bearing incremental financial risk.

440. The Utilities noted that Ms. McShane explained that the same estimate of a reasonable margin is arrived at without invoking financial risk by applying the "OEB Methodology" under which it is assumed that, in the absence of CIAC, the utilities financed all of their assets at the same overall return (their opportunity cost of capital). To recognize that ratepayers are providing an interest-free loan to the Utilities, ratepayers are credited with the utility market cost of debt. The effective compensation to the utilities for CIAC is limited to the difference between their overall cost of capital and their cost of debt.[310]

441. While alternatives such as a return margin were considered by Ms. McShane, the Utilities submitted that the selected methodology was chosen because it could be easily applied generically across utilities and it appropriately focused on the assets and resulted in a sharing of benefits of the CIAC among customers and utilities.[311]

442. In response to Mr. Marcus' criticism of the quantum of the proposed management fee[312] as disproportionate to the impact on operating leverage and additional risk posed by CIAC, the Utilities stated that examining the impact on operating leverage alone does not suffice. It is not a benchmark for reasonableness or fairness of the proposed fee. The Utilities noted that the Utilities are exposed to operational, regulatory and market risks with respect to CIAC financed assets and that these risks are not easily quantifiable.

443. Further, the Utilities submitted that the proper context for the evaluation of the reasonableness of a management fee is not solely the risks borne with respect to the CIAC-funded assets, but also fairness in light of the value of service provided.

444. In response to parties'[313] submissions that a small percentage addition to O&M expense could be employed as a management fee, the Utilities stated that such an approach should be rejected and that any suggestion that what is being managed for contributed property is limited to operating and maintenance expense misrepresents and marginalizes the functions that the Utilities perform in relation to CIAC-financed assets.[314]

445. The UCA opposed the imposition of a management fee in any form and had no opinion on what formula should be applied or collection method adopted.[315]

446. The CCA submitted that, while it did not support any management fee on contributed assets, the concept put forward by the Utilities is that it is required to compensate the utility for planning, managing and operating the contributed assets. Accordingly, the management fee, if approved, should be determined as a per cent of the O&M expenses associated with contributed assets. The CCA further submitted that the determination as to whether a management fee

310 Exhibit 209.01, Utilities argument paragraph 246.
311 Exhibit 209.01, Utilities argument, paragraph 248.
312 Transcript, Volume 6, page 815, lines 15-23.
313 Exhibit 130.01, Mr. Marcus' response to Utilities-UCA-58(c)), Exhibit 202.01, IPCAA response to AUC Additional Questions, Q4; Exhibit 203.01, CCA response to AUC Additional Questions, Q4.
314 Exhibit 209.01, Utilities argument, paragraph 254.
315 Exhibit 210.02, UCA argument, paragraph 305.

applies or not should be made at the time of the GRA, on a forecast basis, having regard to a threshold.[316]

447. IPCAA stated that, if a management fee were to be approved, any fee should only be calculated on any amounts that exceed the 10 per cent bright line test. Furthermore, it should be calculated on the basis of the service of managing property and should not be based on the value of the property itself.[317] IPCAA further stated that the idea that the Utilities are providing the service of managing the CIAC assets without compensation is wrong. Any cost incurred is compensable and is compensated for as is any reasonable and prudent cost.[318]

6.2.9 Should other forms of no-cost capital also be eligible for a management fee? What is the rationale for including or excluding other forms of no-cost capital?

448. The Utilities submitted that the management fee proposal was to apply only to CIAC and that other forms of no-cost capital would not be eligible for, or included in, the calculation of the management fee. The Utilities noted that there is a distinction to be made between CIAC and other forms of no cost capital. CIAC balances, the Utilities argued, relate to long-term assets over which the Utilities provide valuable services and bear risks. Other forms of no cost capital arise as a result of timing differences between the incurrence and recovery of costs and do not involve the fairness issue related to CIAC financed assets and, consequently, do not warrant treatment analogous to that requested for CIAC.[319]

449. In reply argument, the Utilities added that the management fee was based in part on the business risks inherent in offering a not-for-profit turnkey construction service and not-for-profit operations and maintenance service and that these services were very different from the business risks associated with managing deferred taxes and depreciation reserves.[320]

450. The UCA submitted that it did not accept the premise that a management fee is appropriate or necessary as compensation related to the management of CIAC or any other form of no-cost capital, or accumulated depreciation. Any proposal to give shareholders a return on amounts that they have not actually invested in the business is misconceived and inconsistent with the principles of cost-based rate-making.[321]

451. The CCA considered that no management fee should be allowed on no-cost capital. The CCA considered that the fair return and revenue requirement awards have, and do, take into account issues surrounding no-cost capital. Customers currently pay all costs associated with no-cost capital including asset management. The CCA views no-cost capital as reducing utility risk, not increasing risk.[322]

[316] Exhibit 203, AUC-CCA-04.
[317] Exhibit 212.01, IPCAA argument, paragraph 47.
[318] Exhibit 212.01, IPCAA argument, paragraph 49.
[319] Exhibit 209.01, Utilities argument, paragraphs 257 and 258.
[320] Exhibit 220.02, Utilities reply argument, paragraph 156.
[321] Exhibit 210.02, UCA argument, paragraph 306.
[322] Exhibit 211.01, CCA argument, paragraph 67.

452. IPCAA submitted that, as it had previously discussed, the Commission does not have the power to award compensation for costs for which no utility investment has been made over and above what is needed to reimburse the utility for its reasonably incurred costs.[323]

6.2.10 Assuming that the balance of CIAC changes on an annual basis, what method or formula should the Commission adopt to calculate a management fee and include the fee in base rates, it if chooses to award one? When should a management fee be instituted if it is approved?

453. The Utilities summarized the calculation of the annual management fee in their argument, as follows:

> The annual Management Fee should be calculated by (1) summing the mid-year approved CIAC balance and rate base net of other forms of no cost capital (i.e. mid-year pro-rated invested capital); (2) calculating 4% of the total; and (3) subtracting the 4% from the forecast test-year CIAC balance. The resulting balance equals the CIAC eligible for Management Fee. The management Fee in dollars for each of the Alberta Utilites would then be calculated by applying the requested 2% to the eligible CIAC balance. For the taxable utilities, the resulting Management Fee would then be grossed up by the test year corporate income tax rate.[324]

454. The Utilities noted that, if the Commission approves Rider I, the annual amount of CIAC eligible for the management fee would be dependent on the extent to which customers opt for Rider I, which is uncertain. Consequently, the Utilities recommended the implementation of a deferral account for the TFOs which would true up the difference between the actual and forecast management fee.[325]

455. For those utilities who are, or will be, subject to PBR, the Utilities recommended the calculation of the annual management fee described above be modified to use the previous year actual mid-year balances as, for other than the PBR base year, there may not be an approved forecast mid-year rate base balance.[326] The Utilities submitted that the management fee should be approved to be effective January 1, 2011.[327]

456. The UCA's position was that no management fee is warranted, and so it did not offer an opinion on how the Commission should calculate a fee that the UCA does not believe should be imposed in any form or in any amount.[328]

323 Exhibit 212.01, IPCAA argument, paragraph 54.
324 Exhibit 209.01, Utilities argument, paragraph 260.
325 Exhibit 209.01, Utilities argument, paragraph 261.
326 Exhibit 209.01, Utilities argument, paragraphs 262 and 263.
327 Exhibit 209.01, Utilities argument, paragraph 264.
328 Exhibit 210.02, UCA argument, paragraph 309.

