



September 9, 2016

Via Electronic Filing

Yukon Public Utilities Board
Box 31728
Whitehorse, YK Y1A 6L3

Attention: Mr. Robert Laking, Chair

Dear Mr. Chair:

**Re: ATCO Electric Yukon 2016-2017 General Rate Application
Response to Board Order 2016-04**

Further to Board Order 2016-04 dated September 2, 2016, ATCO Electric Yukon ("AEY") provides the following further information to the Information Requests listed below.

UCG-AEY-6 (a): AEY is to provide electronic copies of the decisions referenced in UCG-AEY-6(a) to UCG.

Response: AEY has provided the referenced decisions as UCG-AEY-6(a) Attachments 1-4 to this letter.

UCG-AEY-25(a): The Board directs AEY to provide the number of employees whose compensation was greater than \$100,000 annually in 2013, 2014 and 2015, or will be during the forecast period 2016 and 2017.

Response: Please refer to the following table for number of AEY employees with salary greater than \$100,000.

	2013	2014	2015	2016	2017
No of Employees with salary greater than \$100,000	31	32	33	33	34

UCG-AEY-30(c) and (f): AEY is directed to confirm that the current benchmark ROE of 8.75% established by BCUC pertained to a utility having a 38% equity ratio, as well as confirm that the current benchmark ROE established by the AUC does not have a provision for an add-on risk premium.

Response: Not confirmed. The current benchmark ROE established by the BCUC for the benchmark utility (FEI) is set at 8.75% and a 38.5% equity ratio. AEY can confirm that the current ROE established by the AUC does not have a provision for an add-on risk premium.

UCG -AEY-34(i), (k), and (l): The Board directs YECL to respond to UCG's question as to whether there has been any change in AEY's business, weather and power supply risks since Board Order 2014-06 that would materially impact AEY's risk profile.

Response: As discussed in the Concentric report, AEY's business, weather and power supply risks have not significantly changed since 2009 and therefore have not significantly changed from 2014.

Various IRs relating to Business Cases and project descriptions: AEY is directed to ensure that business case type descriptions are provided where necessary in response to the various noted IRs.

Response: Project descriptions along with other information has been provided (either as a Business Case or Project Completion Summary) on all projects in excess of \$500,000 in the test period (Section 14 Appendix 1-11) and for all projects where actual expenditures were 100% and \$100,000 greater than the original forecast (Section 11, Attachment 11.1-11.13) consistent with the Direction contained in Decision 2014-06.

YUB-YECL-2 (c) and (d): AEY's IR response provided examples of legislative provisions that have historically impacted AEY. However, AEY did not describe the impact of the provisions. The Board therefore directs AEY to describe how the examples of legislative provisions have historically impacted AEY's revenue requirement and to confirm that Board Orders have not historically impacted AEY's revenue requirement.

Response: As stated in YUB-YECL-2 (c-d), AEY provided two examples of legislative changes (Micro Generation policy and the Commercial Energy Incentive) which have historically impacted either the sales or costs of AEY. AEY provided additional details surrounding these programs in response to YUB-YECL-6 which provided the estimated impacts to the sales of AEY. At the end of 2015, AEY had connected 19 qualified micro-generation customers with a total capacity of 73 kW and estimated reduction of energy to be approximately 11,833 kWh. With respect to the Commercial Energy Incentive program, as provided in YUB-YECL-6 (a) Attachment 1 the Government estimated the annual energy reduction related to this initiative to be 1,305,000 kWh to 1,900,000 kWh. These programs and associated impacts were not contemplated in the original sales forecast completed for the 2013-2015 GRA. AEY confirms that Board Orders have typically not impacted AEY's revenue requirement in the past, and is unable to speculate as to the impact of future Board Orders.

YUB-YECL-27(a): AEY's response indicated that no across-the-board wage freezes were imposed in the 2014 to 2016 period and that some employees received wage increases in 2015 and 2016. The response did not provide details about whether some employees did not receive increases in 2015 and 2016. The Board directs AEY to provide details as requested — e.g. How many and what percentage did not get wage increases in 2015 and 2016?

Response: In 2015, 10 employees (15%) of the staff did not receive wage increases. In 2016, 11 employees (17%) of the staff did not receive rate increases.



YUB-YECL-39(c): AEY's IR response stated that forecast relocation costs only apply to relocation of AEY employees. The Board directs AEY to confirm whether the relocation costs for AEY employees leaving the Yukon are included in AEY relocation costs. If costs are included, AEY is further directed to provide details.

Response: Not confirmed. The actual and forecast relocation costs included in the Application include relocation costs for AEY employees arriving in but not leaving the Yukon.

YUB-YECL-50(a): AEY is directed to provide an electronic copy of the decision referred to in its response.

Response: AEY has provided the referenced BCUC decision as YUB-YECL-50(a) Attachment 1 to this letter. AEY also notes that since the filing of the information responses, the BCUC has issued Order G-129-16 regarding the Common Equity Component and Return on Equity for 2016. AEY has included this decision as YUB-YECL-50 (a) Attachment 2 to this letter.

We trust the foregoing is satisfactory. Should you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

Original Signed by James Grattan

James Grattan, CA
Director, Regulatory



EPCOR Distribution & Transmission Inc.

2015-2017 Transmission Facility Owner Tariff

October 21, 2015

Alberta Utilities Commission

Decision 3539-D01-2015: EPCOR Distribution & Transmission Inc.
2015-2017 Transmission Facility Owner Tariff
Proceeding 3539
Application 1611027-1

October 21, 2015

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EPCOR Distribution & Transmission Inc.
2015-2017 Transmission Facility Owner Tariff

1 Introduction

1. On November 25, 2014, EPCOR Distribution & Transmission Inc. (EDTI), filed an application with the Alberta Utilities Commission for various approvals associated with its transmission facility owner (TFO) function for the 2015, 2016 and 2017 test period. For the purposes of this decision, the Commission has referred to EDTI's application as a general tariff application, or GTA. Specifically, EDTI requested approval of:¹

- The transmission rates to be paid by the Alberta Electric System Operator (AESO) for the use of EDTI's transmission facilities over the test period, which are based on EDTI's forecast transmission revenue requirement. Excerpts from EDTI's updated minimum filing requirement (MFR) Schedule 3-1² of its application are reproduced below:

Table 1. EDTI transmission forecast revenue requirement

	2015	2016	2017
	(\$ million)		
Transmission tariffs	98.32	100.08	105.82
Increase from existing tariff	8.21	1.76	5.74
Annual increase	9%	2%	6%

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 3-1.

- EDTI's applied-for transmission rates, as shown in Schedule TFO-A of the application.³
- EDTI's TFO terms and conditions of service (T&Cs) under which EDTI provides transmission service to the AESO, as shown in Schedule TFO-B⁴ of its application.
- The continued use of the following existing transmission reserve and deferral accounts in the test period:
 - hearing cost reserve
 - self-insurance reserve
 - AESO directed projects deferral account
 - transmission property, business and linear taxes
 - transmission short-term incentive (STI) deferral account

¹ Exhibit 0003.00.EDTI-3539, application, paragraphs 1-4, PDF pages 14-15 of 900.

² Exhibit 3539-X0087, MFR Schedule 3-1, updated for EDTI's 2014 actual results and the 2013 Generic Cost of Capital (GCOC) Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.

³ Exhibit 0066.00.EDTI-3539, Schedule TFO-A, as applied-for.

⁴ Exhibit 0067.00.EDTI-3539, Schedule TFO-B.

- Placeholders related to capital structure and rate of return on equity for its transmission function, which were subject to the Commission's decision in the 2013 Generic Cost of Capital proceeding.
2. On November 27, 2014, the Commission electronically issued notice of the application to parties on the Commission's distribution list for proceedings related to electric utilities. The notice of application required that any party who wished to participate in this proceeding submit a statement of intent to participate (SIP) to the Commission by December 11, 2014.
3. The Commission received SIP's from the following parties:
- the AESO
 - AltaLink Management Ltd. (AltaLink)
 - ATCO Electric Ltd. - Transmission Division
 - the Consumers' Coalition of Alberta (CCA)
 - the Office of the Utilities Consumer Advocate (UCA)
4. Of those parties who filed SIPs, the UCA and the CCA actively participated in the proceeding.
5. Through a series of letters,⁵ the Commission established the following proceeding schedule:

Process step	Deadline
Information requests (IRs) to EDTI	January 16, 2015
IR responses from EDTI	February 6, 2015
Intervener evidence	March 16, 2015
IRs to interveners	March 31, 2015
IR responses from interveners	April 17, 2015
Rebuttal evidence	April 24, 2015
EDTI application updated for 2014 actual results and 2013 GCOC decision	May 22, 2015
CCA filing of updated evidence	May 29, 2015
Oral hearing – commencement	June 10, 2015
Oral hearing – conclusion	June 19, 2015
Argument	July 10, 2015 ⁶
Reply argument	July 23, 2015 ⁷

6. The Commission considers the close of the record for this proceeding to be July 23, 2015.
7. 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 arguments 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

⁵ Exhibits 0080.01.EDTI-3539, 3539-X0036, 3539-X0039, 3539-X0044, 3539-X0067, 3530-X0075 and 3539-X0078.

⁶ Transcript, Volume 7, page 1435, lines 6-7.

⁷ Ibid.

reasoning related 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 a particular matter. If a matter or request for approval included in EDTI's application is not specifically addressed in the findings, that matter or request is considered approved for the purposes of this decision.

2 Revenue requirement and application overview

8. The following table provides a high level summary of the updated transmission revenue requirement requested by EDTI for 2015, 2016 and 2017:

Table 2. Major components of the 2015-2017 transmission revenue requirement

	2015 forecast	Per cent of revenue requirement	2016 forecast	Per cent of revenue requirement	2017 forecast	Per cent of revenue requirement
	(\$ million)	(%)	(\$ million)	(%)	(\$ million)	(%)
Operating costs	32.63	33.2	33.53	33.5	35.51	33.6
Depreciation	22.27	22.7	23.84	23.8	25.19	23.8
Return on long-term debt	20.85	21.2	22.32	22.3	23.42	22.1
Return on common stock equity	19.78	20.1	20.41	20.4	21.73	20.6
Income tax expense	-	-	-	-	-	-
Revenue offsets	(0.25)	(0.3)	(0.26)	(0.3)	(0.27)	(0.3)
Deferral and reserve accounts	3.03	3.1	0.24	0.3	0.24	0.2
Total	98.31	100.0	100.08	100.0	105.82	100.0

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedules 3-1 and 28-1T.

9. EDTI described the changes in forecast revenue requirement as being related primarily to capital additions in each of the test years 2015, 2016 and 2017. Further, EDTI stated that increases in 2015 were due to the recovery of the AESO directed projects deferral account for the Heartland project and increases in operating costs related to critical infrastructure protection (CIP) cyber security standards. Increases in 2016 were due to rising asset usage fees related to the work centre redevelopment project offset by decreases in other revenue. Increases in 2017 were due to increased asset usage fees related to the work centre redevelopment project and higher property, business and linear taxes.⁸

10. The following table provides a summary of the updated forecast capital expenditures and capital additions for 2015, 2016 and 2017:

⁸ Exhibit 0003.00.EDTI-3539, application, paragraphs 17-20, PDF pages 18-19 of 900.

Table 3. Forecast capital expenditures and capital additions for the years 2015-2017

	2015 forecast	2016 forecast	2017 forecast
	(\$ million)		
Capital expenditures (cap ex)	48.6	70.1	47.8
Capital additions (cap add)	43.7	65.2	56.0

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 10-4.

11. EDTI stated in Section 13 of its application, that its TFO T&Cs were last approved in Decision [2010-116](#)⁹ in the context of an AltaLink application respecting updated T&Cs for regulated TFOs that provide service to the AESO. In that decision, EDTI was directed to adopt the T&Cs set out in Appendix 2, effective on March 18, 2010.

12. EDTI stated that it is not proposing any changes to its T&Cs in this application, and provided a copy as Schedule TFO-B.¹⁰ As there are no proposed changes to EDTI's T&Cs, the Commission confirms EDTI's continued use of the T&Cs, approved in Decision 2010-116, for 2015, 2016 and 2017.

3 Response to previous Commission directions

13. In Decision [2014-269](#)¹¹ respecting EDTI's 2013-2014 GTA, the Commission provided 38 directions to EDTI. In its compliance filing to Decision 2014-269, EDTI responded to these directions or identified the future proceedings in which the Commission's directions would be addressed.

14. The Commission found, in Decision [3474-D01-2015](#)¹² related to EDTI's compliance filing, that directions 1, 2, 3, 4, 5, 6, 7, 9, 10, 11, 12, 16, 19, 20, 29, 31 and 34 remained outstanding and applied to future GTAs.

15. The Commission, in this 2015-2017 GTA, has reviewed EDTI's responses and other information provided on the record of this proceeding pertaining to these 17 directions.

16. Based on the information and responses in EDTI's application, the Commission considers that, with the exception of directions 16, 20 and 31, EDTI has complied with the Commission's previous directions. The Commission provides general comments with respect to directions 2 and 3, and addresses EDTI's compliance with directions 16, 20 and 31, in greater detail below.

3.1 Directions 2 and 3 – Commission concerns with respect to business cases

17. In Decision 2014-269, the Commission issued the following directions to EDTI:

⁹ Decision 2010-116: AltaLink Management Ltd., Refiling of Transmission Facility Owner Terms and Conditions Pursuant to Decision 2009-248, Proceeding 474, Application 1605866-1, March 18, 2010.

¹⁰ Exhibit 0067.00.EDTI-3539, Schedule TFO-B.

¹¹ Decision 2014-269: EPCOR Distribution & Transmission Inc., 2013 and 2014 Transmission Facility Owner Tariff, Proceeding 2758, Application 1609817-1, September 18, 2014.

¹² Decision 3474-D01-2015: EPCOR Distribution & Transmission Inc., 2013-2014 Transmission Facility Owner Tariff Compliance Filing, Proceeding 3474, Application 1610936-1, February 12, 2015.

2. The direction at page 105 of Decision 2004-067, for EDTI to provide the appropriate business cases for capital expenditures in excess of \$500,000 has been satisfied. The Commission directs, consistent with Decision 2004-067 and the MFR document that is posted on the Commission's website, that EDTI shall provide business cases for capital projects and programs in excess of \$500,000, over the life of the project, clearly showing:
 - the reasons for the proposed expenditure
 - the alternatives examined
 - the incremental capital and operating costs associated with each alternative examined for a minimum 10-year period
 - the discount or investment rate used to compare alternatives and the basis for its use
 - the annual costs of each alternative for the period analyzed
 - the rationale for choosing a specific alternative, including any qualitative considerations used in choosing the alternative
 - the date of preparation and the date of approval Paragraph 45
3. The Commission has reviewed the application and is satisfied that EDTI has generally complied with this direction. The above list has been adopted in the MFRs. The Commission directs EDTI to specifically refer to either the MFRs or Decision 2004-067 in its future GTAs. Paragraph 46

18. The Commission is of the view that EDTI has generally complied with these directions. However, the Commission remains concerned with the scope and quality of some of the business cases submitted in this application. The Commission found instances where viable alternatives were limited¹³ and, in some cases EDTI did not adequately justify the projects selected relative to the identified business case criteria.¹⁴

19. The Commission reminds EDTI of its expectations with respect to the scope and quality of the information provided to parties in capital business cases in its application, which was summarized in the following paragraphs from Decision 2014-269:

81. ... the Commission found that some of the business cases provided for forecast capital projects lacked relevant information. For some business cases for which formal or empirical studies would have been helpful, the supporting information was not provided. Other business cases lacked viable alternatives and some business cases made no reference to the potential impact on operating costs while others failed to undertake a comparison of future operating costs in weighing project alternatives.[footnotes omitted]

82. The Commission recognizes that a utility may not be able to comply with all components of the business cases set out in the MFRs in all circumstances. If EDTI is unable to comply with individual requirements for business cases set out in the MFRs, it must provide, in the business case, an explanation why it is not practical to adhere to the MFRs. For example, for some business cases, there may be reasons why only one

¹³ For example, T-CBC-05 respecting substation roof replacements, EDTI only considered alternatives of (1) not replacing or (2) replacing like-for-like. The Commission considers that it may have been helpful if EDTI had considered whether there were any other feasible alternatives, such as replacing a roof with a new and improved material that may have a longer life or require less maintenance.

¹⁴ For example, T-CBC-08 respecting redundant AC and DC systems at critical substations, EDTI identified that it was considering the condition of the AC and DC systems, but did not provide the underlying criteria or assessments supporting the selected alternative.

alternative can be recommended by EDTI. EDTI should state that this is the case and explain why other alternatives could not be considered by EDTI. In other circumstances, it may not be possible to provide the incremental capital and operating costs associated with each alternative examined, for a minimum 10-year period. Again, EDTI should state that this is the case and explain why the required information could not be provided.

3.2 Direction 16 – Full-time equivalent (FTE) reallocations between operating and maintenance (O&M) and capital costs

20. In Decision 2014-269, the Commission issued the following direction to EDTI:

150. The Commission directs EDTI when filing future applications to identify and fully explain any changes it has made in its comparative analyses to the approved numbers and dollar values from previous decisions.

21. In its compliance filing to Decision 2014-269, EDTI identified Direction 16 as applying to future applications. However, in its 2015-2017 GTA, EDTI did not specifically address this direction.

22. Nonetheless, the Commission in its examination of the record of this proceeding cannot find any instances where EDTI proposed or made any changes to approved numbers or dollar values from previous decisions respecting FTE reallocations between O&M and capital costs.

23. On that basis, the Commission considers that for the purposes of this decision, EDTI appears to have effectively complied with Direction 16, but directs EDTI to confirm in its compliance filing that it has not made any changes in any comparative analyses to the approved numbers and dollar values from previous decisions with respect to FTE reallocations between O&M and capital costs. The Commission also directs that in future applications, EDTI shall expressly identify and fully explain any changes made in its comparative analyses to the approved numbers and dollar values from previous decisions or, if no such changes have been made, to indicate this in the application.