457. IPCAA submitted that, should the Commission approve a management fee against IPCAA's recommendations, IPCAA submits that the management fee should be:

a) Calculated only on any amounts that exceed the 10% bright line test; and

b) Calculated on the basis of the service of managing property and should not be based on the value of the property itself.[329]

458. In reply argument, IPCAA reiterated its submission that the Commission is without jurisdiction under the *Electric Utilities Act* to award a management fee as requested by the Utilities. Further, IPCAA submitted that, should the Commission conclude that it does have jurisdiction to award some form of fee for management services as requested by the Utilities, and that such a fee is warranted, IPCAA submits that it should only be instituted after completion of a Phase II proceeding of the AESO or relevant DFO.[330]

459. In its reply argument, the Utilities stated that it would be grossly unfair to the Utilities to deny the recovery of the management fee now because the uptake on Rider I may not be known for some months after a decision is released.[331]

6.3 Commission findings

Jurisdiction to award a management fee

460. The Commission has the obligation to ensure that the rates it establishes are just and reasonable in accordance with Section 121(2)(a) of the *Electric Utilities Act*, Section 36(a) of the *Gas Utilities Act* and Section 89(a) of the *Public Utilities Act*.

461. In fixing just and reasonable rates, the *Gas Utilities Act* (Section 37) and the *Public Utilities Act* (Section 90) require that the Commission determine a rate base on which to fix a fair return by giving due consideration to the cost of the property when first devoted to public use and to the prudent acquisition cost to the owner of the utility, and to necessary working capital. In the *Electric Utilities Act,* return is considered to be a subset of the "costs and expenses associated with capital *related to the owner's investment in the electric utility*" (Section 122(1)(a)) and is specified as a fair return on the equity of shareholders of the electric utility as it relates to the investment (Section 122(1)(a)(iv)).

462. The process by which the Commission sets rates was described by the Supreme Court in *Northwestern Utilities Ltd. v. City of Edmonton*[332] and cited in *Stores Block*:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. **In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also**

[329] Exhibit 212.01, IPCAA argument, paragraph 55.
[330] Exhibit 222.01, IPCAA reply argument, paragraph 34.
[331] Exhibit 220.02, Utilities reply argument, paragraph 158.
[332] *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684 at page 691; *Stores Block, supra,* paragraph 65.

> **determined in Phase I.** The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered. [emphasis added]

463. This approach to approving the recovery of a utility's prudent costs and awarding a fair return on the equity portion of a utility's investment is the basis of the cost of service regulation framework that has been employed by the Commission for decades.

464. The legislature has recognized that there are situations where return on rate base may be inadequate to allow for proper compensation. Section 6(1)(b)(i) of the *Regulated Rate Option Regulation*[333] promulgated under the *Electric Utilities Act* requires the Commission to approve a reasonable return (which is not tied to investment but rather to the obligation to provide service) as well as a risk margin (Section 5) that compensates for a number of specific risks.[334] Neither the *Electric Utilities Act* nor the *Gas Utilities Act* contain such provisions.

465. Interveners generally argued that the relevant legislation and cost of service regulation principles provide for the entire compensation scheme for the Utilities, which consists only of a return on the capital invested in rate base and the recovery of prudent costs. The interveners characterized the management fee as a request for additional return or profit, which they argued the Commission was not authorized to grant under a strict interpretation of the statutes together with traditional cost of service regulatory principles.

466. In general, the Commission agrees with this interpretation of the statutes. However, the Commission considers there are circumstances, such as the "vanishing rate base" scenario cited by some interveners, where the return on rate base approach may not allow for sufficient return to provide for just and reasonable rates. In such situations, the Commission considers that case law provides it with the authority to implement a mechanism, which might be in the form of a management fee, in order to ensure that just and reasonable rates are achieved.

467. As noted above, the Utilities cited the Supreme Court of Canada's decision in *Northwestern 1961* in support of their *quantum meruit* argument. In that case, the Supreme Court of Canada found that the Commission's predecessor had jurisdiction to fix just and reasonable rates, which included fixing rates to allow for transitional losses between the date of application and the date of decision. The Court concluded that, even in the absence of any statutory provision, there is an obligation at common law for ratepayers to pay for utility service on the basis of *quantum meruit* as part of the jurisdiction to ensure that tolls are at all times just and reasonable.

468. In *Northwestern 1961*, the authority of the Commission's predecessor to establish a "purchased gas adjustment clause" was at issue. This clause was essentially a variance account mechanism that permitted the utility to recover from consumers in the future amounts the utility had to pay for gas that proved more expensive than the utility's estimates (and to refund amounts

[333] AR 262/2005.

[334] Similarly, Section 5(a) of the *Default Gas Supply Regulation*, AR 184/2003 under the *Gas Utilities Act* provides for "…a reasonable return on costs deemed eligible by the Commission, excluding the cost of gas that is provided and delivered…"

to consumers if the estimates proved to be greater than the actual cost). While not specifically provided for in the relevant statutes, the jurisdiction of the Commission's predecessor to approve such a mechanism was upheld by the Court. In particular, at pages 406-407 of its judgment, the Court stated that the authority flowed from the power to set just and reasonable rates which would yield a fair return:

> With great respect, however, the proposed order would be made in an attempt to ensure that the utility should from year to year be enabled to realize, as nearly as may be, the fair return mentioned in that subsection and to comply with the Board's duty to permit this to be done. How this should be accomplished, when the prospective outlay for gas purchases was impossible to determine in advance with reasonable certainty, was an administrative matter for the Board to determine, in my opinion. This, it would appear, it proposed to do in a practical manner which would, in its judgment, be fair alike to the utility and the consumer.
>
> As pointed out by Porter J.A., s. 67(5) does not touch the matter and this the respondent concedes, but the Board has not assumed to act under that subsection. Rather **did it propose to make the order under the powers given to it and the duty imposed upon it by the sections to which I have referred to fix just and reasonable rates which would yield the fair return mentioned in s. 67(2).** [emphasis added]

469. The Commission considers that this case supports the proposition that, in certain circumstances, in order to satisfy its duty to set just and reasonable rates, the Commission has the jurisdiction to approve compensatory schemes that are not specifically provided for in the statutes to ensure that a fair return is realized.

470. The Commission will now consider the questions as to whether: (1) the rate of return compensation scheme set out in the legislation is insufficient to provide for just and reasonable rates given the current levels of CIAC, and (2) if so, whether the proposed management fee is warranted.

471. It should be noted that this was not the manner in which the Utilities framed their argument in support of the management fee. The Utilities' primary argument was that the principle of *quantum meruit* requires that the services that the Utilities are providing with respect to the CIAC-financed assets be compensated. The Utilities also justified the management fee by submitted evidence related to increased risk (financial, operating leverage and business risk).

472. Therefore, with respect to the first question, the Commission will consider whether the arguments of the Utilities with respect to *quantum meruit* and increased risk associated with CIAC support the conclusion that the rate of return compensation scheme is insufficient.

Is the rate of return compensation scheme set out in the legislation insufficient to provide for just and reasonable rates?

473. As discussed above, the *Electric Utilities Act* and the *Gas Utilities Act* provide for compensation consisting of a return on utility investment and recovery of prudent costs. The Utilities submitted that where CIAC levels approximate the industry average, the conventional model generally provides fair and reasonable compensation. However, the Utilities argued that CIAC levels are significantly higher in Alberta than the industry average and, as a result, "that paradigm does not provide fair or any compensation in relation to services provided and risks

borne in relation to CIAC-funded assets."[335] The Utilities stated that the proposed management fee will augment the conventional model, and also stated that the proposed management fee provides for a margin or fair compensation for all of the services they render relating to assets that are constructed, owned and operated by the Utilities, but which are financed by customers.

474. Interveners argued that the statutory and regulatory schemes do provide for sufficient compensation. The UCA submitted that the cost-based rate-making principle says that utilities should be entitled to charge rates that provide them with a reasonable opportunity to recover their prudently incurred costs, including a fair return on the capital they have invested in the business, but that they are not entitled to charge rates that are higher than that. The UCA argued that approval of the management fee proposal would result in profits or returns to shareholders that exceed the cost of equity capital and the levels dictated by the fair return standard, and it would result in rates that are not just and reasonable.[336]

475. In determining whether rates are not just and reasonable without specific compensation for services the Utilities provide in respect of the CIAC-funded assets, given the current levels of CIAC, the Commission will now address the main arguments cited by the Utilities namely:

- *quantum meruit* for value of services rendered
- risk considerations

Value-added services and the concept of *quantum meruit*

476. The Utilities submitted that the services for which they are requesting compensation by way of a management fee include the construction, operation and maintenance of CIAC funded assets. While the interveners argued that the Utilities are being fully compensated for the provision of services, the Utilities replied that merely covering out-of-pocket costs is not compensation for the provision of value-added services.[337]

477. The Utilities appear to suggest that the concept of *quantum meruit* provides both the jurisdiction and the requirement that they be compensated above cost for these services, which they have also referred to as the "value-added" services. Thus, the Commission considers that determining the value of the services provided by the Utilities in respect of the CIAC-funded assets is fundamental to assessing the Utilities' *quantum meruit* argument.

478. The Commission finds that the Utilities have not established that they are providing any "value-added" services specifically associated with CIAC-funded assets. The Utilities argued that the construction, operation and maintenance of CIAC-funded assets is a value added service. The Commission does not agree. The construction, operation and maintenance of the assets owned by the utility are necessary for the provision of electric utility service, whether the assets were funded by CIAC or not. The Utilities have proffered no evidence of having to provide any services beyond the delivery of the electric utility service that is required, pursuant to their obligation to serve, and for which they are compensated through the rates approved by the Commission.

[335] Exhibit 220.02, Utilities reply argument, paragraph 111.
[336] Exhibit 221.02, UCA reply argument, paragraph 100.
[337] Exhibit 220.02, Utilities reply argument, paragraph 132.

479. Further, the Commission considers that the Utilities have not provided any evidence by which the Commission can quantify these "value-added" services, over and above the costs incurred for the provision of electric utility service, for which they are compensated through the rates approved by the Commission.

480. The Utilities cited *Northwestern 1961* in support of the *quantum meruit* nature of their claim. However, the Commission finds that the Utilities are unable to specifically quantify the actual cost of the "value added" services, other than to say that reasonable compensation can be derived from "the increase in the cost of equity that results from the reduction in the utilities' effective equity ratio due to the presence of debt-like CIAC."[338] In contrast, in *Northwestern 1961*, the transitional amounts that the Commission's predecessor determined the utility should be compensated for were clearly identifiable and quantifiable amounts incurred by the utility. This is in distinct contrast to the Utilities' request for compensation.

481. Nonetheless, the Utilities' proposal that the management fee should be equivalent to the increase in the cost of equity that results from the reduction in the Utilities' effective equity ratio due to the presence of debt-like CIAC appears to argue that the Utilities incur an opportunity cost by being required to construct, operate and maintain CIAC funded assets. However, the Utilities recover the prudently incurred costs to construct, operate and maintain the CIAC funded assets as well as an allowed return on the working capital required to fund these costs through the rates approved by the Commission. Consequently, the Commission does not agree that the Utilities incur an opportunity cost in being required to fund the construction, operation and maintenance of the CIAC funded assets.

482. On a final note, when one looks at the contributed capital scheme and the notion that customers must contribute some portion of the initial start up costs, one must also consider what benefit the utility receives. If it was not for the customer's contribution, the utility would not have that customer nor the opportunity to invest in the rate base assets not funded by CIAC that are required to provide service to that customer.

483. The Commission finds that it has not been established that the services provided by the Utilities in respect of CIAC-funded assets represent a value added service that is in addition to the utility services which are compensated under the statutory scheme. Nor has it been established that the services have any quantifiable value. Accordingly, the Commission finds that there is no evidence that the provision of services in respect of CIAC-funded assets requires any compensation through a management fee or results in rates that are not just and reasonable.

Risk considerations

484. The Commission will now address the question of whether the Utilities rates are just and reasonable considering the argument that the Utilities incur risks related to CIAC for which they are not adequately compensated.

485. The Utilities argued that (1) the higher the level of CIAC relative to the total rate base, the higher is the operating leverage; and (2) the higher the level of CIAC relative to total capital (inclusive of CIAC), the higher is the financial risk.[339] The Utilities stated that operating leverage

[338] Exhibit 86.01, opinion on management fee and Rider I, lines 48-51.
[339] Exhibit 86.01, page 13, lines 361-364.

refers to the sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs.[340]

486. The Utilities also stated that, as set out in CCA-Utilities-31, there are business risks and liabilities other than the operating leverage risk to which the Utilities are exposed. The Utilities listed these business risks as:[341]

- Operational risk (liabilities for):
  - i. Damages to company facilities by others or weather
  - ii. Public injury as a direct result of company operations
  - iii. Environmental contamination resulting from a release of contaminates
  - iv. Release of natural gas causing fire or explosion as a direct result of company operations
  - v. Service outages which result in customer property damages and/or injury as a result of equipment failure
  - vi. Decommissioning and asset retirement liabilities
- Regulatory risk:
  - i. unfavorable regulatory decisions
  - ii. compliance with regulation and legislation
  - iii. unforeseen changes to provincial or federal legislation affecting the company operations
- Other business risks:
  - i. Forecasting operating and maintenance costs
  - ii. Franchise loss
  - iii. Weather
  - iv. Market loss
  - v. Fraud

487. In her evidence Ms. McShane stated that the presence of CIAC increases the effective debt ratio (or alternatively, decreases the effective equity ratio) and that CIAC represents a liability that is akin to debt, albeit interest-free.[342] Further, Ms.McShane stated that the lower the equity ratio, the higher the financial risk, and the higher the cost of equity for a given level of business risk.

488. The Utilities stated that the higher level of CIAC relative to total rate base, the higher is the operating leverage, or sensitivity of the earned return on rate base to unanticipated changes in revenues and/or costs. Ms. McShane provided an example in Table 2 of her evidence of the sensitivity of the ROE to an unanticipated change in O&M expense. Ms. McShane stated that the example showed that an unanticipated increase in O&M expense reduced the actual ROE below the allowed ROE by a wider margin for a utility with CIAC than it does for a utility with no CIAC and stated that greater CIAC introduces greater potential volatility in actual earnings.

489. Mr. Marcus submitted that in principle, the argument that CIAC creates operating leverage that results in increased operating risk and an increase in the cost of equity for shareholders has some theoretical validity since CIAC can create incremental operational risk. The Commission agrees with this observation, as further discussed below.