3.3 Direction 20 – Heartland project costs

24. In Decision 2014-269, the Commission issued the following direction to EDTI:

267. Further, as stated by EDTI, its future tariff applications will address “matters specifically relating to EDTI’s costs, such as corporate services cost allocations to EDTI’s portion of the Heartland Transmission Line, the application of EDTI’s depreciation methodology, etc.” Therefore, EDTI is directed in its compliance filing to explain any material impact to corporate services costs allocated to Heartland through the AESO directed projects review process. [footnotes omitted]

25. At the time of EDTI’s compliance filing respecting Decision 2014-269, AltaLink had not filed its direct assigned capital deferral account (DACDA) application, which includes both the AltaLink and EDTI portions of the overall Heartland project costs for review and approval by the Commission. EDTI explained that any material impacts to its costs related to Heartland and resulting from AltaLink’s DACDA application would be explained in a future application to the extent that the results of the DACDA review process were available.

26. At the time EDTI filed its 2015-2017 GTA, AltaLink's DACDA application¹⁵ had not yet been filed with the Commission. AltaLink's DACDA application was filed with the Commission in December 2014 and, at the time of the oral hearing with respect to EDTI's 2015-2017 GTA, the AltaLink DACDA hearing had been delayed until November, 2015.¹⁶

27. The Commission considers that EDTI's compliance with Direction 20 continues to be dependent on the finalization of costs related to Heartland in the AltaLink DACDA proceeding. On that basis, Direction 20 of Decision 2014-269 remains outstanding and is to be addressed by EDTI in its next GTA.

3.4 Direction 31 – Generic Cost of Capital decision

28. In Decision 2014-269, the Commission issued the following direction to EDTI:

429. The Commission finds EDTI's use of the most recently approved return on equity of 8.75 per cent and a capital structure of 63 per cent debt and 37 per cent common equity as placeholders for the test years to be reasonable. The Commission will direct that the return on equity and common equity percentages be trued-up as necessary to be consistent with the findings to be made through the current Generic Cost of Capital proceeding, Proceeding No. 2191, in the decision to that proceeding.

29. On March 23, 2015, the Commission released Decision 2191-D01-2015 (2013 GCOC decision), approving a return on equity (ROE) of 8.30 per cent and an equity ratio of 36.00 per cent for transmission utilities, on a final basis for 2013, 2014 and 2015. In Decision 2191-D01-2015, the Commission directed the "utilities to apply, by July 31, 2015, to adjust their respective revenue requirements for 2013, 2014 and 2015, to reflect the final approved ROE and capital structure determinations set out in this decision. These proceedings may ... be part of a larger (and possibly ongoing) application dealing with other rate matters (e.g., a general rate or tariff application)."¹⁷

30. The applied-for revenue requirement calculations in EDTI's GTA schedules¹⁸ used an ROE of 8.75 per cent and equity ratios of 37.46 per cent, 37.33 per cent and 37.23 per cent for the years 2015, 2016 and 2017 respectively, on a placeholder basis.

31. At the direction of the Commission, EDTI revised its application on May 22, 2015, to reflect, amongst other things, the updated ROE and capital structure approved in Decision 2191-D01-2015. EDTI stated that in addition to reflecting the changes in ROE and capital structure approved by the Commission in its 2015 forecast revenue requirement, EDTI also updated its 2016 and 2017 forecast revenue requirement to reflect the 2013 GCOC ROE and capital structure approved in Decision 2191-D01-2015 on a placeholder basis for each of the 2016 and 2017 test years.¹⁹

32. The applied-for revenue requirement calculations in EDTI's GTA schedules (updated for 2014 actuals and the impact of the 2013 GCOC decision) used an ROE of 8.30 per cent and

¹⁵ Proceeding 3585, AltaLink 2012 and 2013 deferral account reconciliation.

¹⁶ Transcript, Volume 2, page 401, lines 17-23.

¹⁷ Decision 2191-D01-2015, paragraph 498.

¹⁸ Exhibit 0065.00.EDTI-3539, MFR schedules, Schedule 28-1T.

¹⁹ Exhibit 3539-X0089, EDTI additional information – 2014 actuals, PDF page 29 of 35.

equity ratios of 36.27 per cent, 35.80 per cent and 36.23 per cent for the years 2015, 2016 and 2017, respectively.

33. On July 31, 2015, EDTI submitted its 2013 GCOC compliance filing application in which it requested approval of EDTI's 2013 and 2014 revenue requirement adjustments to reflect the determinations set out in Decision 2191-D01-2015; approval to adjust, as part of EDTI's 2015-2017 TFO tariff refiling, EDTI's applied-for 2015 transmission revenue requirement to reflect the determinations from Decision 2191-D01-2015; and approval of EDTI's proposed true-up mechanism by which the 2013-2014 true-up refund and the anticipated 2015 revenue shortfall amount be dealt with, as part of EDTI's 2015-2017 TFO tariff refiling application. This application is being addressed in Proceeding 20692.

34. On EDTI's schedule of transmission capital structure and average cost of capital²⁰ for the year 2015, on line 66 (column G), EDTI has updated the ROE to reflect the 2013 GCOC decision approved amount of 8.30 per cent. However, on lines 64 and 66 (column E), EDTI did not reflect the 2013 GCOC decision approved debt and equity ratios of 64.0 per cent and 36.0 per cent, respectively.

35. The Commission considers that, for ratemaking purposes, EDTI's 2015 forecast revenue requirement should reflect the 2013 GCOC decision approved debt and equity ratios of 64.0 per cent and 36.0 per cent, respectively. The Commission's findings with respect to EDTI's 2015 forecast debt and equity ratios are found at Section 11.2 of this decision.

36. The Commission expects that EDTI's compliance with Direction 31 will be addressed in Proceeding 20692 and in EDTI's compliance filing to that decision. However, the Commission directs EDTI, in its compliance filing to this decision, to recalculate its forecast transmission capital structure, and average cost of capital and transmission return on rate base for 2015, using the Commission-approved debt and equity ratios of 64.0 per cent and 36.0 per cent respectively. In the order section of this decision (Section 13), the Commission has included additional time for EDTI to submit its compliance filing, to allow EDTI the opportunity to include any adjustments to its generic cost of capital for 2013 and 2014 that may arise from the decision in Proceeding 20692.

3.5 Decision 2013-417 – Utility Asset Disposition, Direction 2

37. In Decision 2013-417,²¹ the Commission issued the following direction to all Alberta utilities:

327. In order to give effect to the court's guidance that the "rate-regulation process allows and compels the Commission to decide what is in the rate base, i.e. what assets (still) are relevant utility investment on which the rates should give the company a return," the Commission directs each of the utilities to review its rate base and confirm in its next revenue requirement filing that all assets in rate base continue to be used or required to be used (presently used, reasonably used or likely to be used in the future) to provide utility services. Accordingly, the utilities are required to confirm that there is no surplus land in rate base and that there are no depreciable assets in rate base which should be treated as extraordinary retirements and removed because they are obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for

²⁰ Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 28-1 T, lines 64 and 66.

²¹ Decision 2013-417: Utilities Asset Disposition, Proceeding 20, Application 1566373-1, November 26, 2013.

future needs, property used for non-utility purposes, property that should be removed because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or un-expected and permanent shutdown of an entire operating assembly or plant. As stated above, these types of assets must be retired (removed from rate base) and moved to a non-utility account because they have become no longer used or required to be used as the result of causes that were not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions. Each utility will also describe those assets that have been removed from rate base as a result of this exercise. At this time, the Commission will not require the utilities to make additional filings to verify the continued operational purpose of utility assets.
[footnotes omitted]

38. During the hearing, Commission counsel questioned EDTI as to whether the detail requested in paragraph 327 of Decision 2013-417 had been provided in its 2015-2017 GTA. EDTI stated that while the information had not been provided in the GTA or supplementary information, a review of all transmission rate base had been conducted and it had concluded that all transmission assets are used, presently used, and would be used in the future. EDTI also confirmed that it did not anticipate that any assets would not be used or required to be used during the test period.²²

39. The Commission is satisfied that EDTI has complied with Direction 2 of Decision 2013-417.

4 Three-year test period and factors related to the economic downturn

40. EDTI applied for its TFO tariff to be effective for the three-year period, from 2015 to 2017. EDTI stated that a three-year test period would provide benefits in the form of reduced costs and increased regulatory efficiency, and provide greater incentives for EDTI to identify and implement cost saving measures during the test period that would ultimately benefit customers over the long term.

41. EDTI submitted that a three-year test period was approved for EDTI in Decision 2008-125²³ related to its 2007-2009 tariff application, and in Decision 2006-024²⁴ for ATCO Electric Ltd.'s 2005-2006 general tariff application, the Commission endorsed the merits of having rates continue beyond a two-year test period.²⁵

42. In addition, in argument EDTI stated that a three-year test period would align with the end of the performance-based regulation (PBR) term for EDTI's distribution function, which would result in additional administrative and regulatory efficiencies and that the longer term is more consistent with prospective rate-making.²⁶

43. In response to concerns raised by interveners, EDTI argued that the recent decline in oil prices would have little meaningful impact on its 2015-2017 forecast revenue requirement and

²² Transcript, Volume 2, pages 376-379.

²³ Decision 2008-125: EPCOR Distribution & Transmission Inc., 2007-2009 Distribution Tariff and 2007-2009 Transmission Facility Owners Tariff, Code of Conduct Exemption, Proceeding 14, Application 1558686-1, December 3, 2008.

²⁴ Decision 2006-024: ATCO Electric Ltd., General Tariff Application, Application 1399997, March 17, 2006.

²⁵ Exhibit 0003.00.EDTI-3539, application, Section 1.1.2.

²⁶ Exhibit 3539-X0193, EDTI argument, paragraphs 14-22.

capital additions and that the Commission should not consider the current economic circumstances as an impediment to the approval of EDTI's applied-for three-year test period.²⁷ EDTI submitted that the 2008 drop in oil price did not cause a noticeable change in the number of customers or the volume of energy consumed by EDTI customers. Electric transmission utilities are a stable industry not directly impacted by a short term drop in oil prices and the impact of the decline in oil prices is offset to some extent by the Canadian dollar exchange rate. Finally, heightened transmission infrastructure activity due to aging transmission infrastructure, increasing demand and a current construction boom in Edmonton has created a tight electric utilities labour market in Alberta. EDTI's witnesses indicated in testimony that EDTI competes in a different industry, where the labour pool is different than the oil industry.²⁸

44. The CCA stated that in considering a three-year test period the Commission must weigh the regulatory efficiency arising from dealing with a three-year test period against any loss in forecast accuracy as well as any potential on the part of the applicant to overstate forecasts to safeguard against their inherent uncertainty. For the purposes of this proceeding, the CCA recommended acceptance of the three-year test period provided the forecasts of escalation rates, made post oil price collapse, are reflected so that the risk of forecast inaccuracy may be largely addressed.²⁹

45. The UCA expressed concern regarding the impact of the current economic climate on the forecasts for the test period, with specific reference to the forecast escalation rates for labour.

46. EDTI responded to the CCA that the approval of a three-year test period should not hinge on the adoption of the more recent forecast escalation rates.³⁰

Commission findings

47. The Commission agrees with EDTI's submission that there will be regulatory efficiencies and related cost savings in the approval of a three-year test period as compared to a two-year test period. The Commission also agrees with EDTI that aligning the end of EDTI's transmission test period with the end of the current PBR term for EDTI's distribution function has the potential to reduce duplicative efforts and result in further regulatory efficiencies.

48. The Commission agrees with the CCA that it must weigh the regulatory efficiency achieved from a three-year test period against any potential loss in forecast accuracy when considering whether a three-year test period should be approved.

49. The CCA did not object to a three-year test period but noted its concern that the escalation factors proposed by EDTI would not result in accurate forecasts. With respect to forecasting accuracy, given the timing of this proceeding, updated information has been made available on the record and the Commission has considered the impact of this information on the updated cost escalators in Section 7.4.4 and the timing of capital additions in Section 10 of this decision.

50. The Commission has also considered the testimony of Dr. Spare, of Quanta Technology, LLC (Quanta) regarding the possible impact of oil prices on the capital forecast. Dr. Spare

²⁷ Exhibit 3539-X0193, EDTI argument, paragraph 23.

²⁸ Transcript, Volume 2, pages 260-261.

²⁹ Exhibit 3539-X0194, CCA argument, paragraphs 9-10.

³⁰ Exhibit 3539-X0197, EDTI reply argument, paragraph 13.

indicated that the capital forecast was based on expectations 20 to 30 years out and if oil prices were to remain low for three years, there could be a delay to the forecast capital additions or some adjustment might be required.³¹

51. For the above reasons, the Commission approves use of a three-year test period, from 2015 to 2017.

5 Nature of best available information

52. In argument, the UCA referenced Mr. Baraniecki's testimony³² that due to EDTI's bottom-up approach to forecasting and the use of the best available information at the time EDTI's application was prepared, any updates during the course of the proceeding for subsequent information such as 2014 actuals would not cause EDTI to reconsider its proposed test year forecasts.³³

53. The UCA argued that EDTI's interpretation of what constitutes the best available information provided during a proceeding, was in "direct contradiction to the many prior rulings of the Commission and its predecessors, who have clearly stated that the best available information is as of the time a decision is rendered."³⁴

54. The UCA cited Decision [2010-505](#)³⁵ as informing its opinion that the best available information is what is available at the time a decision is rendered. The UCA stated that this principle had been recently reaffirmed by the Commission in Decision [2957-D01-2015](#)³⁶ and requested that the Commission confirm this approach as it relates to EDTI's current and future applications.³⁷

55. In reply argument, EDTI stated that there is no contradiction between EDTI's position and previous Commission and Alberta Energy and Utilities Board (EUB or board) decisions on the issue of best available information. EDTI agreed that the Commission will consider the best available information at the time it renders its decision as to the reasonableness and accuracy of test period forecasts, but suggested there are related aspects which the UCA has misconstrued.

56. EDTI explained that while the Commission expects a utility's application should be prepared based on the best available information at the time the forecasts are prepared, the Commission also considers additional information that becomes available during the course of a proceeding in its assessment of the utility's forecast, but only with respect to specific forecast items. Under a prospective ratemaking approach, the Commission should not generally require

³¹ Transcript, Volume 6, pages 1172-1173.

³² Transcript, Volume 5, page 878, lines 13-19.

³³ Exhibit 3539-X0192, UCA argument, paragraph 20.

³⁴ Exhibit 3539-X0192, UCA argument, paragraph 21.

³⁵ Decision 2010-505: EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff and 2010-2011 Transmission Facility Owner Tariff, Proceeding 437, Application 1605759-1, October 28, 2010.

³⁶ Decision 2957-D01-2015: Direct Energy Regulated Services, 2012-2016 Default Rate Tariff and Regulated Rate Tariff, Proceeding 2957, Application 1610155-1, July 7, 2015, where the Commission directed the use of actual information for three applied for test years, 2012-2014.

³⁷ Exhibit 3539-X0192, UCA argument, paragraph 1721.

revisions or updates to the forecasts. Such continuous amendments³⁸ would result in “having never-ending proceedings.”³⁹

57. EDTI argued that nothing has arisen since the filing of its application that suggests its forecasts remain anything but reasonable for rate setting purposes and, as such, subject to specific exemptions consistent with Commission precedent, EDTI’s forecasts should be approved as filed.

Commission findings

58. The Commission always strives to consider the best available information when rendering a decision. In Decision 2012-272⁴⁰ and Decision 2957-D01-2015, the Commission accepted the use of actual information that was available at the time of filing the application or that became available prior to the close of record of the proceeding.

59. As noted by the UCA, in Decision 2010-505, the Commission stated:

23. The Commission confirms that it requires the best available information at the time it makes its decision and confirms its views from Decision 2008-113.^[41] There, the Commission adopted the Board’s views on the use of updated information in a prospective rate-setting environment as set out in Decision 2006-004.³

In recent years, when confronted with the question of whether or not to consider events that have occurred after the preparation of revenue requirement forecasts, the Board has usually taken the position that such information will be used in assessing the reasonableness and accuracy of the forecasts and the methodology utilized in preparing the forecasts. The Board has not, however, substituted the forecasts with the updated information, except with respect to certain specific forecast items. For example, the Board has updated interest rate forecasts in determining the cost of capital, income tax rates, opening balances for plant property and equipment and has excluded amounts forecast for capital projects that did not proceed. The Board has determined that the use of updated information in these particular types of categories was in the overall public interest and had as its objective an appropriate revenue stream without undue benefit or detriment to the regulated utility. The utility has also always been able to update its application and its forecasts to reflect any unforeseen increases in costs. The Board continues to be of the view that this is the appropriate use of information that becomes available subsequent to the preparation of the forecasts underpinning an application.

On the basis that the Board should have the best available information, the Board has expressed a preference in having actuals for the full year prior to the test year where possible. Providing the Board with the best available information at the time it must make its decision, will assist the Board in determining a revenue requirement for the utility that most closely matches current expectations and

³⁸ Exhibit 3539-X0197, EDTI reply argument, paragraphs 4-8.

³⁹ Transcript, Volume 5, page 879, line 3.

⁴⁰ Decision 2012-272: EPCOR Distribution & Transmission Inc., 2012 Phase I and II Distribution Tariff, 2012 Transmission Facility Owner Tariff, Proceeding 1596, Application 1607944-1, October 5, 2012. Decision 2012-272, see paragraph 212 where the Commission directed, consistent with Decision 2010-505, where EDTI was directed to reflect all changes to the 2012 revenue requirement using 2011 actuals.

⁴¹ Decision 2008-113: ATCO Gas, 2008-2009 General Rate Application Phase I, Proceeding 11, Application 1553052-1, November 13, 2008.

conditions. Properly considered, this should reduce the initial forecasting risk to the utility and reduce the possibility of overpayment by ratepayers.

24. The Commission confirms its findings from Decision 2008-113 to the effect that it is incumbent on the Commission to make its decision using the best information available to it.⁴² [emphasis in original removed]

³ Decision 2006-004: ATCO Gas 2005-2007 General Rate Application Phase I, Application 1400690, January 27, 2006, page 3.