[340] Exhibit 86.01, page 13, lines 364-366.
[341] Exhibit 135.02, CCA-Utilities-31.
[342] Exhibit 86.01, page 14, lines 381-383.

490. The Commission notes Ms. McShane's rebuttal evidence in which she acknowledges that the proposed management fee exceeds the likely deviation from the allowed return due to higher operating leverage, and includes compensation for other risks as well as the value of services provided.[343] Given the Commission's determination that there are no value added services provided by the Utilities with respect to the CIAC-funded assets, the Commission does not agree that the incremental level of business and financial risk associated with these assets, on its own, supports the management fee proposed by the Utilities.

Management fee conclusions

491. The Commission determined above that the services related to CIAC-funded assets are not distinct from the utility services compensated for under the statutory scheme and that the incremental level of risk associated with these assets, on its own, does not support the management fee proposed by the Utilities. Consequently, the Commission does not accept the management fee proposal.

492. Additionally, the Commission considers that the concept of a management fee should be viewed in the context of the Alberta regulatory framework. For example, IPCAA noted the potential "double charging" for DFO customers that may occur if the TFOs are allowed to earn a management fee on assets paid for by a customer contribution. In this case, DFO customers would pay the management fee to the TFO (that the DFO would pass on to its customers), as well as the return to the DFO for the contribution made to the TFO, because the contribution would become part of the DFO's rate base.[344]

493. This is of particular concern in situations in the electric utility industry where the TFO and DFO are part of the same larger corporate entity. For ENMAX, EDTI and ATCO Electric TFOs, the corporate shareholder earns a rate of return on CIAC assets where the CIAC funding comes from the DFO affiliate, and the TFO affiliate would earn a management fee on those same assets. In her evidence, Ms. McShane expressed her view that corporate affiliations should not be a determinant of the appropriate compensation for CIAC and that compensation for CIAC should be provided to the regulated entity that constructs, owns, operates and manages the underlying assets and provides the related services.[345]

494. The Commission does not agree with the position advanced by Ms. McShane and the Utilities in this instance. The Commission considers that, for the corporate shareholder to receive a return on transmission assets funded by the DFO, because the contribution is added to the DFO's rate base, as well as a management fee provided to the TFO on those same transmission assets, would result in an unwarranted additional return to the corporate shareholder.

495. Nonetheless, even though the management fee proposed by the Utilities is not warranted, the Commission agrees with the Utilities that CIAC-funded assets contribute to business risk. In general, business risk would be expected to rise in proportion to assets. The Commission agrees with the Utilities that, without an increase in equity, CIAC-funded assets would cause an increase in financial risk and operating leverage risk.

343 Exhibit 152.04, McShane rebuttal evidence on management fee, lines 378-385.
344 Exhibit 212.01, IPCAA argument, paragraph 29.
345 Exhibit 86.01, page 14, lines 381-383.

496. As outlined in Section 5 above, it has been the practice of the Commission and its predecessor to adjust for any differences in risk among the utilities by adjusting their individual equity ratios. The Commission has reaffirmed its adherence to this approach in this decision.

497. In this regard, the Commission notes that the equity ratios awarded in Decision 2009-216 were determined by examining the credit metrics for a sample of utilities with an A credit rating. The sample utilities used in Table 12 of Decision 2009-216 were exclusively Alberta utilities and therefore reflected the typical level of contributed assets of the Alberta utilities, as of 2009. These Alberta utilities were able to achieve A credit ratings at their observed credit metrics despite having a certain amount of CIAC-funded assets.

498. Furthermore, in the case of AltaGas, the EUB explicitly recognized in Decision 2004-052 that a high level of customer contributions increases business risk, when it set the equity ratio of AltaGas in the 2004 GCOC proceeding. In that decision, the EUB stated:

> The Board considers that AltaGas has greater business risk than the typical gas distribution company.
> AltaGas and ATCO Gas considered the business risks of AltaGas to be higher than the business risks of ATCO Gas, due to AltaGas' relatively small size, rural service area, geographically dispersed customers and high level of customer contributions.
> […]
> Considering all of the above, the Board concludes an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.[346]

499. As the UCA pointed out in its argument, no utilities have been downgraded since the 2009 proceeding and, therefore, the Commission considers that the equity ratios awarded in Decision 2009-216 adequately reflected all of the Alberta utilities' business risks, including any risks associated with the CIAC-funded assets.

500. In this decision, the Commission continued the equity ratios awarded in 2009 for 2011 and 2012, with the exception of ATCO Electric TFO, AltaLink TFO, and ATCO Pipelines. Based on the data provided in Attachment A of Ms. McShane's evidence, CIAC as a percentage of gross rate base (inclusive of contributions) of the Alberta Utilities, in total, is expected to decrease from 17 per cent in 2009 to 15 per cent 2012.[347]

501. Specifically, the data provided in Attachment A of Ms. McShane's evidence shows that, while the level of CIAC for electricity and gas distributors is forecast to decrease from 21 per cent of gross rate base in 2009 to 18 per cent in 2012, the CIAC for TFOs is expected to increase from 9 per cent of gross rate base in 2009 to 12 per cent in 2012.[348] The Commission considers that addressing factors such as the maximum investment levels of the electricity and gas distributors will help to further reduce the amount of CIAC-funded assets in the future. In that regard, in Decision 2011-134, the Commission recently increased maximum investment levels substantially for ATCO Electric.[349]

502. With respect to the TFOs, the Commission considers that the approved Rider I will likely result in a reduction in the CIAC levels of the TFOs. Further, the Commission has initiated the

[346] Decision 2004-052, page 53.
[347] Exhibit 86.01, Kathleen McShane opinion, Attachment A, PDF page 214.
[348] Ibid.
[349] Decision 2011-134, Section 5.3.

Electric Transmission Contribution Policy proceeding[350] in which it will address aspects of the AESO's customer contribution policy. The outcome of this proceeding will likely affect the level of CIAC for the TFOs in Alberta.

503. In light of these factors, the Commission considers that the equity ratios awarded in this decision for 2011 and 2012 adequately reflect the Alberta utilities' business risks, including any risks associated with the CIAC-funded assets. On a go-forward basis, the Commission will consider any concerns related to the level of CIAC-funded assets on a utility-specific basis and, if necessary, adjust the equity thickness for the utilities.

7 Rider I matters

7.1 Background

504. Following concerns expressed by certain industrial customers with respect to the up-front payment of construction contributions for system access service (i.e. transmission) connections, the AESO proposed a new "Rider I" to finance these contributions. Rider I would allow customers to pay the construction contribution principal in equal monthly amounts, over a period of up to 20 years, plus a carrying cost (similar to an interest charge) on the unpaid contribution balance. Rider I would also allow for contributions that were previously paid for transmission facilities to be refunded and then re-paid through Rider I.[351] Rider I would only be available to fund contributions to transmission facility owners (TFOs).

505. The AESO first proposed Rider I in its 2010 GTA.[352] In that proceeding, the Commission determined that Rider I should be considered in conjunction with the management fee matter and stated in Decision 2010-606 that it "makes no findings in respect of the merits of Rider I at this time...Rider I will be considered in association with the management fee in the upcoming 2011 Generic Cost of Capital proceeding."[353]

506. The Utilities supported Rider I[354] because they are concerned about the increasing levels of customer contributions, including contributions to the TFOs by the distribution facility owners (DFOs).[355] Contributions by DFOs to transmission substation costs result in a transfer of rate base from a transmission utility to a distribution utility. High levels of contributed assets reduce the amount of a utility's rate base that can earn a return on capital for rate making purposes.

507. In addition to supporting Rider I, the Utilities proposed a management fee as compensation for managing the contributed assets.[356] This is discussed in detail in Section 6 above.

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350 Proceeding ID No. 1162.
351 Exhibit 77.02, Appendix B – Previously-Filed Evidence on Amortized Construction Contribution Rider I, page 36 of 58, paragraph 191, PDF page 32.
352 Alberta Electric System Operator, 2010 ISO Tariff Application, Application No. 1605961, Proceeding ID No. 530.
353 Decision 2010-606, page 58, paragraph 302.
354 Exhibit 209.01, written argument of the utilities, page 67, paragraph 266.
355 Exhibit 86.01, opinion on management fee and Rider I, pages 6-7.
356 Exhibit 86.01, opinion on management fee and Rider I, pages 2-3.

7.1.1 Current contribution mechanics

508. A connecting customer must provide financial security up to the amount of the TFO's maximum investment level. This financial security must be in the form of a guarantee, cash deposit or irrevocable letter of credit from a Canadian chartered bank, credit union, trust company or other financial institution with a minimum senior unsecured long-term debt A- credit rating. The financial security must also be to the satisfaction of the TFO.

509. If the costs of the connection project exceed the maximum investment level, the customer must provide a construction contribution in the amount of the financial obligation above the maximum investment level. The construction contribution must be paid by way of electronic funds transfer or wire transfer to the TFO.

510. After the commencement of commercial operation of the connection project, the TFO returns any security held for the connection project, the construction contribution is not returned to the customer, but held by the TFO as part of its contributions in aid of construction (CIAC).

7.1.2 Mechanics of Rider I

511. As in the current contribution regime, until a connection project reaches commencement of commercial operation, the customer would be required to provide financial security for all the costs incurred by the TFO up to the maximum level of utility investment allowed by the Commission. For expenditures above the maximum utility investment allowed by the Commission, the customer would still be required to provide a cash contribution to the TFO to the full amount of the connection project. However, if Rider I were in effect, the customer may request that this cash contribution be repaid to the customer by the TFO after the commencement of commercial operation.[357]

512. The contribution refund would then be converted into an obligation to the AESO and paid by way of monthly payments to the AESO under Rider I. The Rider I amounts collected by the AESO would be included in the AESO's revenue forecast and would therefore offset amounts to be collected from other market participants. The amount of the contribution refund would be added to the TFO's capital invested in rate base since the balance of the TFO's no cost capital would be reduced by that amount. Because the amount of the refunded contribution would add to the TFO's capital invested in rate base, the TFO's revenue requirement would increase. This higher revenue requirement would be recovered through Rider I payments from the AESO to the TFOs.

513. The changes in the TFO's revenue requirement would be reflected in the TFO tariff paid by the AESO[358] and recovered by the AESO through Rider I.

514. The calculation of monthly Rider I payments would be made in accordance with a formula set out in Rider I, which is designed to exactly match the cost differential in the TFO's revenue requirement that will result from the elimination of the contribution. The AESO

[357] The request to have the contribution refunded under the Rider I regime could be made by a customer at any time, and the amount of the contribution refund would be calculated as the amount that has not yet been recovered through transmission rates.

[358] Exhibit 77.02, Appendix B – Previously-Filed Evidence on Amortized Construction Contribution Rider I, AML.AESO-002(c), PDF page 12 of 35.

submitted that Rider I payments would leave the TFOs unaffected, as they can continue to file their revenue requirements for approval with the Commission.[359]

515. The AESO submitted that the fundamental purpose of Rider I is to allow the highest value use of capital by the entities involved.[360] It would free up customer capital to be invested in their businesses, while the transmission connection asset would be financed by the TFO's capital. The proposed Rider I would provide:

> …market participants with an option to amortize and pay construction contributions over a period of up to 20 years, rather than in full prior to construction... Rider I is proposed to be available for system access services under both Rate DTS [demand transmission service] and Rate STS [(generator) supply transmission service], and is designed to address the financial aspects of the proposed approach, including risk of default, such that market participants who do not select the option are unaffected by those who do.[361]

516. When asked by the Commission panel if there is a concern that Rider I could potentially reallocate resources in the economy in a sub-optimal manner, the AESO's witness stated that:

> Ultimately Rider I would end up in some reallocation of resources. It seems to us when we've talked about it that it should result in a more optimal allocation of resources in that the ownership and operation of the facilities will be put to the party that has the expertise in that area.[362]

517. The AESO submitted that the principle difference between the form of Rider I proposed in this application and Rider I as it was originally proposed in the AESO's 2010 GTA, is the requirement for the customer to provide financial security in the amount of the construction contribution remaining outstanding during the Rider I term.[363] The AESO indicated that the financial security would be in the form of a letter of credit or other financial security from a financial institution.[364] There would be no requirement for financial security from a DFO regulated by the Commission.[365] The AESO submitted that the requirement for financial security would eliminate any risk of default arising from utilization of Rider I.[366]

518. The AESO witness indicated that Rider I is in the public interest because:

> The proposed implementation of Rider I, together with the provision of financial security … ensures that other market participants are not harmed by Rider I. In addition, Rider I facilitates the most efficient use of capital for both market participants and transmission facility owners. The AESO therefore believes Rider I contributes to economic efficiency, which is in the public interest.[367]

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359 Transcript, Volume 4, page 479, line 10 to page 489, line 25.
360 Exhibit 77.01, AESO evidence on Rider I matters, page 2 of 8, paragraph 12.
361 Exhibit 77.02, page 58 of 268, paragraph 290, PDF page 2.
362 Transcript, Volume 4, page 505, lines 10-15.
363 Alberta Electric System Operator, 2010 ISO Tariff Application, Application No. 1605961, Proceeding ID No 530.
364 Transcript, Volume 4, page 476, lines 11-13.
365 Exhibit 77.01, AESO evidence on Rider I matters, Appendix A, subsection 3(1).
366 Exhibit 77.01, AESO evidence on Rider I matters, page 4 of 8, paragraph 23.
367 Transcript, Volume 4, page 473, line 20 to page 474, line 2.

7.2 Views of the parties

519. IPCAA fully supported Rider I as proposed by the AESO in this proceeding and recommended that it be approved for immediate implementation. IPCAA also requested that Rider I be made available for all transmission-connected customers, including customers who contract directly with the AESO and those who contract with a DFO, which "flows through" the AESO's tariff charge to the customer. Therefore, IPCAA recommended that, should the Commission approve Rider I, that it also direct the DFOs to also implement Rider I in a timely fashion.[368]

520. As further discussed below, the Utilities, the UCA and the CCA supported Rider I with some exceptions and qualifications.