60. Decision 2006-024 set out principles to be considered regarding the use of actuals in determining revenue requirement:

The Board continues to be of the view that this is the appropriate use of information that becomes available subsequent to the preparation of the forecasts underpinning an application. Providing the Board with the best available information at the time it must make its decision, assists the Board in determining a revenue requirement for the utility that most closely matches current expectations and conditions. Properly considered, this should reduce the initial forecasting risk to the utility and reduce the possibility of overpayment by ratepayers. This does not mean, however, that an applicant must wait until the year prior to the first test year has ended before it can file an application. Depending on the circumstances, an applicant may be required to provide updated actual information whenever the processing of an application straddles the end of a fiscal year and the time that the actual results become available prior to the close of the evidentiary portion of the proceeding. Further, partial year results may also be required when an application is processed over an extended period of time, provided the utility is offered the opportunity to put such partial results in the proper context and to describe the limitations applicable to partial actual information.⁴³

61. The Commission considers that relying on the best available information is relevant not only in the context of the initial filing of the application but also applies during the course of the proceeding, as further information becomes available. It is incumbent on the utilities to use the best available information at the time of filing an application and it is preferable to have the actuals for a full year prior to the test year, where possible. The Commission stated in Decision 2008-113:

The Commission agrees with the Board's comments cited above, and continues to hold that an appropriate balance can be struck which allows for a utility to plan and budget according to its forecasts but that also provides the Commission with sufficient current information to enable it to assess the reasonableness of those forecasts. It is expected that a utility will put forth its best possible case in making an application for its revenue requirement. That best possible case should reflect information available to the utility that may reasonably form part of its Application and any updates thereto....⁴⁴

62. With respect to information that becomes available during the course of a proceeding, both the Commission and its predecessor have confirmed that updated information may be used for adjustments to revenue requirement or for evaluating the reasonableness and accuracy of the forecasts and the methodologies employed in generating forecasts. The Commission does not

⁴² Decision 2010-505, paragraphs 23-24.

⁴³ Decision 2006-024, page 6.

⁴⁴ Decision 2008-113, page 16.

consider that the current circumstances warrant a departure from the practice of using actuals to test forecasts or using actuals for specific adjustments to revenue requirement. In Decision 2014-269, EDTI's last transmission facility owner application for 2013 and 2014, the Commission applied the best information available to EDTI's capital additions and stated:

363. Consistent with prior Commission decisions, the Commission considers that the most accurate information available with respect to EDTI's forecast capital additions and the revised completion dates known at the time of filing its application, or information that becomes known during the course of the proceeding, should be used in assessing the reasonability of the forecast capital additions for the test years.⁴⁵ [footnotes removed]

63. The Commission will consider the forecasts submitted in the application given the best available information on the record. In the sections that follow, the Commission will discuss the impact of actual information as it relates to forecast accuracy or with respect to adjustments to the revenue requirement, as required, for costs arising from capital expenditures or operating and maintenance costs.

6 Operational performance and service quality (SAIFI and SAIDI) and forecasting of "bucket projects"

64. EDTI uses two industry reliability indices to measure transmission operating performance reliability: system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI). In its application, EDTI indicated that for the years 2009 to 2013, five-year average SAIFI and SAIDI reliability performance values of 0.28 and 20.45 minutes, respectively, were achieved. This was in contrast to five-year Canadian transmission utility average SAIFI and SAIDI reliability performances of 0.78 and 74.16 minutes, respectively.

65. EDTI did not propose any changes to service levels for transmission for the years 2015-2017.⁴⁶

66. During the oral hearing, EDTI was questioned by Commission counsel and the Commission panel on EDTI's operational performance and service quality statistics exceeding those of other transmission utilities in Canada. Specifically, the issue was raised as to whether EDTI might be managing its system in a manner that exceeds what would be considered a reasonable level of safe and reliable service at the expense of ratepayers.

67. EDTI stated that its SAIFI and SAIDI statistics do not support a view that EDTI is managing its system to achieve a level of safety and reliability that is unreasonably high. EDTI explained that the comparator Canadian transmission utilities are a mix of urban and rural, whereas EDTI's transmission system is almost entirely within an urban setting. This meant that with respect to its SAIFI performance measures, EDTI is able to more quickly respond to outages and equipment failures. For its SAIDI performance measures, the urban setting results in less vulnerability to events such as lightning, high winds and ice storms. EDTI submitted that, these factors lead to achieving higher SAIFI and SAIDI statistics than the industry averages.

⁴⁵ Decision 2014-269, paragraph 363.

⁴⁶ Exhibit 0003.00.EDTI-3539, application, paragraphs 435-442, PDF pages 164-166 of 900.

68. EDTI also discussed its obligations for reliability requirements as they fall under Section 39(1) of the *Electric Utilities Act*, SA 2003, c. E-5.1, Alberta Reliability Standards and Commission-approved T&Cs of service, and EDTI's compliance with AUC Rule 002⁴⁷ reporting requirements. EDTI stated that it has observed that electricity customers are "increasingly demanding higher levels of transmission system reliability, not reductions" and would not be willing to accept lower levels of reliability on EDTI's transmission system.⁴⁸

69. During the oral hearing, Quanta confirmed that there is an inherent level of redundancy in EDTI's transmission system but that it is not considered a luxury by the industry. An N minus one standard is required and the N minus one redundancy is usually for a single device for which an outage would create a huge disturbance.⁴⁹

70. When the Commission panel questioned whether there were industry standards or norms that would provide guidance as to when lifecycle programs should proceed, Mr. Baraniecki from EDTI responded:

I think it's probably important to clarify how we're deciding which assets to replace when. And it's not based on some economic life or even design life. I mean, that comes into play, but it's really on condition assessment. And the asset management program has condition assessment parameters built into it where we -- like Mr. Ciocoiu has mentioned, Doble testing and DG analysis, dissolved gas analysis, and those are all indicators of an asset is getting close to failing.

And our asset management program drives the lifecycle replacement. And it's those condition assessments that give us the indication and provide us the information to make decisions of what to replace when.

And it's that process that we reviewed or Quanta reviewed, and it's that process that you can compare against industry standard of how you're doing your condition assessments, how you're doing your asset management program. And you can see -- and, for lack of a better term, is your asset management program gold-plated or not, or is it lacking or not. And that's a way to view whether or not you're in this catch-22 scenario or not, is by looking at the condition assessments themselves and the program to do that.⁵⁰

71. The Commission panel also explored the concept of buckets or bucket programs/projects which had been raised by EDTI witnesses during the course of the oral hearing. EDTI agreed that the bucket terminology described a lifecycle program or portion of a lifecycle program that has been forecast based on a three-year average of historical costs, but where the scope of the specific bucket project(s) had not necessarily been identified at the time the forecast was developed. The forecast for the test period was prepared using an assumption of the number of replacements to be made in the period for the equipment type and the actual replacements made were based on the inspection and maintenance results. The expectation is that in some years, more work than assumed will be required and in other years, less work will be required.⁵¹ EDTI's witness also stated that the Commission would not be approving a bucket of costs for projects

⁴⁷ Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

⁴⁸ Exhibit 3539-X0193, EDTI argument, paragraphs 328-334, PDF pages 141-143 of 259.

⁴⁹ Transcript, Volume 6, pages 1206-1207.

⁵⁰ Transcript, Volume 5, pages 1028-1029.

⁵¹ Transcript, Volume 1, pages 127-129.

which do not have a defined scope per se but would be approving a forecast methodology with the knowledge that EDTI cannot know what exact equipment will require replacement in those project categories in advance of the test years. Also, the Commission and interveners are given the opportunity to evaluate the actual costs in subsequent applications.⁵² EDTI's witness explained that a three-year average is reasonable because as assets get older, they have a higher probability of failure or of needing to be replaced, and the number of life cycle replacement projects seems to increase from one test period to the next.⁵³

72. The Commission panel asked EDTI whether Commission approval of a bucket program created an incentive to spend the bucket. The panel also explored with EDTI a situation where the Commission reduced EDTI's forecast costs for lifecycle projects. EDTI agreed that in theory, the incentive to spend the approved forecast is there, but stated that any forecast dollars spent on an actual basis must be supported by proper justification for the project undertaken. This would include checks and balances such as EDTI's budgeting process, condition assessments, professional ethics, and an examination of prudence through the regulatory process.⁵⁴ EDTI stated it follows good industry practice in operating and maintaining its transmission system as was evidenced by the assessment and conclusions made in the independently prepared Quanta reports.^{55 56}

73. When questioned by the panel as to whether EDTI might be overly aggressive in implementing its life cycle replacement programs and whether the option of delaying projects existed, the Quanta witnesses replied that predicting an optimum project timing for asset replacement is very difficult. In many cases, the life cycle replacements are of a first generation nature which can't always be related to age or history, but must be tied to monitoring of asset condition.

74. The Quanta witnesses also commented that the concept of a bucket of costs is sometimes referred to as a blanket project in the utility industry, and is often used to provide "funding for all of those things that happen that you can't identify at the time the budget is formulated."⁵⁷

75. The Quanta witnesses rejected the concept that transmission system redundancy builds in a buffer of time allowing EDTI to delay the life cycle replacement of its transmission system assets. The Quanta witnesses considered that the tolerance of the regulator and the public for decreases in service reliability is low, and the obligation to provide safe and reliable service to customers is "foremost in the mind of utility management in all cases ..."^{58 59}

76. In response to an undertaking, EDTI identified all projects that would be considered to be forecast as a bucket. The total forecast capital additions for the projects is \$2.36 million, \$2.50 million and \$2.60 million for the years 2015, 2016 and 2017, respectively.⁶⁰

⁵² Transcript, Volume 4, pages 672-674.

⁵³ Transcript, Volume 3, page 572.

⁵⁴ Transcript, Volume 5, pages 1032-1033 and 1035.

⁵⁵ Transcript, Volume 5, page 1033.

⁵⁶ Exhibit 3539-X0193, EDTI argument, paragraphs 335-343, PDF pages 144-151 of 259.

⁵⁷ Transcript, Volume 6, pages 1176-1177.

⁵⁸ Transcript, Volume 6, page 1203, lines 11-12.

⁵⁹ Transcript, Volume 6, pages 1201-1205.

⁶⁰ Exhibit 3539-X0182.01, response to undertaking at Transcript, Volume 6, line 1177.

77. The UCA argued that the use of a bucket approach to forecasting is in contrast to EDTI's bottom-up forecasting process in that it is based on historical trends and expectations that "stuff" is going to happen that can't be fully tested until subsequent test years. The UCA also expressed concern that the 2015-2017 bucket forecasts were based on a three-year average that did not include 2014 actuals and further, that there is an incentive to seek and spend as large a bucket as possible without sufficient analysis of the necessity and prudence of the underlying projects.⁶¹ The UCA noted that should the Commission deny a forecast of costs, it would not preclude EDTI from requesting approval to recover prudently incurred costs in a future application.⁶²

78. EDTI stated that its forecast for bucket projects is linked with and complimentary to EDTI's overall bottom-up forecasting approach. The bottom-up approach reflects how EDTI manages its business and is based on sound budgeting and cost management principles that support reliable and prudent cost forecasts.⁶³

Commission findings

79. The Commission considers that the costs associated with certain projects or categories of projects can vary significantly from one year to the next depending on factors outside of a utility's control. Therefore, the Commission is of the view that the methodology of using historical actual costs to forecast capital projects can be a reasonable alternative to bottom up forecasting or more defined cost forecast methodologies in certain circumstances.

80. Given the inconsistency of costs from one year to the next, or from one forecasting period to the next, the Commission considers that a three-year average using the most recent actuals available is sufficient for the purposes of forecasting life cycle projects such as emergency replacement of equipment. The Commission acknowledges that project cost forecasts are uncertain and can differ in any given year due to unforeseen circumstances. The expectation is that the cost forecasts would, on average, be close to the actuals over time, as over-forecasting and under-forecasting are experienced. For all projects that are forecast as a bucket, the Commission directs EDTI to use a three-year average of 2012 to 2014 actuals in its compliance filing to this decision.

81. The Commission has considered the evidence on the record of the proceeding and has given considerable weight to the testimony of the expert Quanta witnesses on the subject of bucket projects. The Commission is not opposed in principle to the concept of a bucket project and finds that, generally, this is consistent with good utility maintenance and life cycle replacement practices. While, as EDTI acknowledged, there may be some incentive to spend an approved bucket even if a project is not critical in the test period, the Commission also recognizes that it is incumbent on the applicant to demonstrate the costs incurred for a project category are prudent. The Commission notes that the reasonability of actual costs for all life cycle projects undertaken during the test period will be evaluated in the next GTA as part of opening rate base.

82. With respect to EDTI's operational performance and service quality statistics exceeding those of other transmission utilities in Canada, the Commission recognizes that the comparator SAIFI and SAIDI statistics on the record of the proceeding include both urban and rural utilities,

⁶¹ Exhibit 3539-X0192, UCA argument, paragraphs 5-6, PDF page 3 of 22.

⁶² Exhibit 3539-X0192, UCA argument, paragraph 12, PDF pages 5-6 of 22.

⁶³ Exhibit 3539-X0197, EDTI reply argument, paragraph 143, PDF pages 54-55 of 80.

and may not provide an accurate comparison. Nonetheless, the Commission is cognizant that EDTI's SAIFI and SAIDI results exceed the average for other transmission utilities by a significant amount. EDTI is directed to file a comparison of its SAIFI and SAIDI results with those of other urban transmission utilities, to the extent they are available, at the time of its next GTA.

7 Transmission operating costs overview

7.1 Direct operation and maintenance costs

83. EDTI provided historical and forecast transmission O&M costs classified on a uniform system of accounts (USA) and operating cost category basis. The following table shows EDTI's forecast O&M costs by operating cost category:

Table 4. Direct O&M costs by cost category 2013-2017

Description of O&M cost category	2013 Decision 2012-272	2013 actual	2014 Decision 2012-272	2014 actual	2015 forecast	2016 forecast	2017 forecast
	(\$ million)						
Labour	8.52	8.71	9.52	9.44	10.34	10.92	11.14
Overtime	0.43	0.75	0.46	0.62	0.58	0.60	0.62
Fringe and burden	1.49	1.31	1.88	1.75	2.25	2.54	2.68
Subtotal – labour related costs	10.44	10.77	11.86	11.81	13.17	14.06	14.44
Contractor services	2.62	2.25	2.07	2.14	2.98	1.61	1.63
Materials and supplies	0.81	0.68	0.80	0.70	0.73	0.71	0.74
Other	1.88	2.04	1.90	2.36	2.19	2.25	2.30
Total operating costs by cost category	15.76	15.75	16.62	17.00	19.06	18.64	19.11
Over (under) 2013 and 2014 decision to actuals or forecast \$		(0.01)		0.38	2.44		
Over (under) 2013 and 2014 decision to actuals or forecast %		0.0%		2.3%	14.7%		

Source: Exhibit No. 87, extracted from MFRs Schedule 5-4 less Account 935.

84. EDTI has applied for O&M costs of \$19.06 million in 2015, \$18.64 million in 2016 and \$19.11 million in 2017. The preceding table shows an increase in total operating costs of 14.7 per cent from the 2014 decision amount of \$16.62 million and 2.3 per cent from 2014 actual O&M costs to the 2015 forecast amount of \$19.06 million. EDTI explained that the forecast increase is mainly due to increased workloads for operating and capital, and inflation.⁶⁴ Labour, related benefits and contractor services represent approximately 80 per cent of O&M costs.

85. In 2015, a one-off single year project using contractors to develop processes and provide training to area staff to ensure compliance with supervisory control and data acquisition (SCADA) CIP (cyber security standards) is included in the contractor costs component of the operating costs forecast, at a cost of \$1.20⁶⁵ million. There was also a change in accounting for

⁶⁴ Exhibit 3539-X0005, IR responses: EDTI-AUC-2015FEB06-064, EDTI-AUC-2015FEB06-027, EDTI-AUC-2015FEB06-106; and Exhibit 0003.00.EDTI-3539, application, page 61, paragraphs 171 and 172.

⁶⁵ Exhibit 0003.00.EDTI-3539, application, paragraph 17.

the STI program as discussed in Section 7.4.2, which affects the comparability of total operating costs.

86. The Commission will examine in Section 7.3 the components of the forecast of labour related costs.

7.2 O&M high level metrics analysis

87. As part of the CCA evidence, Mr. Retnanandan recommended that the Commission adopt a high level metrics analysis for O&M costs to provide an indication of the appropriate level of cost changes for the test period.⁶⁶

88. Mr. Retnanandan explained the high level analysis as follows:

[The analysis] takes the O&M expenses (excluding asset usage fees) included in EDTI's revenue requirement, adjusts them for costs that are externally imposed (example: Alberta Reliability Standards) and scope changes or accounting changes (example: capitalization of short term incentives) to arrive at an adjusted O&M expense level for each year. The adjusted O&M expenses are then adjusted to constant dollar O&M expenses using the Alberta CPI [Consumer Price Index] and then levelized to recognize system growth, using 2013 as the base year (i.e. 2013=100 for all indices).⁶⁷

89. In his evidence Mr. Retnanandan acknowledged EDTI's concerns with a high level analysis of O&M expenses⁶⁸ and explained how these had been addressed in his analysis.

90. In response to a concern from EDTI that the number of delivery points, megawatts (MW) of power delivered, kilometres (km) of line and number of substations are each not suitable indicators of growth, Mr. Retnanandan used a composite growth indicator of the number of delivery points, MW of power delivered, km of line and number of substations, stating that the composite growth indicator would tend to dampen year-over-year fluctuations in individual growth indicators and would provide a proxy measure of system growth.

91. In response to EDTI's additional concern regarding the fluctuations in the volume of external requests and the timing of FTE additions, Mr. Retnanandan used three-year averages in his analysis.

92. In Mr. Retnanandan's analysis, adjustments were made for changes in AESO rules and the accounting change to capitalize short-term incentive payments. Mr. Retnanandan submitted that a claim from EDTI that aging assets may contribute to increased O&M expenses was not supported, once the adjustment for cyber security standards was made. Mr. Retnanandan submitted that the increased complexity of the system is generally addressed by information technology (IT) initiatives and organizational changes. Mr. Retnanandan did not adjust for any industry productivity gains.

93. The CCA approach included the actual O&M expenses for the base period 2011 to 2013, and estimated O&M levels for the forecast test period taking into consideration all relevant cost

⁶⁶ Exhibit 3539-X0194, CCA argument, page 9, paragraph 24, PDF page 10 of 42.

⁶⁷ Exhibit 3539-X0194, CCA argument, page 1, paragraph 27, PDF page 11 of 42.

⁶⁸ Exhibit 3539-X045, evidence of Raj Retnanandan, paragraphs 44-50. The concerns referred to were referenced in EDTI CCA 2015Feb06-008.

drivers, including growth, inflation, externally imposed costs, one-time costs, and scope changes. Mr. Retnanandan then compared this amount to the forecasts for the test period, adjusted for the impacts of changes to the Alberta Reliability Standards, the completion of the Heartland transmission line, the capitalization of short-term incentive payments and the one-time cost for the cyber security standards.

94. The CCA stated that EDTI did not carry out a detailed forecast of the transmission common costs with input from its distribution function. The CCA submitted that this left a significant gap in the support provided for EDTI common costs using the bottom-up approach and therefore, more weight should be placed on the use of a high level metrics approach to determine the O&M level. Mr. Retnanandan adjusted the numbers filed in his initial evidence based on additional information provided by EDTI in its rebuttal evidence and during the hearing.

95. In its final analysis, provided in reply argument, the CCA proposed reductions to O&M of \$1.1 million in 2015, \$1.14 million in 2016 and \$1.17 million in 2017. Components of the CCA's analysis are presented in the following table:

Table 5. Summary of O&M reductions proposed by the CCA

Table 4-O&M Reduction Based on Metrics Per X0110 as amended per reference in Exhibit 3599-X0187					
		2013	2015	2016	2017
		(%)	(\$ million)		
1	Current year adjusted O&M [line 24; Table 3]		22.42	23.25	23.88
2	Constant \$ O&M levelized for growth [line 26; Table 3]		21.67	21.85	21.95
3	Productivity adjustment (\$20.75m/\$21.82m)		95.1%	95.1%	95.1%
4	Constant \$ O&M levelized for growth adj for productivity		20.60	20.78	20.87
5	Alberta CPI [line 1; Table 3]	129%	134%	137%	139%
6	Composite growth [line 11; Table 3]	114%	113%	114%	114%
7	O&M at current year \$ and growth		21.32	22.11	22.71
8	O&M reduction [line 1-line 7]		1.10	1.14	1.17

Source: Exhibit 3539-X0198, CCA reply argument, page 15, Table 4, PDF page 16 of 28.

96. EDTI submitted in its rebuttal evidence that Mr. Retnanandan's high-level analysis of EDTI's productivity is inherently flawed and fundamentally unreliable⁶⁹ and concluded that there has been an increase, rather than a decrease, in productivity.⁷⁰ EDTI identified five concerns with Mr. Retnanandan's analysis. Two were factual concerns related to the numbers used by Mr. Retnanandan for the STI payments and Heartland adjustments, which were revised by Mr. Retnanandan in his updated analysis, and three were conceptual concerns.

97. EDTI submitted that Mr. Retnanandan had not adjusted for the effect of aging assets on O&M costs, that his composite growth indicator is not a reliable indicator of growth and that Mr. Retnanandan's composite indicator does not include all available relevant growth indicators. EDTI provided an analysis in which it adjusted O&M costs based on the average age of its oil filled pipe type (OFPT) underground transmission cables, its 72-kilovolt (kV) substation power

⁶⁹ Exhibit 3539-X0071, EDTI rebuttal evidence, page 6, A7.

⁷⁰ Exhibit 3539-X0071, EDTI rebuttal evidence, page 19, A15.

transformers and its 72-kV substation equipment, assuming a linear relationship between the age of its assets and an increase in its O&M costs.

98. With respect to the composite growth indicator, EDTI submitted that the size of delivery points may change so that the number of points is not a good indicator, that changes in MWs of power delivered could occur without changes to the size of the system, that transmission lines have different capacities and utilization levels so the length of transmission lines is not a good indicator of system growth and finally, that the size of substations differs so the number of substations is not an accurate indicator of system growth. EDTI concluded that, because each of the growth indicators is misleading or unreliable, an average of the same indicators will also be misleading and unreliable.⁷¹

99. EDTI prepared an analysis of O&M costs, in which O&M costs were adjusted for aging assets, and the composite growth metric was adjusted to include a rate-based metric in constant 2013 dollars but it excluded the substation indicator. EDTI submitted that the substation indicator was redundant given the point of delivery, power transformers and circuit breaker metrics.⁷²

100. EDTI concluded:

EDTI's detailed bottom-up evidence of its budgetary requirements for the Test Period provides substantial and compelling evidence of EDTI's cost of service. The CCA's high level metric approach is, by contrast, based on a composite growth factor, which is problematic for many reasons as discussed above, and has only a theoretical link to EDTI's actual cost of service. As such, any high-level metric cannot substitute or rebut EDTI's detailed bottom-up evidence of its budgetary requirements over the Test Period. In the case of a conflict between the high-level metric approach and EDTI's detailed bottom-up evidence supporting its forecast cost of service, EDTI's evidence is clearly superior and should be preferred.⁷³

101. In testimony Mr. Retnanandan stated that the bottom-up approach used by EDTI and the analysis based on the drivers of cost increases, complement one another. The high level metrics analysis could be used as a reasonability check as well as an O&M cap.⁷⁴

102. In argument, the CCA quoted the witness's testimony that the drivers for cost changes impacting competitive industries have parallels in regulated industries and are relevant if regulation is to serve as a surrogate for competition.⁷⁵

103. In response to questions regarding his growth indicator, Mr. Retnanandan explained that the indicators reflect the geography, number of delivery points and the size of the load served. The number of km of line captures the geographic aspect. Load is more complex, with the number of substations indicative of maintenance, and the size of the substations and the lines

⁷¹ Exhibit 3539-X0071, EDTI rebuttal evidence, pages 10-14.

⁷² Exhibit 3539-X0071, EDTI rebuttal evidence, page 15.

⁷³ Exhibit 3539-X0071, EDTI rebuttal evidence, page 18.

⁷⁴ Exhibit 3539-X0194, CCA argument at page 11, PDF page 12 of 43, citing Transcript, Volume 7, page 1400, line 16.

⁷⁵ Exhibit 3539-X0194, CCA argument, page 12.

indicative of load. The delivery points are also related to substations, as substations could have more than one delivery point.⁷⁶

104. The CCA argued that rate base as an input cost should not be used to measure the performance based on outputs, submitting that FTEs have no relationship to rate base dollars but to other quantitative measures such as the number of km of lines, substations and megawatts of power delivered.⁷⁷

105. In response to EDTI's criticism that the CCA's analysis did not reflect the increasing maintenance due to aging assets, the CCA responded that there are two types of maintenance: capital maintenance and O&M maintenance, which includes both routine maintenance and repairs. FTE growth and related O&M costs are more related to quantitative measures such as km of line rather than the cost of the line in rate base, which includes transmission lines built to different standards such that the addition of dollar costs is not representative of growth. EDTI uses an asset-based management approach based on a health index and condition analysis. This active management results in capital maintenance so that the failure of equipment which normally causes repairs and maintenance to go up may no longer be applicable. The CCA concluded that no further scope change allowance was required to recognize any increase in O&M intensity due to aging assets. Further, any increase in maintenance expense intensity on older assets, in a growing system, is likely counterbalanced by lower O&M on newer plant.⁷⁸

106. EDTI argued that the analysis prepared by Mr. Retnanandan is little more than a very high level indexing of EDTI operating costs, to an inaccurate and incomplete composite growth factor and inflation. Further Mr. Retnanandan provided no analysis that EDTI's operating costs are in fact correlated to his growth and inflation index.⁷⁹

107. EDTI argued that Mr. Retnanandan's analysis "is deeply flawed and unreliable and should not be used as a basis for proposing reductions to revenue requirement."⁸⁰ In EDTI's view, it would be unreasonable to make any adjustments to EDTI's forecast that is justified on a bottom-up basis, based on the analysis of Mr. Retnanandan. In addition, the analysis presented in EDTI's rebuttal evidence, with "corrections" to Mr. Retnanandan's evidence, shows that EDTI's productivity is improving compared to 2011-2013.⁸¹

108. EDTI argued that Mr. Retnanandan was incorrect in saying O&M costs do not increase with age, which can be used as a proxy for condition.⁸² In its reply argument, the CCA provided a graph of maintenance costs, "the bathtub curve," and reiterated its view that the majority of the "wear out failures," which increase with age, are capital maintenance costs not O&M costs.⁸³

109. The CCA noted that EDTI's evidence suggests many of the O&M increases in cost are due to growth and inflation. It argued there is no question that there is a correlation between O&M levels and a high level yardstick based on growth and inflation. However, the question is whether the growth and inflation indicators chosen by the CCA are the most appropriate. The

⁷⁶ Exhibit 3539-X0194, CCA argument, pages 12-13.

⁷⁷ Exhibit 3539-X0194, CCA argument, page 14.

⁷⁸ Exhibit 3539-X0194 CCA argument, pages 14-16.

⁷⁹ Exhibit 3539-X0193, EDTI argument, page 72, paragraph 186.

⁸⁰ Exhibit 3539-X0193, EDTI argument, page 72, paragraph 186.

⁸¹ Exhibit 3539-X0193, EDTI argument, page 72, paragraphs 189-191.

⁸² Exhibit 3539-X0193, EDTI argument, pages 81-82.

⁸³ Exhibit 3539-X0198, CCA reply argument, pages 11-13, PDF pages 12-14 of 28.

CCA submitted its growth indicators are appropriate and reasonable. For the purpose of an accountability mechanism, the proposed growth and inflation indicators, should be relevant and show a level of stability over the period under examination.⁸⁴

110. EDTI reiterated its view that the number of substations is a redundant indicator because, for every substation, there will be an increase in one or more of points of delivery, power transformers and circuit breakers and, including points of delivery, power transformers and circuit breakers underestimates the growth normalization results. EDTI expressed concern that Mr. Retnanandan picked growth indicators that showed small increases and did not explain why he excluded the growth indicators raised by the AUC and provided in EDTI-AUC-2015FEB06-065 Attachment 1, Table 8, which included the number of energized sites, km of transmission conductor, number of power transformers, number of HV circuit breakers and the transmission total rate base.⁸⁵

111. The CCA argued that its growth indicators are suitable for an urban TFO and that the customer numbers proposed by EDTI are only relevant for distribution utilities. The CCA stated that the growth of a system is a function of the physical size and characteristics of the system, not the dollars invested.

Commission findings

112. The Commission has reviewed the detailed submissions from the CCA and EDTI on the use of the O&M high level metrics methodology proposed by the CCA.

113. The bottom-up approach used by EDTI is a reasonable approach. However, the Commission agrees with Mr. Retnanandan that the bottom-up approach used by EDTI and a high level methodology such as that proposed by the CCA may complement one another and that some form of high level metrics could be used as a reasonableness check on forecast O&M costs.

114. It is difficult for the Commission to test the reasonableness of EDTI's O&M forecast because not all of its assumptions and their relationships have been provided, although the Commission acknowledges that it may not be practical to do so.

115. The high level analysis proposed by the CCA has not previously been approved by the Commission. A controversial component of the CCA analysis is the determination of the composite growth indicator. EDTI also challenged the CCA for its failure to adjust for the effect of aging assets and submitted that Mr. Retnanandan provided no analysis that EDTI's operating costs are in fact correlated to his proposed growth and inflation index.⁸⁶

116. With respect to EDTI's proposed adjustment to the CCA analysis for aging assets, the adjustment is based on an assumption of a linear relationship between O&M costs and the age of EDTI's assets, and is based on three classifications of assets.⁸⁷ However, EDTI provided no regression analysis in support of the assumption of a linear relationship between the age of assets and O&M costs. Likewise, the CCA argument that the greater intensity of O&M costs on older assets is offset by less O&M on newer assets, although intuitively appealing, was not supported by empirical evidence.

⁸⁴ Exhibit 3539-X0198, CCA reply argument, paragraphs 25-27, PDF pages 9-10 of 28.

⁸⁵ Exhibit 3539-X0193, EDTI argument, pages 83-84.

⁸⁶ Exhibit 3539-X0193, EDTI argument, page 72, paragraph 186.

⁸⁷ Exhibit 3539-X0071, EDTI rebuttal evidence, pages 10 to 12.

117. The Commission has insufficient evidence to conclude the CCA's high level metrics analysis is sufficiently reliable to adjust the revenue requirement for O&M costs.

118. Nonetheless, the Commission considers further exploration of the composite growth indicator proposed by the CCA, such as adding or removing components, introducing weightings to the components, or testing for possible lagged impacts of changes to variables, would be valuable.

7.3 Labour related costs

119. Labour related costs are classified as labour, overtime, and fringe and burden. As a complement to its own labour force, EDTI engages contractor services. In the sections that follow, the Commission will consider EDTI's labour-related forecast costs. The Commission has not included an analysis related to fringe and burden, which was explored during the proceeding. EDTI had confirmed in response to EDTI-AUC-2015FEB06-122 that it would adjust the fringe benefit rate and transfer burden for 2015 and 2016, in the compliance filing to this decision, to reflect the new information that there will be no increase in 2015 and 2016 to the Local Authorities Pension Plan percentage of base salaries.

7.3.1 FTE forecasts

120. For its 2015 test year, EDTI has applied for a total of 168.2 operating and capital FTEs; representing an increase of 6.5 FTEs over the number approved for 2014, in Decision 2014-269. For the 2016 test year, EDTI has forecast a decrease of 0.1 FTEs, followed by a forecast increase of 1.1 FTEs for 2017.

121. EDTI submitted that the forecast FTE increases are required:⁸⁸

- mainly due to higher forecast workload from increased capital activity, to address ongoing growth of the transmission system, and due to increased operating activity
- and due to the addition of an engineer-in-training for succession planning

122. Table 6 displays total actual transmission FTEs from 2009-2014, and the corresponding forecast FTE levels from 2015-2017:

Table 6. Transmission FTE trend – 2009-2014 actual, with 2015-2017 forecasts

	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual	2014 actual	2015 forecast*	2016 forecast*	2017 forecast*
Operating	76.3	79.6	68.0	63.2	72.6	79.3	82.6	83.2	82.3
Capital	51.3	55.4	69.8	89.1	88.7	84.5	85.6	84.9	86.9
Total actual or forecast	127.6	135.0	137.8	152.3	161.3	163.8	168.2	168.1	169.2
Trend increase		7.4	2.8	14.5	9.0	2.5	4.4	(0.1)	1.1
Trend % increase		5.8%	2.1%	10.5%	5.9%	1.5%	2.7%	(0.1%)	0.7%
Total decision	124.0	137.8	134.3	152.3	156.3	161.7			

* The method for calculating FTES was changed in 2015. In its application at paragraph EDTI indicated that the change resulted in a decrease of 4.1 FTEs in 2015.

Source: Extracted from Decision 2012-272, Table 4, page 11; and Exhibit 3539-X0193, EDTI argument, Table 1, page 14 (2012D and 2012A (column A and column B): Table 1.4.1-1 in 2013-2014 TFO Application; 2013D and 2013A (column C and column D): Table 1.4.1-1 in 2015-

⁸⁸ Exhibit 0003.00.EDTI-3539, application, page 61, paragraphs 171-172.

2017 TFO Application and MFR Schedule 5.5, Exhibit 3539-X0087; 2014D, (column E): Table 1.4.1-2 in 2015-2017 TFO Application and MFR Schedule 5.5, Exhibit 3539-X0087; 2014A (column F): MFR Schedule 5.5, Exhibit 3539-X0087; 2015F, 2016F, 2017F (column G, column H, column I): Table 1.4.1-2 in 2015-2017 TFO Application and MFR Schedule 5.5, Exhibit 3539-X0087.

123. The FTE numbers shown in 2015-2017 were calculated using a new methodology. EDTI explained that the 2015 forecast number decreased by 4.1 FTEs as a result of the change in methodology,⁸⁹ comprised of an O&M and a capital reduction of 1.3 FTEs and 2.8 FTEs respectively.⁹⁰

124. The 2014 decision approved number of total FTEs was 161.7. Given the change in methodology, the Commission has restated the 2015 number. Assuming the new methodology, the number of 2015 FTEs will increase by 4.1, which results in a restated number of 172.3, thereby making it comparable to the 2014 number. This results in a difference of 10.6 FTEs between the 2014 decision amount and the restated 2015 total FTE forecast. Comparison of the adjusted 2015 forecast FTEs to the actual 2014 FTEs shows an increase of 8.5 FTEs. The number of FTEs in 2016 and 2017 were prepared using the same methodology as in 2015 and remains essentially the same as the number of FTE's in 2015.

125. Table 7 below provides the historical and forecast increases in EDTI's transmission system growth indicators:

Table 7. Transmission system growth indicators 2009-2013 actual with 2014-2017 forecasts

	2009 actual	2010 actual	2011 Actual	2012 actual	2013 actual	2014 UF	2015 forecast	2016 forecast	2017 forecast
Number of energized sites (#)	332,583	337,885	343,415	350,368	359,195	368,428	376,918	388,733	399,346
Km of transmission conductor (#)	195	195	203	203	257	257	257	260	260
Number of power transformers (#)	58	60	62	62	62	62	62	62	62
Number of high voltage circuit breakers (#)	141	145	149	149	149	149	149	151	155
Transmission total rate base (\$ million)	282	296	314	332	471	627	663	692	728
MW power delivered	1281.7	1213.6	1196.9	1287.8	1359.0	1323.8	1342.0	1359.0	1375.0
No. of substations	29	30	30	31	30	30	30	30	30

Source: Exhibit 3539-X0009, information response EDTI-AUC-2015FEB06-065 Attachment 1, and EDTI-CCA 2015FEB06-008.

⁸⁹ Exhibit 0003.00.EDTI-3539, application, paragraph 171, PDF page 74.

⁹⁰ Exhibit 3539-X0005, IR responses, EDTI-AUC-2015FEB06-105.