7.2.1 Risk of default

521. One of the primary concerns with Rider I as originally proposed in the AESO's GTA was with the risk borne by all customers if a Rider I customer defaulted. In his testimony, the AESO witness stated:

> So my understanding is that the risk lies with the AESO and other ratepayers. During the construction phase of that line, we do require the market participant to put up financial security for the cost of the line, even that amount covered by investment. So that covers any risk up to the commercial operation date, even if the line is fully covered by investment.[369]

522. The AESO submitted that the risk of default has been fully mitigated by its right to deny a customer's request for Rider I, the availability of Rider I only after commercial operation of the connection facilities, and the requirement of a customer to provide security for any unrecovered construction contribution during the Rider I term.[370]

523. The AESO acknowledged that, in the event that the customer defaulted on its Rider I payments and the financial institution that provided the financial security was failing at the same time, the unrecovered balance from that customer would be recovered from the other customers.[371] However, the AESO also stated:

> So it seems like that potential eventuality of simultaneous collapse of the market participant and the party providing their financial security without foreknowledge of the AESO, that seems like an extremely small risk.[372]

7.2.2 Mandatory requirement of Rider I for DFOs

524. The UCA supported Rider I as proposed by the AESO with one qualification. The UCA submitted that for a DFO Rider I should be mandatory if it has the same tax status as the TFO and particularly if it is part of the same company as the TFO.[373] The UCA stated that because the DFO is likely to have a greater equity thickness than the TFO, distribution rate payers would be

368 Exhibit 212.01, IPCAA argument, page 19, paragraphs 71-72.
369 Transcript, Volume 4, page 516, lines 5-11.
370 Exhibit 206.01, AESO argument, page 2, paragraph 8.
371 Transcript, Volume 4, page 477, line 23 to page 478, line 14.
372 Transcript, Volume 4, page 500, lines 3-6.
373 Exhibit 210.02, UCA argument, pages 65-66, paragraph 324.

better off if the DFO's contribution were financed by Rider I.[374] Second, the UCA submitted that this recommendation is critical if the Commission approves a management fee because of the possibility of "double-dipping"; that is, the scenario in which a TFO would have the asset in rate base, while a DFO owned by the same parent company was collecting a management fee on a contributed asset. The UCA also stated that if the Commission rejected the management fee, as recommended by the UCA, most of its concerns in this area would be alleviated. Nonetheless, the UCA argued, in principle, if the TFO has a lower cost of capital than the DFO, there would still be an advantage to customers if the DFO opted for Rider I, even in the absence of a management fee.[375]

525. The CCA recommended that Rider I be approved as filed by the AESO subject to adequate "prudential requirements" (financial security).[376] The CCA also submitted that there would be a need for further hearing process to adjust TFO rates if the Commission approves Rider I. Like the UCA, the CCA also recommended that, for DFOs, Rider I should be mandatory and suggested that this may entail adjustments to DFO revenue requirements as well.[377]

526. In response to the submission by the UCA that Rider I should be mandatory for all DFOs, the Utilities stated that there is no rational basis for creating a distinction between standalone and integrated utilities. The Utilities submitted that all utilities are subject to the standalone principle; and therefore corporate affiliations should not necessitate use of Rider I any more than they should be a determinant of the appropriate compensation for CIAC.[378] Therefore, the Utilities submitted that Rider I should be optional for all market participants.

7.2.3 Option to enter into and leave Rider I

527. The Utilities supported Rider I as proposed by the AESO with the following modification. The Utilities submitted that the option to convert to Rider I should be a one-time option to be exercised by a market participant either within six months of commencement of commercial operation for new projects or within six months from the date Rider I becomes available for existing projects and the decision to opt for or against Rider I should be permanent. The Utilities submitted that this modification to the Rider I proposal is necessary to prevent potential hardship to the TFOs during periods of capital restraint. The Utilities noted that the AESO would have the ability to refuse or rescind Rider I, however they submitted that this provision would not provide adequate assurance that the opportunity to opt into and out of Rider I would not lead to abuse.[379]

528. In response to the Utilities' suggestion that Rider I be restricted to a one-time only conversion, the AESO submitted that this restriction would likely reduce the utilization of Rider I because it:

- would not allow sufficient time for market participants to assess the implications of Rider I;

[374] Exhibit 210.02, UCA argument, page 65, paragraph 320.
[375] Exhibit 221.02, UCA reply argument, page 28, paragraph 117.
[376] Exhibit 211.01, CCA argument, page 36, paragraph 82.
[377] Exhibit 203.01, CCA response to AUC questions, Q7.
[378] Exhibit 209.01, Utilities argument, page 68, paragraph 269.
[379] Exhibit 209.01, Utilities argument, page 69, paragraphs 274, 276 and 277.

- would not allow market participants who paid construction contributions in the past to utilize Rider I;

- could discourage market participants by requiring them to 'lock into' the new and unfamiliar Rider I approach;

- provides an unnecessary restriction in light of the risk mitigation provided by the financial security requirements incorporated into Rider I; and

- is not necessary to prevent repeated or frequent conversions to or from Rider I, which the AESO can address through it ability to rescind or deny a request for Rider I.[380]

7.2.4 Requirement for TFOs to file adjustments to their approved GTAs

529. On July 15, 2011, the Commission issued additional information requests to all parties. Question 7 asked:

> If the Commission adopts Rider I, should TFOs file adjustments to their approved general tariff applications to reflect any Rider I adjustments?[381]

530. In response to this question, the AESO stated that it would likely take up to two years for Rider I utilization to stabilize. During that transition period, the AESO suggested that TFOs could adjust for Rider I impacts through deferral account reconciliations or other means, including refiling of the TFO's general tariff applications. After the transition period, the AESO submitted that TFOs could file and receive approval for tariff applications in the traditional manner.[382]

531. IPCAA's response echoed the AESO's submission. IPCAA submitted that in the short term, Rider I adjustments for TFOs could be handled through deferral accounts and in the long term, could be forecasted and included in revenue requirements in the TFOs' GTAs.[383]

532. The UCA only stated that Rider I adjustments should not start until appropriate filings have been made and reviewed.[384]

533. As noted above, the CCA stated that there would be the need for a further hearing process to adjust TFO rates. The CCA also recommended that Rider I be required for all DFOs, and this may require adjustments to DFO revenue requirements as well.[385]

534. The Utilities stated that there would be no need for the TFOs to file any changes to their approved revenue requirements as a result of Rider I. Instead, the Utilities submitted that there would need to be a procedural change required to flow through the amount the AESO bills the Rider I customers to the TFOs. The Utilities submitted that, "the costs arising from Rider I would

[380] Exhibit 77.01, AESO argument, page 2, paragraph 12.
[381] Exhibit 197.01, AUC additional information requests, page 2.
[382] Exhibit 200.01, AESO responses to AUC additional information requests, page 3, paragraphs 11-14.
[383] Exhibit 202.01, IPCAA responses to AUC additional information requests, page 4.
[384] Exhibit 210.02, UCA argument, page 66, paragraph 325.
[385] Exhibit 203.01, CCA responses to AUC additional information requests, Q7.

then be directly billed and collected by the AESO from that customer. The AESO would then pass on the billed Rider I amounts to the TFO."[386]

535. In response to the Utilities' submission regarding a procedural change to flow through the Rider I amounts to the TFO, the AESO stated:

> …there is no need to add the complexity of accounting for specific billed Rider I amounts to transmission facility owners…a transmission facility owner can continue to forecast its rate base net of constructions contributions after implementation of Rider I and the appropriate amounts will be recovered by the AESO from [customers].[387]

7.3 Commission findings

536. In its 2010 GTA application, the AESO proposed Rider I as a solution to the considerable increase in accumulated customer contributions on the balance sheets of the TFOs in recent years. Rider I was supported by a number of industrial customers. The central matter to be determined with Rider I is whether it is in the public interest to permit the conversion of future and existing lump sum contributions from AESO customers into an amortized stream of payments, as a means of alleviating the potential problem of accumulated customer contributions for the TFOs.