126. Table 8, prepared by EDTI⁹¹ is reproduced below.

Table 8. Transmission capital expenditures and capital FTEs trend 2009-2017

	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual	2014 decision	2015 forecast	2016 forecast	2017 forecast
	(\$ million)								
Capital expenditures	31.8	35.0	58.6	101.0	173.4	41.4	43.8	70.1	47.8
Less: Heartland project	7.5	5.3	28.1	67.0	143.0	0.0	0.0	0.0	0.0
Add: customer contributions	8.2	15.5	22.7	5.8	(2.1)	0.3	0.6	16.3	11.4
Adjusted transmission capital expenditures	32.5	45.2	53.2	39.8	28.3	41.7	44.4	86.4	59.2
Less: contractor capital costs				18.2	9.3	21.5	19.9	61.0	34.3
Transmission capital expenditures net of contractor costs				21.6	19.0	20.2	24.5	25.4	24.9
Capital FTEs (#)	51.3	55.4	69.8	89.1	88.7	85.9	85.6	84.9	86.9

Source: Exhibit 3539-X0009, information response EDTI-AUC-2015FEB06-065 Attachment 1.

127. Table 8 compares capital FTEs to adjusted capital expenditures. For comparative purposes, the capital expenditures related to the Heartland project were removed, and customer contributions were added, because these contributions reduced the net capital expenditures of EDTI. As work for capital expenditures may be contracted, the amounts paid to capital contractors have also been subtracted from transmission capital expenditures, commencing with the year 2012. The remaining balance of transmission capital expenditures, net of contractor costs, reflects capital projects undertaken by EDTI employees, including supervision of contractors.

128. Table 8 shows that the adjusted transmission capital expenditures, net of forecast contractor costs, are forecast to remain fairly level in the test years, at approximately the \$25 million level and the number of capital FTEs are forecast to remain relatively stable at 85 to 87 FTEs.

129. EDTI's FTE forecast included succession planning forecast FTEs for the categories of engineer-in-training, power electrician apprentice, and cableman apprentice, as shown in Table 9 below:

Table 9. EDTI succession planning FTEs 2012-2017

	A 2012 A	B 2013 D	C 2013 A	D 2014 D	E 2015 F	F 2016 F	G 2017 F
Salary							
1 Engineers in training	-	1.2	1.9	1.3	2.0	2.0	2.0
Labour							
2 Power electrician apprentices	3.3	2.0	2.3	2.0	2.0	-	-
3 Cableman apprentices	<u>1.1</u>	<u>2.0</u>	<u>2.1</u>	<u>2.0</u>	<u>2.0</u>	<u>2.0</u>	<u>3.0</u>
4 Total apprentices	4.4	4.0	4.4	4.0	4.0	2.0	3.0

Source: Exhibit 0003.00.EDTI-3539, application, Table 1.4-1, page 51.

⁹¹ Exhibit 3539-X0005, IR responses, EDTI-AUC-2015FEB06-065, Attachment 1.

130. EDTI explained that the engineer-in-training program is three years in length and the apprentice programs are four years in length.

131. The UCA stated that it was not proposing any adjustment to the number of succession planning FTEs proposed by EDTI. However, the UCA requested that EDTI be directed to provide an analysis, as part of future applications to test these forecasts because they identify new entry level FTEs in each of the last five years, along with the number of employees that have retired by year by position. Further, the UCA recommended that EDTI be directed to include a table, such as Table 5.0-1 of the EDTI rebuttal evidence,⁹² as part of the future tariff applications.

132. EDTI responded that it had already provided the requested information for this proceeding and that it intends to do so in future applications. Therefore, a further direction as sought by the UCA is not required.

Commission findings

133. The Commission has grouped the operating and capital FTEs to assess EDTI's explanation that the increase in FTEs was due to greater capital and operating activity. Table 10 below shows the transmission FTEs, grouped by actual and approved capital and operating FTEs for each year:

Table 10. Transmission FTEs by category 2007-2014

	2007	2008	2009	2010	2011	2012	2013	2014
Operating – approved	77.6	78.9	78.4	87.8	70.4	66.5	70.4	75.8
Operating – actual	70.8	77.4	76.3	79.6	68.0	63.2	72.6	79.3
Total operating over (under) #	(6.8)	(1.5)	(2.1)	(8.2)	(2.4)	(3.3)	2.2	3.5
Total operating over (under) %	(8.8%)	(1.9%)	(2.7%)	(9.3%)	(3.4%)	(5.0%)	3.1%	4.6%
Capital – approved	60.4	56.3	45.6	50.0	63.7	85.9	85.9	85.9
Capital – actual	56.3	47.6	51.3	55.4	69.8	89.1	88.7	84.5
Total capital over (under) #	(4.1)	(8.7)	5.7	5.4	6.1	3.2	2.8	(1.4)
Total capital over (under) %	(6.8%)	(15.5%)	12.5%	10.8%	9.6%	3.7%	3.3%	(1.6%)

Source: Extracted from Decision 2012-272, Table 4, page 11 and Table 11, page 14; and Exhibit 3539-X0193 EDTI argument, Table 1, page 14 (2012D and 2012A (column A and column B): Table 1.4.1-1 in 2013-2014 TFO Application; 2013D and 2013A (column C and column D): Table 1.4.1-1 in 2015-2017 TFO Application and MFR Schedule 5.5, Exhibit 3539-X0087; 2014D, (column E): Table 1.4.1-2 in 2015-2017 TFO Application and MFR Schedule 5.5, Exhibit 3539-X0087; 2014A (column F): MFR Schedule 5.5, Exhibit 3539-X0087; 2015F, 2016F, 2017F (column G, column H, column I): Table 1.4.1-2 in 2015-2017 TFO Application and MFR Schedule 5.5, Exhibit 3539-X0087.

134. EDTI indicated that the increase in FTEs is mainly due to higher forecast workload due to increased capital activity required to address ongoing growth of the transmission system, increased operating activity and the addition of an engineer-in-training for succession planning. The Commission will examine the increases in capital FTEs relative to capital activity and operating FTEs relative to the growth of the transmission system.

135. No specific physical measure of capital activity was provided on the record of the proceeding. The Commission will consider capital expenditures excluding the Heartland project and work done by contractors, as a proxy for the level of capital activity. In Table 8 in the background section above, the 2014 decision amount for capital expenditures, net of contractor

⁹² Exhibit 3539-X0071, EDTI rebuttal evidence, Table 5.0-1, Succession Planning FTEs, PDF page 41 of 82.

costs, was \$20.2 million. The adjusted forecast capital expenditures, net of contractor costs, for the 2015-2017 period are \$24.5, \$25.4 and \$24.9 million, respectively. Table 8 shows that the forecast transmission capital expenditures net of contractor costs for the test period are relatively constant, having increased slightly over 2012 and 2013 amounts.

136. EDTI is forecasting capital FTEs of 85.6 in 2015, 84.9 in 2016 and 86.9 in 2017, as shown in Table 8 above. The Commission has restated the 2015 FTE number by increasing this number by 4.1 FTEs, which results in a restated number of 172.3. Of this increase, 2.8 FTEs relate to capital. When adjusted for the change in methodology, the forecast FTEs in the test period have increased from 2014 actuals of 84.5 FTEs.

137. Considering the change in methodology for calculating FTEs and the information provided in the above tables, the forecast capital FTEs appear reasonable and the Commission accepts EDTI's forecast FTE numbers for the test period. Accordingly, the Commission finds that the proposed capital FTE levels in the test years are reasonable.

138. With respect to forecast operating FTEs, EDTI justified its increase on the basis of increased operating activity, which it appears to be attributing to system growth. Table 7 above presents a number of metrics that may be considered in assessing system growth. The data indicates that system growth occurred from 2011 to 2013, with little additional growth occurring again until the 2017 forecast period. None of the indicators individually indicate a significant level of growth during the test period.

139. Table 10 shows that actual operating FTEs were higher than the approved level in the last two years.

140. In Decision 2014-269, the Commission approved 70.4 operating FTEs for 2013 and 75.8 operating FTEs for 2014. The forecast operating FTEs provided in Table 6 above are 82.6, 83.2 and 82.3 for 2015, 2016 and 2017, respectively. Because the forecasts for 2015-2017 are based on the new FTE methodology, the historical numbers are not directly comparable. The application of the new methodology for the 2015 forecast resulted in a reduction of 4.1 FTEs, comprising a reduction of 1.3 for operating FTEs and a reduction of 2.8 for capital FTEs. To assist with comparability, given the change in FTE calculation methodology, the Commission restated the historical operating FTEs by decreasing the number of FTEs by 1.3 (assuming a difference of 1.3 FTEs) for each of 2013 and 2014. The restated operating FTEs for 2013 and 2014 are 71.3 and 78.0 respectively.

141. Given the relative stability of the transmission system growth indicators shown in Table 7 above, the Commission is not persuaded that EDTI requires the proposed increase in operating FTEs over the actual 2014 operating FTEs of 79.3, or the approved 2014 operating FTEs of 75.8, which as restated, are 78.0 and 74.5, respectively. The Commission further notes that in 2013, EDTI had 72.6 actual operating FTEs, restated as 71.3 FTEs, and is forecasting approximately 83 FTEs over the test period, based on the new methodology, to operate a system of similar size.

142. In addition, the Commission considers that EDTI regularly undertakes performance improvement projects to improve functionality, enhance performance, or allow service to be

provided at a lower cost.⁹³ In Decision 2014-269, the Commission noted in Table 33 at paragraph 381, that \$9.3 million had been spent on performance improvement projects from 2010 to 2012.

143. EDTI is continuing its performance improvement program in the test period. In Section 10.2 of this decision, Table 31 provides a comparison of historical actual and approved performance improvement capital additions. The historical capital additions for performance improvements were \$4.6 million in 2013 and \$0.17 million in 2014. The amounts forecast for the test years are \$5.76 million, \$0.44 million and \$0.18 million, respectively. The Commission expects that the investment in performance improvement projects would reduce operating and maintenance requirements and costs.

144. Finally, the Commission acknowledges the 0.7 increase in FTEs due to the engineers-in-training program, which is part of the succession plan. The Commission has reviewed the table provided in EDTI's application, which shows the program will have two engineers-in-training throughout the forecast period.

145. In light of the preceding analysis regarding the relatively constant size of EDTI's system and the historical expenditures on performance improvement projects, the Commission finds that the forecast operating FTE additions for the test period have not been adequately supported. Accordingly, the Commission directs EDTI to reduce the forecast operating FTEs for each of the test years by 2.0 FTEs.

146. EDTI is directed to use an average cost per FTE of \$130,000 for 2015 and \$140,000⁹⁴ for 2016 and 2017, which results in FTE-related operating cost reductions of \$260,000 for 2015 and \$280,000 for each of 2016 and 2017. EDTI is further directed not to substitute contractor resources or increased overtime for the directed FTE reductions made for the test years, for the purposes of calculating its revenue requirement for the test years, in its compliance filing. EDTI is also directed to provide a schedule identifying where the directed FTE adjustments have been made in the compliance filing.

147. In response to the UCA request for a direction for a succession planning analysis, requesting a table such as Table 5.0-1 in future tariff applications, the Commission observes that a similar table with the requested information was provided by EDTI in the application as Table 1.4-1, which is reproduced in Table 9 above. Because EDTI has responded that it intends to provide the requested information as part of its future GTAs, the Commission finds that no direction on this matter is required.

7.3.2 Vacancy forecasts

148. The vacancy rate represents a ratio of the actual number of vacant FTE positions compared to the total approved FTE positions for a given period, and is used to reduce the forecast labour costs to reflect that a certain number of positions will be vacant in the forecast period. The result is generally a reduction in the forecast labour costs.

149. In the application, EDTI applied a zero per cent vacancy rate for its salaried employees.⁹⁵ For its salaried staff, EDTI submitted that it had calculated a two-year average gross vacancy factor, which resulted in a negative 2.9 per cent vacancy factor forecast. Consistent with the

⁹³ Decision 2014-269, paragraph 351, page 74.

⁹⁴ Exhibit 0003.00.EDTI-3539, application, Table 1.4.3-2, PDF page 84.

⁹⁵ Exhibit 0003.00.EDTI-3539, application, page 69, paragraph 188.

Commission's previous determination in Decision 2012-272 that use of a negative vacancy factor provides more than 100 per cent of salary, EDTI forecast a zero per cent vacancy factor for salaried employees for the test years. EDTI confirmed that it had tracked and adjusted for new FTE positions that were hired, as part of the vacancy factor calculations.

150. For labour staff, EDTI stated that it did not apply a vacancy rate because it forecast its labour requirements based on its forecast operating and capital work requirements. EDTI submitted that if a particular labour employee is unable to perform their function for a period of time, due to sickness or leaving employment with EDTI, then the position is backfilled to ensure that the work levels are maintained.⁹⁶

151. Mr. Bell, for the UCA, expressed concern over EDTI's frequent use of vacancies to explain variances for 2012 and 2013.⁹⁷ After reviewing the variance explanations provided by EDTI "...for both 2012 and 2013, there is a pattern of variance explanations attributed to underspending related to vacancies. There is little or no indication of variances related to increased overtime or use of contractors to offset the variance. In addition, there are no variances in 2012 or 2013 related to negative vacancies."⁹⁸ Mr. Bell submitted that EDTI had used favourable vacancy variances as explanations for comparisons of actual and approved costs for 2012 and 2013 of \$1.15 million and \$1.31 million, respectively. Considering these amounts, Mr. Bell recommended a reduction to O&M of \$1.20 million for each of the test years. Following an update of Mr. Bell's analysis, based on EDTI rebuttal evidence that only part of the costs initially identified was allocated to EDTI, the vacancy savings were reduced to \$0.46 million and \$0.40 for 2012 and 2013, respectively. Based on his updated analysis, Mr. Bell's recommendation for an O&M reduction for each test year was lowered to \$0.43 million.

152. EDTI submitted that Mr. Bell's recommendation to reduce the operating FTE forecast was flawed and inaccurate. EDTI cited several reasons why it disagreed with Mr. Bell's approach, including that he does not make a distinction between labour and salary vacancies, his recommendation is inconsistent with previous Commission and EUB decisions with respect to performing vacancy rate calculations, and EDTI's application makes it clear that salary and labour costs saved by a reduction in FTEs were more than offset by other salary and labour, contractor and overtime costs. EDTI responded that a reduction for vacancies, as proposed by the UCA, should not be applied because the evidence,⁹⁹ as shown in the table below, confirms staffing costs have been higher than approved on an actual basis and the proposed salaried and labour employee vacancy rates are consistent with prior years and previous Commission directions:

⁹⁶ Exhibit 0003.00.EDTI-3539, application, page 68, paragraph 185.

⁹⁷ Exhibit 3539-X0192, UCA argument, page 8, paragraphs 25-27.

⁹⁸ Exhibit 3539-X0051, UCA evidence, pages 2-4.

⁹⁹ Exhibit 3539-X0071, EDTI rebuttal evidence, Table 3.0-3 2012-2017 Staffing Cost Summary, PDF page 28.

Table 11. EDTI staffing cost summary 2012-2017

Union and non-union salary and labour		A 2012 D	B 2012 A	C 2013 D	D 2013 A	E 2015 F	F 2016 F	G 2017 F
		(\$ million)						
1	Total regular – operating and capital	13.37	12.87	14.60	14.50	16.85	17.55	18.28
2	Total fringe + burden – operating and capital	3.14	5.01	5.98	5.71	7.38	7.91	8.69
3	Overtime							
4	Overtime – operating		0.57	0.46	0.76	0.60	0.62	0.64
5	Overtime – capital		1.12	0.62	1.08	0.86	0.65	0.76
6	Total overtime – operating and capital	1.12	1.69	1.07	1.83	1.45	1.27	1.40
7	Total	17.64	17.74	19.53	20.04	23.26	24.18	25.53
8	Variance		0.10		0.51			

Source: Exhibit 3539-X0071, EDTI rebuttal evidence, Table 3.0-3, 2012-2017 Staffing Cost Summary, PDF page 28.

153. In response to EDTI's assertion that actual staffing costs are higher than forecast on an overall basis, primarily due to increased overtime, Mr. Bell explained that his analysis does not show material offsetting variances related to increased overtime. For this reason, the UCA recommended a \$0.43 million reduction per year as a calculated vacancy reduction amount.¹⁰⁰

Commission findings

154. Decision 2012-272 stated:¹⁰¹

78. To address the subjective nature of approximating “net” vacancy rates, and in consideration of the inability to differentiate backfill information between vacancy related backfills and higher forecast workload, the Commission finds that gross vacancy rates shall be used instead. Gross vacancy rates can be calculated for historical comparison, as shown in tables 13 and 14, and comparison between approved FTEs and actual FTEs then becomes a straightforward calculation. The Commission notes that the existing vacancy calculation does not take into account the number of actual new positions hired during the period, which were not part of the approved forecast FTE level, and that this has the effect of understating the actual vacancy rate.

...

80. ... For transmission, EDTI is directed to track monthly data on each FTE category as shown in Table 14 above, and to provide this information as part of future filings. EDTI is also directed to track new positions that are hired but were not part of the approved FTE level and to reflect these in the vacancy calculations....

155. In the application, EDTI confirmed that it had followed the Commission's direction from Decision 2012-272 to use gross vacancy factors and that it had tracked and adjusted for new FTE positions that were hired, as part of the vacancy factor calculations. EDTI indicated that it had done this for 2012 and 2013 but not 2011, based on the timing of the decision, and it had based its vacancy calculation on a two-year average instead of a three-year average.

¹⁰⁰ Exhibit 3539-X0192, UCA argument, page 9, paragraphs 29-30.

¹⁰¹ Decision 2012-272, page 21, paragraphs 78 and 80.

156. The Commission observes that EDTI's application used a two-year average, which incorporated the additional information for 2012 and 2013, as directed in Decision 2012-272, for positions that were hired but not included as part of the approved FTE level.

157. The Commission finds that due to the negative average vacancy factor forecast for salary FTEs, no vacancy factor is warranted for salary FTEs for the test years. With regard to the labour FTEs, and after considering the relatively small vacancy factor, the Commission will accept EDTI's use of a zero vacancy factor for labour FTEs.

158. For the above reasons, the Commission finds that a zero vacancy factor shall continue to be used for both salary and labour FTEs for the test years.

159. Nonetheless, the Commission considers that EDTI has interpreted its direction from Decision 2012-272 in a manner other than it had intended. The Commission considers that vacancies do occur. EDTI's explanation that positive vacancy related variances are offset by higher staffing costs, overtime and use of contractors has not been adequately supported.

160. Given the apparent ambiguity of the direction, the Commission has for the purpose of determining the revenue requirement for the test period, accepted EDTI's proposed use of zero vacancy rates for both salary and labour employees.

161. The Commission directs EDTI in its next application to disregard Direction 6 provided in Decision 2012-272 with respect to the calculation of vacancy rates.

162. The Commission further directs EDTI to provide an analysis of vacancies and to explain the rationale for its calculations, with specific reference to the treatment of new positions, transfers and "backfilling." The Commission does not understand how, if new positions are properly reflected in the vacancy calculation, it would be possible to have a negative vacancy rate.

163. With regard to the UCA proposal for a reduction to revenue requirement to reflect a variance explanation based on vacancies, the Commission considers that such ad hoc adjustments are not sufficiently supported. For this reason, the Commission rejects the UCA proposal.

7.3.3 Account 560 (O&M supervision and engineering)

164. EDTI's forecast of O&M supervision and engineering costs include the following categories:

- transmission substation engineering, system planning and asset management
- management and supervision of transmission substation operations and substation field operations non-wrench time
- transmission line and cable operations supervision and engineering
- operation and maintenance supervision and engineering – master overhead pool (MOP)
- transmission planning and scheduling

165. EDTI's forecast O&M supervision and engineering costs are summarized in the table below:

Table 12. O&M supervision and engineering costs 2012–2017

Sec			A 2012 A	B 2013 D	C 2013 A	D 2014 D	E 2014 UF	F 2015 F	G 2016 F	H 2017 F
			(\$ million)							
1	4.1.1	Transmission substation engineering, system planning and asset management Transmission substation	2.15	2.41	2.56	2.70	3.09	3.58	4.00	4.13
2	4.1.2	Operations supervision and non-wrench time transmission line and cable	1.06	1.40	1.43	1.57	1.49	1.49	1.57	1.34
3	4.1.3	Operations supervision and engineering operation and maintenance	0.90	0.94	0.96	1.01	1.02	1.07	1.07	1.21
4	4.1.4	Supervision and engineering – MOP	0.68	0.82	0.76	0.91	0.93	0.70	0.73	0.77
5	4.15	Transmission project delivery office	-	-	-	-	-	0.34	0.36	0.37
6	Total costs		4.79	5.57	5.71	6.19	6.55	7.18	7.73	7.81
7	Variance				0.14		0.37	0.63	0.55	0.08

Source: Exhibit 0003.00.EDTI-3539, application, Table 4.1-1 Operation and Maintenance Supervision and Engineering 2012-2017, page 257.

166. Mr. Bell, on behalf of the UCA, expressed concern over the rising level of supervision costs being forecast in Account 560, while the CCA expressed concern with the decreasing portion of these costs being allocated to capital.

167. The ratio of supervision and engineering costs to other transmission operating costs, as calculated by Mr. Bell, was an average of 58.31 per cent for 2012-2014, and 61.11 per cent for 2015, 70.84 per cent for 2016, and 70.11 per cent for 2017.¹⁰² Mr. Bell quoted the description of Account 560 in the USA:

This account shall include the cost of labour and expenses incurred in the general supervision and direction of the operation and maintenance of the transmission system as a whole. (Example Activities are outlined in accounts 561, 562, 563, 564, 566). Direct supervision of the same shall be charged to the appropriate account. (See Operating Expense Instruction I).¹⁰³

168. Based on an EDTI undertaking¹⁰⁴ Table 13 below excludes costs in Account 560 not directly related to O&M, and calculates the ratio of Account 560 to other Transmission operating costs. This resulted in a ratio of actual costs in Account 560 to other transmission operating costs of 39 per cent for 2012-2014. For the 2015-2017 forecasts, the ratio is 39 per cent, 44 per cent, and 42 per cent, respectively.

¹⁰² Exhibit 3539-X0192, UCA argument, page 9, paragraph 31.

¹⁰³ Exhibit 3539-X0192, UCA argument, page 9, paragraph 32, quoting *Uniform System of Accounts Prescribed for Public Utilities and Licensees*, AUC, page 64.

¹⁰⁴ Exhibit 3539-X0126, undertaking by Mr. Wiles to Mr. Marriott, Transcript, Volume 1, page 169.

Table 13. Ratio of O&M supervision and engineering costs to other transmission operating costs

	A 2012 A	B 2013 A	C 2014 UF	D 2014 A	E 2015 F	F 2016 F	G 2017 F
1 O&M supervision and engineering (560) related to O&M in other transmission operating cost accounts ¹	3.39	3.84	4.26	4.13	4.70	5.05	5.00
2 Errors and omissions	-	-	0.08	-	0.16	0.16	0.16
3 O&M supervision and engineering (560) not related to O&M in other transmission operating cost accounts	1.39	1.88	2.30	2.05	2.48	2.68	2.81
4 Total O&M supervision and engineering (560) (row 1 + row 3)	4.79	5.71	6.55	6.18	7.18	7.73	7.81
5 Other transmission operating costs	8.61	9.76	10.18	10.61	11.75	11.01	11.39
6 Ratio (row 1 – row 2) / row 5	39%	39%	41%	39%	39%	44%	42%

¹EDTI notes that row 1 includes non-wrench costs and management costs related to capital projects which are not related to the other transmission operating cost accounts. It would take considerable time and effort to attempt to split these costs out of Account 560. Source: Exhibit 3539-X0126, undertaking by Mr. Wiles to Mr. Marriott, Transcript, Volume 1, page 169.

169. In rebuttal evidence, EDTI clarified that Account 560 includes not only supervision of staff that work on O&M projects and the engineering of O&M projects, included in other transmission operating cost accounts, but also work that is not related to other transmission operating cost accounts. In addition, some areas of other transmission operating cost work do not have corresponding increases in Account 560.¹⁰⁵

170. The UCA responded to the updated information in EDTI's rebuttal evidence and undertaking in argument, noting that the new information provided a new concern, as there is an unexplained rise in O&M supervision and engineering costs that are unrelated to O&M in other transmission operating accounts from \$1.39 million in 2012 to forecasts of \$2.48 million, \$2.68 million and \$2.81 million through the test years 2015-2017. The UCA questioned whether these costs should be included in Account 560 and submitted that, if the accounting practice was to continue, EDTI should be directed to separately identify, as part of the initial filing of future applications, the costs included in Account 560 that are unrelated to O&M in other transmission operating accounts, so that these costs can be properly examined and tested.

171. The UCA recommended that the 39 per cent ratio should be applied to the forecast 2016 and 2017 total of O&M supervision and engineering related to O&M in other transmission operating accounts. Applying the 39 per cent ratio, combined with the identified errors and omissions adjustment, the UCA calculated that the reductions to the forecasts should be \$0.6 million in 2016 and \$0.4 million in 2017, respectively.¹⁰⁶

172. In argument, EDTI stated that Mr. Bell's analysis is fundamentally flawed because it is premised on a misunderstanding of the costs in EDTI's account and correlations that do not exist. In support of this position, EDTI referred extensively to its rebuttal evidence, including the following response to Mr. Bell on the lack of the relationship between O&M in Account 560 and other transmission operating cost accounts:

[A32] ... Mr. Bell's statements that "[t]he simple fact that there is less capital should not result in an increase in O&M" and that "[t]he reduced workload should be managed through attrition and the succession planning so that there is no increased

¹⁰⁵ Exhibit 3539-X0071, EDTI rebuttal evidence, page 31, A31.

¹⁰⁶ Exhibit 3539-X0192, UCA argument, page 10, paragraph 39.

allocation to operations” are misleading. EDTI’s staffing levels are determined with a view to ensuring that EDTI has the correct mix and level of internal resources to complete its normal core level of anticipated work, as determined by EDTI’s detailed bottom-up budgeting approach and reflecting historical actual amounts of work completed in previous years. EDTI will add or remove a position based on its capital and operating work load over the long term. That is, EDTI will not add or remove positions if it expects a short term spike or decline in its work load. As a result, all other things being equal, the level of capital activity in a given year will inversely affect operating costs in Account 560 over the short term.¹⁰⁷

173. EDTI summarized in its rebuttal evidence and final argument why there is no relationship between the costs in Account 560 and the O&M in all of the other operating cost categories. First, Account 560 contains direct costs that are not related to the O&M in other transmission operating accounts. Second, the O&M in other transmission operating accounts includes costs that are not related to the O&M costs in Account 560. Third, as noted above, the costs in Account 560 will fluctuate depending on the amount of capital work completed year to year, whereas the costs included in the other transmission operating accounts will not.¹⁰⁸

174. The UCA replied that it is clear from EDTI’s rebuttal evidence that Account 560 includes costs for O&M supervision and engineering not related to O&M in other transmission operating cost accounts. The UCA submitted that EDTI is not following the USA definition for Account 560.¹⁰⁹

175. The CCA submitted that staff additions to Account 560 have resulted in a loss of productivity. The amount of indirect labour capitalized, primarily from Account 560, has decreased. In 2012, capital labour as a percentage of total labour was 46.2 per cent, for 2013 it was 42.3 per cent. It dropped to 39.3 per cent in 2014 and then again to 39.1 per cent for 2015. In 2016, the ratio is forecast to be 37.3 per cent followed by 40.8 per cent in 2017.¹¹⁰

176. The CCA stated that “EDTI has not supported why the percentage of indirect labour considered as O&M related, during the 2012 to 2014 period should be different from that for the 2015-2017 period on average.”¹¹¹ The CCA submitted that EDTI had not explained why an increased allocation of hours from existing and new FTEs to O&M functions is required to support increased O&M activity relative to capital activity levels.

177. The CCA recommended that the proportion of indirect labour for O&M for the test years should be consistent with the percentage of indirect labour considered as O&M for the 2012-2014 period on average, after adjustments are made to reflect the 100 per cent O&M nature of two SCADA FTEs added in 2013 and one in 2014.

178. The CCA submitted that EDTI should be directed to adjust its indirect O&M labour accordingly and make the corresponding adjustments to the MOP amounts allocated to O&M and capital.

¹⁰⁷ Exhibit 3539-X0193, EDTI argument, page 90, paragraph 221.

¹⁰⁸ Exhibit 3539-X0197, EDTI reply argument, paragraph 71.

¹⁰⁹ Exhibit 3539-X0196, UCA reply argument, paragraph 29.

¹¹⁰ Exhibit 3539-X0194, CCA argument, page 18, paragraph 50.

¹¹¹ Exhibit 3539-X0194, CCA argument, page 19, paragraph 52.

179. EDTI challenged the CCA's recommendation as based on errors and the mixing of unrelated concepts. EDTI submitted in rebuttal evidence that the non-wrench times related to the specialist project engineer is an O&M cost, that the facility application analyst would work on compliance with Alberta Reliability Standards is an O&M cost; and that the SCADA technologists were hired in 2013 to develop and implement required cyber security process changes is an O&M cost. EDTI submitted that the CCA's recommendation should be rejected.

Commission findings

180. The CCA recommended that the proportion of indirect labour for O&M, for the test period, after adjustments for SCADA related positions, should be consistent with the percentage of indirect labour considered as O&M for the 2012-2014 period, on average.

181. EDTI explained that in periods of high capital activity more costs are transferred to capital, with the result that operating costs are lower than forecast, while in periods of low capital activity, fewer costs are transferred to capital, with the result that operating costs are higher. This may lead to the following. In periods of high capital activity, the forecast costs approved for a period may be recovered in the revenue requirement and again through depreciation on capital assets. In periods of low capital activity, EDTI will not transfer as much cost to capital and is at risk of having operating costs greater than approved in the forecast revenue requirement. This may provide an incentive to over forecast O&M labour in revenue requirement.

182. The Commission considers that in principle, approving a constant ratio of O&M supervision costs to O&M labour costs, similar to the recommendation of the CCA, would incent EDTI to be more cautious in increasing its supervisory staff. The Commission considers that costs associated with FTEs are more likely to increase with an increase in workload than to decrease with a decrease in workload. However, there is insufficient information on the record to support this assumption.

183. The Commission is concerned with the costs included in Account 560 that are unrelated to O&M in other transmission operating accounts. Although the 2014 decision amounts are not provided in Table 4.0-1 of Exhibit 3539-X0126,¹¹² the actual costs increased from \$1.39 million in 2012 to \$1.88 million in 2013 and \$2.05 million in 2014. The forecast costs are \$2.48 million in 2015, \$2.68 million in 2016 and \$2.81 million in 2017.

184. The Commission has reviewed the information provided by the UCA in support of the proposed reduction to Account 560. Based on the Commission's review of the application and evidence on the record regarding forecasting the components of Account 560, the Commission is not persuaded by the UCA evidence to make the proposed reductions based on the trending analysis provided. For this reason, the Commission denies the reductions proposed by the UCA and approves the forecast costs in Account 560.

185. In light of the materiality of Account 560, however, the Commission finds that parties would benefit from additional information on the cost components included in this account. The Commission directs EDTI to provide, as part of future applications, a detailed breakdown of categories and costs included in Account 560, and to separately identify the costs recorded in Account 560 that are not related to O&M in other transmission operating accounts to facilitate consideration of their inclusion and level of cost in this account.

¹¹² Exhibit 3539-X0126, undertaking by Mr. Wiles to Mr. Marriott, Transcript, Volume 1, page 169.

7.4 Employee compensation and benefits

186. EDTI's method for compensating employees is based on the EPCOR Group's (EPCOR) method of compensating employees.

187. The structure for compensating non-union employees has four components:

- base compensation (annual salary)
- employer paid benefits
- short-term incentive (STI)
- mid-term incentive (MTI)

188. EPCOR's structure for compensating union employees has three components:

- base compensation (annual base salary/hourly wages)
- employer paid benefits
- STI

189. EDTI stated in its application that EPCOR seeks to ensure that its total employee compensation is competitive and therefore, under the direction of EPCOR's Human Resources and Compensation Committee, it targets the mid-market or 50th percentile for total employee compensation. EPCOR asserted that this approach ensures that it neither pays its employees too much or too little.¹¹³

190. EDTI submitted that it is also important that each component of its total compensation, which includes a total target direct compensation component and pension/benefits component, is market competitive. To assist with gauging the market competitiveness of its total compensation, EPCOR retained Towers Watson to provide a report of compensation and benefits relative to the market for both non-union and union positions within EDTI, (EPCOR Energy Alberta GP Inc. (EEA) and EPCOR Utilities Inc. (EUI) Corporate Services departments.¹¹⁴ The Towers Watson report entitled 2014 Competitive Compensation and Benefits Analysis was included as Appendix G-2 of the application. In its report, Towers Watson presented two separate analyses for total compensation and pension/benefits.

191. EDTI submitted that, based on Towers Watson's analysis, its total employee compensation is aligned with its philosophy of targeting mid-market or the 50th percentile and:¹¹⁵

- EPCOR's target total direct compensation for non-union executive, director, manager, professional, out of scope and engineer-in-training positions was, on average, market competitive as of mid-2014.
- Target total cash for union positions was market competitive as of mid-2014.
- The value of EPCOR's employer paid benefits is 11.6 per cent above market average for non-union positions and 14.2 per cent below market average for union positions.
- EPCOR's pension and benefits for both non-union and union combined were market competitive.

¹¹³ Exhibit 0003.00.EDTI-3539, EDTI application, paragraphs 324-325.

¹¹⁴ Exhibit 0041.00.EDTI-3539, Appendix G-2, Towers Watson report – 2014 Competitive Compensation and Benefits Analysis.

¹¹⁵ Exhibit 3539-X0193, EDTI argument, paragraph 96.

192. In response to an IR, EDTI submitted that for both the compensation amounts and pension and benefits, EPCOR's overall placement is at or slightly below market when compared to EPCOR's comparator group. EDTI provided details for both union and non-union positions. EDTI proposed that the Commission and interveners can, and should, assess the total compensation package based on these results.¹¹⁶

193. With respect to pension and benefits, EDTI stated that Towers Watson uses a BENVAL analysis or methodology. The purpose of the BENVAL analysis is to capture the value of the pension and benefits program to the employee irrespective of employee utilization or the actual cost to the employer in order for Towers Watson to compare programs on a consistent basis. The BENVAL analysis can be used to show the market competitiveness of EPCOR's pension and benefits plan and whether it is in a good position to compete for talent in the labour pool.¹¹⁷

194. The CCA submitted that there is a fundamental flaw in looking at two different groups, one to assess pension and benefits and the other to assess compensation. In the CCA's view the entire package reflects a balance between pension and benefits and compensation and it is meaningless to evaluate them by reference to separate groups since each group would tend to reflect its own balance. The CCA recommended that EDTI be directed in future proceedings to use the same reference group to assess total compensation, pension and benefits.¹¹⁸

Commission findings

195. The Commission shares the concern of the CCA regarding the use of different comparator groups.

196. To better understand the possible distortion in compensation or benefits caused by using different comparator groups to assess compensation and benefits, the Commission directs EDTI in its next GTA, if it intends to rely on the BENVAL methodology, to file additional information on the BENVAL results for the subset of the comparator group in the benefits study that corresponds to the companies in the main compensation study, i.e., that are common to both the BENVAL study and the main compensation study.

197. As an additional matter, the description and details of the BENVAL methodology was not provided on the record of the proceeding. The Commission directs EDTI in future GTAs if it intends to rely on the BENVAL methodology, to provide the details of the methodology in a format similar to the information provided in EDTI's application in Proceeding 2758, Exhibit 0085.02.EDTI-3758, AUC-EDTI-33(a), Attachment 1 for EDTI's 2013-2014 TFO application.

198. Finally, with respect to EDTI's statement that it is important that each component of its total compensation, which includes a total target direct compensation component and pension/benefits component, is market competitive, the Commission considers that it is not necessary for all components of a compensation plan to be market competitive. Indeed, in some markets, the balance among the components in a compensation plan may vary. However, total compensation should be market competitive, if a company is to remain competitive. The Commission approves a revenue requirement that includes an amount for total compensation, but it is incumbent on the utility to manage the components in its total compensation package.