537. In the AESO's 2010 GTA proceeding, parties expressed concerns about the AESO's original Rider I proposal. They were concerned that customers other than the Rider I customers might end up bearing the risk of a credit default by a Rider I customer. The Commission is satisfied that the requirement that a Rider I customer post financial security has alleviated most of the concerns about Rider I that parties had expressed. In addition, the Commission finds that the implementation of Rider I may also assist in the credit metrics of the TFOs.[388]

538. Accordingly, the Commission approves Rider I in principle. The Commission directs the AESO to file a specific Rider I tariff application which will give effect to this approval while addressing the following matters.

539. First, the Utilities recommended that the decision by a customer to adopt Rider I should be irrevocable and that Rider I should remain in place for the term agreed to by the customer. The Commission finds that the decision by a customer to adopt Rider I should not be irrevocable. The AESO argued that the up take of Rider I may be limited if the decision to adopt Rider I is irrevocable. The Commission considers that the value of adopting Rider I, as a means of alleviating the accumulated customer contributions on the balance sheets of the TFOs, may be constrained if customers are not allowed to opt out. In addition, the Commission expects that the AESO's ability to deny or rescind Rider I will provide the necessary protection for the TFO's and prevent Rider I customers from abusing the opt out option. The Commission therefore expects that the AESO will include adequate terms and conditions in its Rider I tariff application to prevent abuse of the Rider I opt out option.

540. Second, the Utilities recommended that there should be a one-time limited opt-in period for customers to finance their existing accumulated balance of contributed capital through

386 Exhibit 199.01, Utilities responses to AUC additional information requests, question 7, page 2.
387 Exhibit 216.01, AESO reply argument, pages 2-3, paragraph 18.
388 AltaLink 2009-2010 General Tariff Application, Application No. 1587092, Proceeding ID No. 102, Exhibit 226.01.

Rider I, The Utilities argued that, in the absence of an opt-in period, there is the potential for financial harm to the TFOs during periods of capital restraint, arguably because a TFO may not be able to raise sufficient capital to replace the customer contributions. The AESO argued that an opt-in period may not give customers ample time to assess the implications of Rider I, which may limit the uptake of Rider I. Again, the Commission considers that the value of adopting Rider I, as a means of alleviating the accumulated customer contributions on the balance sheets of the TFOs, may be constrained if there is an opt-in period. Therefore, the Commission does not accept the recommendation by the Utilities regarding the limited one-time offer for Rider I. However, the Commission is also concerned that uncontrolled entries and exits into and out of Rider I could unduly complicate forecasting for utilities. The Commission accepts the argument of the AESO that its ability to deny or rescind Rider I will prevent customers from abusing Rider I. Accordingly, the Commission expects that the AESO will include adequate terms and conditions in its Rider I tariff application to prevent this type of abuse of Rider I by customers to the detriment of the TFOs.

541. Third, the Commission is concerned that the term of the Rider I payments may not match the depreciation lives of the asset financed by way of Rider I. This would, in turn, require that the remaining depreciation expense for the asset financed by Rider I, beyond the Rider I amortization term, be included in the TFO's revenue requirement and be paid for by customers other than the Rider I customer. The Commission is of the view that no one, other than the customer who is adopting Rider I, should be required to pay for the recovery of the cost of any portion of the assets financed by Rider I. The Commission expects that the AESO's Rider I application will resolve this issue.

542. Finally, with respect to any residual concerns regarding other customers bearing the risk of a credit default by a Rider I customer, the Commission reiterates its view that no customer, other than the customer who is adopting Rider I, should be required to pay for the recovery of the cost of any portion of the assets financed by Rider I. With respect to this matter, the Commission agrees with the AESO that the likelihood of a customer becoming insolvent at the same time as the backer of it financial security becomes insolvent is extremely small. However, the Commission finds when a utility asset is stranded and is no longer required to be used for utility service, any outstanding costs related to that asset cannot be recovered from other customers. The Commission relies on the Decision of the Supreme Court of Canada in *Stores Block*[389] for this conclusion. In that decision, the Court states that any assets that are no longer required to be used in utility service are to be removed from rate base.

543. Notwithstanding the submissions of the AESO and other parties referenced in Section 5.5.2 above, that ratepayers rather than utility shareholders are at risk for stranded TFO assets, The Commission is mindful of the conclusions of the Alberta Court of Appeal that assets that are not being used for utility services cannot remain in rate base. In *Carbon*,[390] the Court of Appeal stated at paragraph 29:

> [29] The Act does not contain any provision of presumption that once an asset is part of the rate base, it is forever a part of the rate base regardless of its function. The concept of assets becoming "dedicated to service" and so remaining in the rate base forever is inconsistent with the decision in *Stores Block* (para. 69). Such an approach would fetter the discretion of the Board in dealing with changing circumstances. Previous inclusion in

389 *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4 (*Stores Block*).
390 *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2008 ABCA 200 (*Carbon*).

> the rate base is not determinative or necessarily important; as the Court observed in *Alberta Power Ltd. v. Alberta (Public Utilities Board)* (1990), 72 Alta. L.R. (2) 129, 102 A.R. 353 (C.A.) at pg. 151: "That was then, this is now."

544. In Decision 2011-176,[391] dealing with Fortis' application for special facilities charge, the Commission quoted *Stores Block* and *Carbon* and came to the conclusion that:

> Given the direction of the courts, it appears to the Commission that if a special facility customer were to abandon the facilities and they were not, within a reasonable period of time, used for other utility customers, those assets would have to be removed from rate base and Fortis shareholders, not remaining utility customers, would bear responsibility for costs.[392]

545. Therefore, the Commission considers that any stranded assets, regardless of the reason for being stranded, should not remain in rate base. The utilities must bear the risk where the assets are no longer required for the provision of utility service.

7.3.1 Other matters

546. In regards to the request by IPCAA that the DFOs be directed to implement Rider I in a timely fashion for their transmission connected customers, the Commission notes that ATCO Electric already has a rate similar to Rider I in its Rider E,[393] and that FAI has a similar special facilities charge, approved in Decision 2011-176.[394] Accordingly, the Commission expects that the DFOs will determine the level of interest in a Rider I alternative for their respective transmission connected customers and file for a tariff similar to Rider I or modify existing rates, if they deem it necessary.

547. Regarding the proposal by the UCA and the CCA that DFOs be required to take Rider I, the Commission notes the UCA's statement that, in the absence of a management fee, most of its concerns in this area are alleviated. In Section 6, the Commission rejected the management fee proposal of the Utilities, and accordingly, the Commission expects that the concerns of the UCA regarding "double-dipping" are no longer relevant.

548. The UCA and the CCA also argued that the TFOs have a lower equity thickness and consequently a lower weighted average cost of capital than the DFOs and, therefore, customers would be better off if the DFOs were required to take up Rider I. However, the purpose of Rider I is not to place downward pressure on DFO rates, but rather to alleviate the concerns arising from increasing customer contributions for the TFOs. Finally, the Commission has initiated Proceeding ID No. 1162[395] to deal with aspects of the AESO's customer contribution policy. One component of this proceeding will be to examine whether a contribution should be

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[391] Decision 2011-176, FortisAlberta Inc., Application for Special Facilities Charge, Application No. 1606706, Proceeding ID No. 909, May 2, 2011.