¹¹⁶ Exhibit 3539-X0012, EDTI-CCA-2015FEB06-007(a).

¹¹⁷ Exhibit 3539-X0193, EDTI argument, paragraph 109.

¹¹⁸ Exhibit 3539-X0198, CCA reply argument, paragraph 69.

7.4.1 Salary escalators

7.4.1.1 Non-union employees

199. EPCOR retained Towers Watson to provide advice with respect to the level of escalation applicable to non-union salaries for 2015, 2016 and 2017. Towers Watson's recommendations are set out in the Memorandum on Non-Union Salary Escalation Factors for 2015 and 2016, dated November 14, 2014 from Towers Watson and attached as Appendix G-1 to the application.¹¹⁹ Included in Towers Watson's memorandum for the consideration of the escalation rates applicable to non-union salaries are the Conference Board of Canada forecasts.¹²⁰

200. EDTI submitted that the evidence of Towers Watson is the best evidence available for salary escalation for non-union employees. As Towers Watson's opinion is the advice that informs EDTI's actual salary escalation for EDTI's board of directors and executive, EDTI proposed it is appropriate that it also be used for purposes of setting rates.¹²¹

201. For 2015 and 2016, Towers Watson recommended a range of escalation for non-union salaries of 3.0 per cent to 4.0 per cent; but did not provide a recommendation for 2017. For 2017, EDTI used the same recommended range of escalation for non-union salaries of 3.0 per cent to 4.0 per cent. In recognition of the fact that compensation for non-union positions is at market levels, EDTI's forecast reflects the escalation of all non-union base salaries at 4.0 per cent for 2015, 2016 and 2017, which is the upper-end of Towers Watson's recommended range for the test periods.¹²²

202. At the time of filing responses to IRs, both Towers Watson and EDTI submitted that EDTI's non-union salary escalation forecast of 4.0 per cent, at the upper end of Towers Watson's recommended range, for 2015-2017 continued to be reasonable.¹²³

203. At the oral hearing, Mr. Resch, witness for Towers Watson, discussed further updates to Towers Watson's work and stated that based on the most recent information, the actual salary escalation for 2015 was tracking closer to the lower end of the recommended range, at three per cent.¹²⁴ Notwithstanding, at the time of the hearing EDTI provided that its actual salary escalation will be at the mid-point of the range, at 3.5 per cent.^{125 126}

204. For its non-union escalators, EDTI submitted that there are compelling reasons why its forecast continues to be reasonable despite the changes in oil prices. EDTI also submitted that the evidence shows there is a strong factual and logical basis, related to EDTI's position as a utility in Edmonton, for concluding that EDTI's wages and salaries are not impacted by the drop in oil prices, including:¹²⁷

- electric transmission utilities constitute a stable industry that is not generally directly impacted by a short-term drop in oil prices

¹¹⁹ Exhibit 0040.00, EDTI-3539.

¹²⁰ Exhibit 3539-X0193, EDTI argument, paragraph 132.

¹²¹ Exhibit 3539-X0193, EDTI argument, paragraph 132.

¹²² Exhibit 3539-X0193, EDTI argument, paragraph 133.

¹²³ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-052 and EDTI-AUC-2015FEB06-003(a).

¹²⁴ Transcript, Volume 7, pages 1281-1282.

¹²⁵ Exhibit 3539-X0193, EDTI argument, paragraph 138.

¹²⁶ Transcript, Volume 7, page 1277.

¹²⁷ Exhibit 3539-X0193, EDTI argument, paragraph 155.

- the impact of the decline in oil prices is offset in part by recent changes to the Canadian dollar exchange rate which has the impact of making imported items more expensive
- the City of Edmonton is experiencing a mini-construction boom in the downtown Edmonton area
- heightened transmission infrastructure activity in Alberta and throughout North America has created a tight electric utilities labour market in Alberta
- the recent fall in the price of oil has not obviated the need for system upgrades to the interconnected Alberta transmission system
- the recent fall in the price of oil does not alter the fact that EDTI has an aging transmission infrastructure which over time must be upgraded¹²⁸

205. EDTI stated that both Dr. Ryan and Mr. Resch confirm these views, with Mr. Resch noting that EDTI is competing for talent primarily with other utility companies that, like EDTI, are less impacted by the price of oil.¹²⁹

206. Finally, EDTI argued that other factors, such as the drop in the Canadian dollar and the rise in minimum wage, will have a countervailing impact. Overall, the evidence shows that there is no direct link between oil prices and EDTI's salary and wages and, as Mr. Resch stated, any impact is likely to be more indirect and long term.¹³⁰

207. For these reasons, EDTI submitted that the evidence in this proceeding demonstrates that EDTI's initial forecast of non-union salary escalation of 4.0 per cent was and continues to be reasonable. While 2015 escalation rates for EDTI were actually 3.5 per cent, Towers Watson's forecast range for 2016 and 2017 continues to be in the 3.0 to 4.0 per cent range. Overall this demonstrates that despite the change in economic circumstances, EDTI's original forecast was reasonable at the time it was made, and continues to be a reasonable forecast, and should be approved as filed.¹³¹

208. The UCA noted that the most recent data available from the Conference Board of Canada escalation rates for salaries and wages forecasts 1.2 per cent in 2015, 2.2 per cent in 2016 and 2.9 per cent in 2017.¹³² Having regard to the best information available with respect to labour escalation rates, the UCA submitted that EDTI has not established that its forecast escalation rates for both non-union and union labour are reasonable. The UCA recommended that the forecast non-union labour escalation rate should be reduced to the low end of the range recommended by Towers Watson, which is 3.0 per cent, "based on the best available information regarding the overall softening labour market."¹³³

209. The CCA submitted that the multitude of structural changes impacting the price of oil, the actions of the Bank of Canada in relation to interest rates, the value of the Canadian dollar relative to the U.S. dollar (at a time when the U.S. economy is performing strongly with consequent upward pressure on U.S. interest rates) as well as the adjustments, including cost cutting and other efficiency measures undertaken by the oil industry to cope with low oil prices, would all have an impact on the Alberta real gross domestic product growth, unemployment rate,

¹²⁸ Exhibit 3539-X0193, EDTI argument, paragraph 145.

¹²⁹ Transcript, Volume 7, pages 1282-1285.

¹³⁰ Transcript, Volume 7, page 1284.

¹³¹ Exhibit 3539-X0193, EDTI argument, paragraph 157.

¹³² Transcript, Volume 7, page 1397.

¹³³ Exhibit 3539-X0192, UCA argument, paragraph 18.

and the Alberta consumer price index, as well as the Alberta average salaries and wages per employee in the days and months to come.¹³⁴

210. The CCA recommended that the escalation rates for all categories of salaries and wages, as well as contractor cost escalation factors, should reflect the Alberta average wages and salary escalation rates forecast by the Conference Board of Canada as of May 7, 2015, at the time of the hearing.¹³⁵ However, any escalation rates that have already been contractually determined should not be subject to this recommendation.¹³⁶

211. EDTI replied that the CCA's position appears to be that Towers Watson's evidence should be ignored in favour of the use of the Conference Board of Canada figures. EDTI explained that the evidence of Towers Watson is the best evidence on which to base EDTI's non-union employee salary escalation rates for the test period.

212. EDTI submitted that:

TW's [Towers Watson's] analysis is also a superior tool than the general Conference Board of Canada estimate of increases in Alberta average wages and salaries. TW's analysis includes consideration of Conference Board of Canada figures related to Utilities, Oil and Gas, Public Sector, General Industry (Alberta) and General Industry (National). TW's analysis also considers data from its own survey reports specific to energy services and utilities and Mercer's 2014/2015 Canada compensation planning survey specific to the energy industry. Using these sources, TW is able to isolate salary and wage increases for the energy services and utility sectors in particular, and is not confined to a general average of wages and salaries for all of Alberta. The TW report also takes into account economic forecasts for Canadian industry in general and the Alberta energy sector. Taken together, TW's analysis is a more refined approach that is based on a more complete set of data that is specific to EDTI. As such it is clearly preferable to the average of wages and salaries for all of Alberta as forecast by the Conference Board of Canada.¹³⁷

213. Further, EDTI argued that the evidence provided by Mr. Resch supports that the actual salary escalation for 2015 was tracking closer to the lower end of the range, at 3.0 per cent. Therefore, for 2016 and 2017, the 3.0 to 4.0 per cent range continues to be reasonable.¹³⁸

214. EDTI also noted that its 2015 non-union wages have already been established for 2015 at 3.5 per cent. It would be unfair to base EDTI's 2015 non-union escalators on Conference Board of Canada estimates as at mid-2015, as that information only became available after EDTI had already determined its wages for the year. If the most up-to-date information is to be used, the 2015 actual increase is the best information available.¹³⁹

¹³⁴ Exhibit 3535-X045, CCA evidence, paragraph 21.

¹³⁵ Transcript, Volume 7, page 1399, line 14.

¹³⁶ Exhibit 3539-X0194, CCA argument, paragraph 17.

¹³⁷ Exhibit 3539-X0197, EDTI reply argument, paragraph 32.

¹³⁸ Exhibit 3539-X0197, EDTI reply argument, paragraph 33.

¹³⁹ Exhibit 3539-X0197, EDTI reply argument, paragraph 34.

215. The UCA replied that the Commission should use the best information available respecting escalation rates for non-union salaries and that it supports a 3.0 escalation rate rather than the forecast rates provided in EDTI's application. The best available information includes:¹⁴⁰

- Messrs. Resch and Baraniecki's evidence respecting 2015 actual salary escalation, namely that the actual rate is lower than EDTI's forecast
- Mr. Retnanandan's evidence that the negative impact of the slow recovery of natural resource prices on the Alberta economy is likely to negatively affect salary escalation in 2016 and 2017¹⁴¹

Commission findings

216. In keeping with the Commission's finding above in Section 5 with respect to the best available information and given the timing of the application, the Commission accepts EDTI's 2015 actual escalation for non-union salaries of 3.5 per cent. The Commission notes this escalation factor most closely matches expectations at the close of record. At the hearing, Mr. Baraniecki on behalf of EDTI confirmed that the actuals for 2015 would be "closer to the middle range"¹⁴² and a 3.5 per cent escalation rate for non-union labour is supported by the evidence of EDTI and Towers Watson.

217. For 2016 and 2017, EDTI submitted in argument that its original forecast of 4.0 per cent is still reasonable and should be approved. The Commission finds that, at the time EDTI filed its application, the Alberta average wages and salary escalation rates as forecast by the Conference Board of Canada were 3.1 per cent for 2016 and 3.2 per cent for 2017.¹⁴³ Near the end of the hearing, the revised forecast by the Conference Board of Canada as of May 7, 2015 was 2.2 per cent for 2016 and 2.9 per cent for 2017.

218. Towers Watson recommended a range of three to four per cent for 2016 and 2017 non-union salary escalators. However, the Commission does not accept that the upper range of four per cent is warranted. The experts providing evidence in the proceeding indicated that salary escalators are on a downward trend.¹⁴⁴ The evidence before the Commission at the close of record suggests that salary escalation rates are on a downward trend, which could be partially affected by changes in the Alberta economy.

219. There is a downward trend in the Conference Board of Canada forecasts of Alberta salaries and wages for 2015, 2016 and 2017, since EDTI filed its application. The Commission agrees with the UCA that three per cent is more reflective of the current market, based on the best available information on the record. Three per cent is within Towers Watson's recommended range and is more consistent with May 7, 2015 Conference Board of Canada forecasts of 2.2 per cent for 2016 and 2.9 per cent for 2017. Accordingly, the Commission approves a 2016 and 2017 non-union salary escalation rate of three per cent.

220. The record of the proceeding is unclear as to whether the 3.5 per cent escalation rate proposed for 2015 was inclusive of all labour, merit and step increases. In the compliance filing to this decision, the Commission directs EDTI to confirm whether its proposed escalation rate for

¹⁴⁰ Exhibit 3539-X0196, UCA reply argument, paragraphs 14-16.

¹⁴¹ Exhibit 3539-X0045, CCA evidence, paragraphs 10-23.

¹⁴² Transcript, Volume 7, page 1277.

¹⁴³ Exhibit 0043.00.EDTI-3539, Appendix G-4, Table 1, forecast as of June 25, 2014.

¹⁴⁴ Transcript, Volume 7, pages 1281-1282.

non-union employees included all labour, merit and step increases. EDTI is also directed to indicate in its compliance filing, whether its application of the approved escalation rates for non-union employees includes all labour, merit and step increases.

7.4.1.2 Civic Service Union 52

221. At the time of filing the application, EDTI's collective agreement with the Civic Service Union 52 (CSU) had expired and EDTI was in the process of negotiating a new collective agreement with the CSU. EDTI applied for a placeholder escalation factor of 3.0 per cent for 2015, 3.1 per cent for 2016, and 3.2 per cent for 2017 based on the Conference Board of Canada forecast of growth in wages and salaries per employee in Alberta.¹⁴⁵

222. During the course of this proceeding, a new collective agreement with the CSU was ratified, and the agreement covered the period 2014-2017. Under the new collective agreement, the salary escalation for CSU employees was 3.86 per cent in 2014, 3.16 per cent in 2015, 2.33 per cent in 2016 and 2.23 per cent in 2017.¹⁴⁶ EDTI proposed to update its CSU employee escalation rates in its refiling application to reflect the new collective agreement.¹⁴⁷

223. The UCA did not support the use of placeholders with respect to union escalation rates. The UCA stated that such placeholders operate to shift the risk to customers, and reduce incentives for the utility to negotiate the best possible collective agreement. The UCA noted that, in Decision 2014-269, the Commission held that, having found EDTI's forecast CSU escalation rate to be reasonable, a placeholder was not necessary.¹⁴⁸

224. The CCA stated that since the Conference Board of Canada forecasts constitute the best available information on escalation rates for salaries and wages, the escalation rates for all categories of salaries and wages, as well as contractor cost escalation factors, should reflect the Alberta average wages and salary escalation rates forecast by the Conference Board of Canada as of May 7, 2015.¹⁴⁹ However, any escalation rates that have already been contractually determined should not be subject to this recommendation.¹⁵⁰

225. For CSU escalation rates, EDTI replied that the CCA's position is consistent with EDTI's proposal to use the escalation rates in its new ratified collective agreement with the CSU.¹⁵¹

226. In argument, EDTI noted that, because the 2014 escalation rate is greater than the 2014 approved amount, following ratification of the collective agreement, the difference between the decision amount and the actual amount will have a compounding effect on subsequent years, and should be accounted for on a going forward basis.¹⁵²

Commission findings

227. During the course of the proceeding, the collective agreement with the CSU was ratified for the period 2014-2017. For 2015-2017, the Commission finds EDTI's salary escalation rates

¹⁴⁵ Exhibit 0003.00.EDTI-3539, EDTI application, paragraphs 356-358.

¹⁴⁶ Transcript, Volume 6, page 1239 and pages 1246-1247.

¹⁴⁷ Exhibit 3539-X0193, EDTI argument, paragraph 127.

¹⁴⁸ Decision 2014-269, paragraph 160.

¹⁴⁹ Transcript, Volume 7, page 1399, line 14.

¹⁵⁰ Exhibit 3539-X0194, CCA argument, paragraph 17.

¹⁵¹ Exhibit 3539-X0197, EDTI reply argument, paragraph 27.

¹⁵² Exhibit 3539-X0193, EDTI argument, paragraph 127.

agreed to in the new collective agreement for the CSU to be reasonable on a final basis. No placeholder during the forecast period is required, given that the agreement with the CSU was ratified during the course of the proceeding and the actual escalation rates are known. In arriving at this finding, the Commission has also considered that the CSU escalation rates for the four years negotiated in the agreement are, on the whole, comparable to the approved escalation rates for non-union employees. Therefore, the Commission approves salary escalation rates for the CSU of 3.16 per cent in 2015, 2.33 per cent in 2016 and 2.23 per cent in 2017. The Commission directs EDTI to reflect the ratified collective agreement CSU employee escalation rates in its compliance filing application to this decision.

228. With respect to EDTI's assertion that the actual 2014 escalation rate following ratification of the collective agreement should be accounted for on a go-forward basis, the Commission finds that EDTI should account for the actual 2014 escalation rate in calculating its revenue requirement for the test period, in its compliance filing to this decision. In the compliance filing to this decision, EDTI is also directed to explain all of the adjustments to revenue requirement it has included to account for the actual 2014 escalation rate for the CSU agreement.

7.4.1.3 International Brotherhood of Electrical Workers 1007

229. When EDTI filed its 2013-2014 application, the collective agreement with the International Brotherhood of Electrical Workers 1007 (IBEW) was to expire at the end of 2015. Based on the 2013-2015 collective agreement with the IBEW, EDTI applied a salary escalation rate of 3.50 per cent for 2015 for IBEW employees in its 2015 revenue requirement forecast.¹⁵³

230. EDTI submitted that, rather than attempt to forecast the outcome of the upcoming collective bargaining process or potentially influence the outcome by publishing a forecast, it prepared the application using a placeholder escalation of 3.1 per cent for 2016 and 3.2 per cent for 2017, based on the Conference Board of Canada forecast of growth in wages and salaries per employee in Alberta.¹⁵⁴

231. By the conclusion of the oral hearing, EDTI had not reached an agreement with the IBEW. EDTI proposed to update the IBEW salary escalators once a memorandum of understanding had been reached and to reflect any associated escalation rate change for the IBEW agreement into the calculation of EDTI's 2016 and 2017 revenue requirements in its refiling application.¹⁵⁵

232. The CCA's position with respect to salary escalation rates for the IBEW was the same as for the CSU salary escalation rates. The CCA stated that since the Conference Board of Canada forecasts constitute the best available information on escalation rates for salaries and wages, the escalation rates for all categories of salaries and wages, as well as contractor cost escalation factors, should reflect the Alberta average wages and salary escalation rates forecast by the Conference Board of Canada as of May 7, 2015.