[392] Decision 2011-176, paragraph 37.

[393] In Exhibit 18.04 of Proceeding ID No. 909 (FortisAlberta Inc. Application for Special Facilities Charge), in response to AUC-004(b), FAI stated: "FortisAlberta understands that ATCO Electric's first Rider E – Facility Charge arrangement was established as part of the ATCO Electric's (Alberta Power at the time) tariffs made effective January 1, 1982."

[394] Decision 2011-176: FortisAlberta Inc. Application for Special Facilities Charge, Application No. 1606706, Proceeding ID No. 909, May 2, 2011.

[395] Commission-Initiated Application - Electric Transmission Contribution Policy, Application No. 1607193, Proceeding ID No. 1162.

required between two regulated utilities which already have underlying obligations to provide service; examine the potential impact on becoming a direct connect customer if distribution facilities owners do not have to make contributions in the future; and, investigate the means of mitigating any impacts. For these reasons, the Commission will not direct the DFOs take up Rider I at this time.

7.3.2 Implementation for TFOs

549. Finally, with respect to the implementation of Rider I and its effects on the revenue requirements of the TFOs, the Commission notes that all parties except the Utilities argued that there would need to be additional filings with the Commission in order to adjust the revenue requirements of the TFOs. The Utilities suggested that Rider I payments be flowed through directly to the TFOs. Given the uncertainty of the uptake of Rider I, the Commission agrees with the AESO that it would create unnecessary administrative procedures to flow through the Rider I payments directly to the TFOs. The Commission agrees with the AESO that, during the first two years of Rider I implementation, the TFOs can accommodate increases to revenue requirements due to Rider I through a Rider I deferral account. After this period, the TFOs should be able to reasonably forecast their revenue requirement without a Rider I deferral account and can adjust their revenue requirement in their respective GTAs. The Commission therefore approves deferral account treatment for the impacts of Rider I on the TFO revenue requirements for the years 2012 and 2013.

8 Order

550. It is hereby ordered that:

(1) The Generic ROE for 2011 and 2012 is set at 8.75 per cent.

(2) The Generic ROE for 2013 is set at 8.75 per cent on an interim basis.

(3) Equity ratios for the Alberta utilities for 2011 and 2012, and until further changed by the Commission, are as set out in the table below.

(4) Rider I is approved in principle. The Commission directs the AESO to file a separate Rider I tariff application which will give effect to this approval based on the findings in this decision.

(5) The Utilities' request for a management fee as compensation for the provision of service involving assets funded by CIAC is denied.

(6) Utilities are directed to apply to adjust their revenue requirements to reflect the impacts of this decision in due course.

	Last approved (%)	Approved (%)
Electric and Gas Transmission		
ATCO Electric TFO	36	37
AltaLink	36	37
ENMAX TFO	37	37
EPCOR TFO	37	37
RED Deer TFO	37	37
Lethbridge TFO	37	37
TransAlta	36	36
ATCO Pipelines	45	45 for 2011 38 for 2012
Electric and Gas Distribution		
ATCO Electric DISCO	39	39
ENMAX DISCO	41	41
EPCOR DISCO	41	41
ATCO Gas	39	39
FortisAlberta	41	41
AltaGas	43	43

Dated on December 8, 2011.

The Alberta Utilities Commission

(original signed by)

Moin A. Yahya
Panel Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Mark Kolesar
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
Alberta Direct Connect Consumers Association (ADC) R. Secord C. Chekerda
AltaLink Management Ltd. C. Hollar M. G. Massicotte S. McDonald Z. Lazic J. Piotto J. Yeo K. Evans
ATCO Utilities O. Edmondson D. Freedman D. Wilson E. Jansen S. Mah D. Cook C. Warkentin A. Jukov B. McNabb B. Jones B. Yee D. Werstiuk L. Kizuk M. Bayley
AltaGas Utilities Inc. N. J. McKenzie R. Koizumi M. J. Vilbert S. Alexander J. Coleman C. Martin
BP Canada Energy Company (BP) C. G. Worthy G. W. Boone
Canadian Association of Petroleum Producers (CAPP) L. Manning R. Fairbairn N. J. Schultz R. Graham
Consumers' Coalition of Alberta (CCA) J. A. Wachowich A. P. Merani J. A. Jodoin

Name of organization (abbreviation) counsel or representative
The City of Calgary (Calgary) D. Evanchuk H. Johnson M. Rowe
Cold Lake Pipeline Ltd. M. Dawson S. Zubcic
EPCOR Distribution & Transmission Inc. (EDTI) J. Liteplo P. Wong
EPCOR Energy Alberta Inc. (EEAI) J. Liteplo P. Wong
ENMAX Power Corporation (EPC) D. Wood J. Neri D. Emes G. Weismiller K. Hildebrandt J. Schlauch J. Worsick
FortisAlberta Inc. T. Dalgleish, Q.C. I. Lorimer M. Stroh J. Sullivan J. Walsh
Industrial Gas Consumers Association of Alberta (IGCAA) G. Sproule
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster R. Mikkelsen S. Fulton V. Bellissimo R. Cowburn
Alberta Electric System Operator (AESO) J. Cusano J. Martin
City of Lethbridge M. Turner D. Hudson O. Lenz

Name of organization (abbreviation) counsel or representative
Nexen Marketing R. Stevens T. Eastman
City of Red Deer P. A. Smith M. Turner L. Gan
Shell Canada Energy D. Burnie
TransCanada Energy Ltd. V. Kostesky R. Stevens
Terasen Gas Inc. I. Bevacqua
TransCanada Keystone Pipeline Gp Ltd. V. Kostesky R. Stevens
TransAlta Corporation B. Smith K. Perley L. Zaitsoff P. Serafini
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary N. J. Parker

The Alberta Utilities Commission Commission Panel M. A. Yahya, Panel Chair B. Lyttle, Commission Member M. Kolesar, Commission Member Commission Staff V. Slawinski (Commission counsel) S. Russell (Commission counsel) S. Allen J. Olsen O. Vasetsky J. Thygesen K. Schultz S. Karim

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
ATCO Utilities L. Smith, QC K. Illsey	Panel 1 – ROE and Capital Structure K. McShane A. Engen Panel 2 – ATCO Pipelines Panel K. McShane E. Jansen Panel 3 – Management Fee K. McShane
AltaLink Management Ltd. H. Williamson, QC	
FortisAlberta Inc. T. Dalgleish, QC	
AltaGas Utilities Inc. N. McKenzie	
EPCOR Distribution & Transmission Inc. J. Liteplo	
ENMAX Power Corporation D. Wood	
Alberta Electric System Operator (AESO) J. Cusano	J. Martin G. Sharma
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	
Office of the Utilities Consumer Advocate (UCA) N. Parker R. McCreary	G. Roberts L. Kryzanowski W. Marcus
Canadian Association of Petroleum Producers (CAPP) L. Manning	L. Booth
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	R. Cowburn S. Fulton D. Levson E. de Palezieux

The Alberta Utilities Commission

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M. A. Yahya, Panel Chair
B. Lyttle, Commission Member
M. Kolesar, Commission Member

Commission Staff
V. Slawinski (Commission counsel)
S. Russell (Commission counsel)
S. Allen
J. Olsen
O. Vasetsky
K. Schultz
S. Karim