233. The UCA submitted that it did not support the use of placeholders with respect to union escalation rates. The UCA stated that such placeholders operate to shift the risk to customers,

¹⁵³ Exhibit 0003.00.EDTI-3539, EDTI application, paragraphs 360-361.

¹⁵⁴ Exhibit 0003.00.EDTI-3539, EDTI application, paragraph 363.

¹⁵⁵ Exhibit 3539-X0193, EDTI argument, paragraph 130.

and reduce incentives for the utility to negotiate the best possible collective agreement. The UCA recommended that, should the forecast IBEW escalation rates be found to be reasonable by the Commission, they should be used as a final rate, rather than as a placeholder.¹⁵⁶

234. EDTI disagreed with the UCA's position and stated that the use of placeholders for its union escalation rates is the most reasonable approach because it will not compromise EDTI's negotiating position with its unions by effectively pre-determining the outcome of the collective bargaining process. EDTI submitted that its proposal to update its placeholder 2016 and 2017 escalation rates for IBEW union employees in its refiling application, if a memorandum of understanding is reached, is an appropriate approach that does not interfere with the collective bargaining process. It will also ensure that EDTI's approved tariffs will reflect actual, arm's length negotiated union escalation rates for 2016 and 2017.¹⁵⁷

Commission findings

235. EDTI requested placeholders of 3.1 per cent for 2016 and 3.2 per cent for 2017 for IBEW salary escalators.

236. The Commission does not accept EDTI's position that a placeholder is required for the non-union escalators and acknowledges that the salary escalators negotiated between EDTI and IBEW may be higher or lower than the forecasts approved in this decision.

237. Given that the Commission has approved salary escalation rate of 3.0 per cent for non-union employees for 2016 and 2017, the Commission similarly approves 3.0 per cent for IBEW salary escalators for the years 2016 and 2017 on a final basis. The 3.0 per cent approved is consistent with other salary escalators approved for non-union employees and more closely aligns to the May 7, 2015 Conference Board of Canada forecasts on the record of this proceeding.

7.4.2 Short-term incentive program

238. EDTI submitted that its STI program is designed to provide employees with a competitive incentive plan that reflects EUI's corporate and business unit performance, and individual performance. Table 14 shows EDTI's 2014 actual STI amounts paid to employees:

¹⁵⁶ Exhibit 3539-X0192, UCA argument, paragraph 19.

¹⁵⁷ Exhibit 3539-X0197, EDTI reply argument, paragraph 28.

Table 14. EDTI 2014 STI performance for amounts paid out in 2015 for 2014

	A	B	C	D	E	F	G
	% weight	Threshold points (50% of target)	Target points (100% of target)	Maximum points (150% of target)	Actual performance rating	Actual points (% points)	Awarded points (% points)
1 EDTI financial performance	10	5	10	15	Above target	14.73	
2 Operational efficiency	30	15	30	45	Above target	36.67	
3 Customer service	30	15	30	45	Above threshold	22.50	
4 Subtotal	70	35	70	105		73.90	70.00
5 Safety	30	15	30	45	Above target	39.40	30.00
6 Total Pool A: managing the business (maximum 100 points awarded)	100	50	100	150		113.30	100.00

Source: Exhibit 3539-X0089, EDTI Additional Information – 2014 Actuals, Table 1.6.3.1-1.

239. EDTI submitted that its incentive compensation structure is designed to attract and retain qualified employees and incent them to provide excellent service, which benefits both customers and the utility shareholder. EDTI’s senior management develops specific activity measures for the STI program that will engage and focus all employees on improving EDTI’s overall performance as a utility service provider.¹⁵⁸

240. EDTI noted the selection of STI program metrics in the areas of safety, operational efficiency, and customer service (the business unit activity measure component of the STI program) is done each year, based on key focus areas and operational priorities identified by EDTI management.¹⁵⁹

241. In its update for 2014 actuals, EDTI provided its 2014 STI program individual metrics, which include the following:¹⁶⁰

- total recordable injury/illness frequency rate
- workplace observations completed
- variance of actual to base approved capital
- controllable operating cost per customer
- SAIDI
- customer service index

242. For the business unit activity measures in 2015, in addition to the safety metrics and customer service metrics, EDTI adopted two operational efficiency metrics: “Actual vs. Base Capital” and “Controllable Operating Cost per Customer.” These are related to controllable operations and maintenance and controllable capital.¹⁶¹ EDTI explained that the controllable operating and capital costs are derived from EDTI’s budget so that managers and employees have good visibility into actual performance relative to the targets. EDTI argued that from a productivity perspective, employees can look at the measure and actually make adjustments

¹⁵⁸ Exhibit 3539-X0193, EDTI argument, paragraph 159.

¹⁵⁹ Exhibit 3539-X0193, EDTI argument, paragraph 160.

¹⁶⁰ Exhibit 3539-X0089, EDTI additional information – 2014 actuals, page 6-7.

¹⁶¹ Exhibit 3539-X0193, EDTI argument, paragraph 161.

throughout the year, as required, which incents productivity.¹⁶² EDTI's 2015 STI program individual metrics include the following:¹⁶³

- all injury frequency rate
- near miss reporting
- variance of actual to base approved capital
- controllable operating cost per customer
- SAIDI
- customer service index

243. The CCA expressed concern that the "Variance Actual to Base Approved Capital" metric was not designed to incent behaviour to encourage completion of projects because it ignores desirable outcomes, such as achieving economic efficiency in design, planning, capital budgeting and project execution.¹⁶⁴ The CCA recommended that EDTI consider metrics that would facilitate prudent and efficient construction practices, such as:¹⁶⁵

- the lowest cost engineering design and capital budgets reflecting economic efficiency considerations
- cost effective procurement, project management and project execution
- proactive risk management practices and coordination systems to ensure negative cost variances are anticipated and minimized
- completion of projects on schedule in accordance with quality, scope and functionality requirements

244. EDTI replied that if all factors identified by the CCA were included in the STI program, the number and complexity of the metrics would be neither feasible to administer nor effective at engaging and focusing employees on improving EDTI's overall performance. In addition, EDTI submitted that it ensures that economic efficiency in the design, planning, capital budgeting, risk management and project execution aspects of all capital projects is reflected in employee performance evaluations of individual employees involved in capital projects. EDTI stated its existing incentive program combined with its budgeting approach, management process and project variance management processes already address the STI program metrics that the CCA suggested EDTI consider.¹⁶⁶

245. EDTI forecast total STI amounts for 2015, 2016 and 2017 of \$0.96 million, \$1.00 million and \$1.03 million, respectively.¹⁶⁷ Only the "Pool A" portion of the forecast STI amounts is included in revenue requirement. The Pool B costs represent STI components that exceed a weighting of 10 per cent related to income measures and EDTI stated that Pool B costs were not included in the revenue requirement on a forecast basis, as was approved in Decision 2012-272 and Decision 2014-269.¹⁶⁸

¹⁶² Transcript, Volume 4, pages 753-756 and Transcript, Volume 5, pages 945-948.

¹⁶³ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-048.

¹⁶⁴ Exhibit 3539-X0194, CCA argument, paragraphs 54-56.

¹⁶⁵ Exhibit 3539-X0194, CCA argument, paragraph 57.

¹⁶⁶ Exhibit 3539-X0197, EDTI reply argument, paragraphs 36-37.

¹⁶⁷ Exhibit 0003.00.EDTI.3539, Table 1.6.3.3-2, line 8, Table 1.6.3.4-2, line 8 and Table 1.6.3.5-2, line 8.

¹⁶⁸ Exhibit 0003.00.EDTI.3539, application, paragraph 615, PDF pages 224 and 225 of 900.

Commission findings

246. The Commission accepts EDTI's explanation that its STI program in combination with other management processes addresses certain outcomes with respect to capital budgeting and project execution, which may incent employees to provide excellent service and reduce costs. The Commission approves EDTI's forecast STI program and the forecast STI amounts to be included in revenue requirement for 2015, 2016 and 2017.

247. The Commission, however, is concerned that STI metrics are set yearly and the application before the Commission is for a three-year test period, and the 2016 and 2017 metrics have not yet been established.

248. With respect to the 2016 and 2017 STI metrics, the Commission reminds EDTI of the general principle that incentive programs, that are included for recovery in revenue requirement, should be designed so that any resulting benefits will accrue to customers. In Decision 2012-343,¹⁶⁹ the Commission stated:

The Commission views that the parameters of approval for DERS' LTIS incentive programs set out in Decision 2009-238 are still applicable for the test years 2012 to 2014. The Commission agrees with the CCA that there must be a net benefit to DERS' regulated customers in Alberta for expense recovery and finds that the LTIS costs included in DERS' revenue requirement, which are related to the financial performance of Centrica plc, an entity outside the regulated business in Alberta, does not benefit DERS' customers.¹⁷⁰

249. The Commission's findings with respect to the capitalization of STI costs is found in Section 10.1 of this decision. In reviewing opening rate base the Commission will assess the prudence of the STI costs included in the cost of assets.

7.4.3 Mid-term incentive program

250. Historically the Commission has not approved the inclusion of MTI program costs in EDTI's revenue requirement. The CCA raised the issue of MTI in its reply argument, and submitted that if designed properly with clear objectives for efficiency in capital project planning, budgeting and execution, MTI could serve as an effective tool for incenting better performance by employees.¹⁷¹

251. The CCA submitted that EDTI noted that the TTDC (target total direct compensation: TTC plus MTI) of EUI's "stratum 4" non-union incumbents was 18 per cent above market, whereas the TTC (target total cash: Salaries and STI) result was 10 per cent above market. EDTI also noted that the difference between the two measures (TTDC and TTC) is eight per cent above market and this difference is due to MTI, for which EDTI is not asking for recovery as part of the revenue requirement.¹⁷²

252. The CCA is of the view that as an alternative to excluding 100 per cent of MTI payments from revenue requirement, EDTI could have designed the MTI with a structure that would incent

¹⁶⁹ Decision 2012-343: Direct Energy Regulated Services, 2012-2014 Default Rate Tariff and Regulated Rate Tariff, Proceeding 1454, Application 1607696-1, December 21, 2012.

¹⁷⁰ Decision 2012-343, paragraph 83.

¹⁷¹ Exhibit 3539-X0198, CCA reply argument, paragraph 66.

¹⁷² Exhibit 3539-X0198, CCA reply argument, paragraph 64.

better employee performance on EDTI's capital projects while conforming to the plus or minus 10 per cent of the 50th percentile for TTDC. The CCA argued that this alternative could become an effective tool for facilitating better performance on capital projects for the benefit of EDTI's customers.¹⁷³

253. Rather than losing the potential benefits of MTI, the CCA recommended that EDTI be instructed to design a suitable MTI structure that can incent better performance on longer term capital projects, while ensuring TTDC stays within plus or minus 10 per cent of the 50th percentile in future proceedings.¹⁷⁴

Commission findings

254. In Decision 2012-272, the Commission denied recovery of EDTI's MTI program costs.¹⁷⁵ Additionally, the first time that MTI program costs have been raised in this proceeding was in the CCA's reply argument. The Commission finds that, because the issue of MTI structure was only raised in argument, parties have not had the opportunity to fully address the merits of the CCA's proposal. Accordingly, the CCA's request for a direction with respect to MTI is denied.

7.4.4 Cost escalators – contractors, materials and other

255. EDTI retained Dr. David Ryan to recommend appropriate escalation factors to be applied to contractors, materials, and other costs for the 2015 to 2017 test years. Dr. Ryan's report, dated July 28, 2014, was entitled Forecast Values of Escalators and was included as Appendix G-4 to the application.¹⁷⁶ Over the course of the proceeding, Dr. Ryan provided two updates to his report. The first update was provided in response to an IR from the Commission and was a revision of Dr. Ryan's July 28, 2014 report, and dated January 26, 2015.¹⁷⁷ The second update to Dr. Ryan's reports, dated June 17, 2015, was provided in response to an undertaking at the oral hearing.¹⁷⁸

256. The only issue explored by parties was whether Dr. Ryan's updated analysis should be used to determine EDTI's escalation factors. EDTI submitted that based on regulatory principles, fairness to the utility and the evidence overall, the Commission should not do so.¹⁷⁹

257. EDTI submitted that the escalation rates have not substantially changed from the forecast included in its original application. A comparison of the escalation rates in Dr. Ryan's reports shows that the only material changes are in the contractor category for 2015 and 2016 and the other category in 2015.

258. EDTI also stated that the escalation rates provided in Dr. Ryan's updated report dated June 17, 2015 are the most recent, but are not definitive and could change as the underlying data is updated. The most recent forecasts are not necessarily more accurate and EDTI submitted that

¹⁷³ Exhibit 3539-X0198, CCA reply argument, paragraph 66.

¹⁷⁴ Exhibit 3539-X0198, CCA reply argument, paragraph 67.

¹⁷⁵ Decision 2012-272, paragraphs 128-129 and paragraph 404.

¹⁷⁶ Exhibit 0043.00.EDTI-3539.

¹⁷⁷ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-053.

¹⁷⁸ Exhibit 3539-X0185.01, undertaking from Dr. Ryan to Mr. Marriott.

¹⁷⁹ Exhibit 3539-X0193, EDTI argument, paragraph 117.

accepting the updated forecast would be inconsistent with the regulatory principles of prospective rate-making and would introduce the potential for unfairness to the utility.¹⁸⁰

259. EDTI claimed that it prepared its application based on the best information available at the time. EDTI argued that using data from midway through 2015, well into the test period, violates the regulatory principles of prospective ratemaking. As there will inevitably be both ups and downs in terms of the accuracy of a forecast, the forecast should not be updated for only those items that may happen to have decreased with the passage of time.¹⁸¹

260. The UCA argued that none of the submissions put forward by EDTI justify not using the available updated escalation rates. The Commission has repeatedly confirmed that the best information, available at the time that it makes its decision, should be used to assess the reasonableness and accuracy of the forecasts and the methodology used in preparing the forecasts.¹⁸²

261. Both the UCA and the CCA submitted that forecasts are not definitive by nature. However, the relevant point in time for consideration is the time when the Commission makes its decision, and the Commission should have the best information available at that time to establish rates.¹⁸³

262. The UCA and the CCA noted that EDTI is in the best position to determine what portions of its forecast require updating to reflect changes in assumptions or current expectations and conditions. The escalation rates used in the application are major assumptions given EDTI's size, and they could have been updated at any point during the proceeding.

263. The CCA stated that as long as there is no evidence of forecast bias, the best available forecast should be used.¹⁸⁴ Further, the CCA stated that the change in escalation assumptions did not happen simply due to the passage of time, but due to a fundamental change in Alberta's economic outlook.¹⁸⁵

264. Both the UCA and CCA recommended that the updated escalation rates for contractors, materials and other provided by Dr. Ryan be used for purposes of the 2015-2017 forecast.¹⁸⁶

Commission findings

265. Dr. Ryan, on behalf of EDTI, provided the following updated forecast values of escalators at June 17, 2015, in response to an undertaking in the hearing:

¹⁸⁰ Exhibit 3539-X0193, EDTI argument, paragraphs 120-124.

¹⁸¹ Exhibit 3539-X0193, EDTI argument, paragraphs 123-124.

¹⁸² Exhibit 3539-X0196, UCA reply argument, paragraphs 7-10.

¹⁸³ Exhibit 3539-X0196, UCA reply argument, paragraph 12 and Exhibit 3539-X0198, CCA reply argument, paragraphs 14-15.

¹⁸⁴ Exhibit 3539-X0196, UCA reply argument, paragraph 11 and Exhibit 3539-X0198, CCA reply argument, paragraph 10.

¹⁸⁵ Exhibit 3539-X0198, CCA reply argument, paragraph 15.

¹⁸⁶ Exhibit 3539-X0196, UCA reply argument, paragraph 13 and Exhibit 3539-X0198, CCA reply argument, paragraph 19.

Table 15. Forecast values of escalators as at June 17, 2015

Category	2013	2014	2015F	2016F	2017F
Contractor costs	4.7	4.5	1.2	2.2	2.9
Other costs	1.4	2.6	0.8	2.2	2.2
Materials costs	0.1	2.7	1.8	2.2	1.7

Source: Exhibit 3539-X0185.01.

266. In Section 5 of this decision, the Commission stated that it will consider the forecasts submitted in the application given the best available information on the record of the proceeding. This approach is consistent with prospective rate making and fairness principle. The Commission finds that the forecasts in Dr. Ryan's June 17, 2015 update reflect more recent current conditions in the Alberta economic environment.

267. Accordingly, the Commission accepts that the most recent update of Dr. Ryan provides the best available information and the Commission approves the forecast escalators set out in Table 15 for contractor costs, other costs and materials costs for 2015-2017.

7.5 Administrative and general expenses

268. EDTI classifies its administrative and general costs in nine categories, consistent with the USA accounts 920 to 924, 930.2, 934, 935 and 941.

269. EDTI stated that administrative and general costs are directly assigned to EDTI transmission where possible. Costs not directly assigned to transmission administrative and general expenses are allocated based on MOP allocations discussed in the shared services section of this decision.¹⁸⁷ EDTI provided an analysis of the various components comprising each of the cost categories and reasons for the variances between decision and actual amounts for the years 2013 and 2014. EDTI also provided reasons for any forecast increases or decreases in the 2015-2017 test period from the 2014 updated forecast amounts.¹⁸⁸

270. In order to allow for a comparison of year-over-year costs, the Commission has prepared the following table, which summarizes historical and forecast administrative and general costs:

¹⁸⁷ Exhibit 0003.00.EDTI-3539, application, paragraphs 1026-1027, PDF page 372 of 900.

¹⁸⁸ Exhibit 0003.00.EDTI-3539, application, Section 6.0, starting at PDF page 371 of 900.

Table 16. Transmission administrative expenses by USA operating account 2013-2017

USA	Description of USA	2013 Decision 2014-269	2013 actual	2014 Decision 2014-269	2014 actual	2015 forecast	2016 forecast	2017 forecast
		(\$ million)						
920	Administrative and general salaries	2.20	2.59	2.43	2.81	2.35	2.44	2.53
921	Office supplies and expenses	0.41	0.34	0.47	0.33	0.40	0.34	0.27
922	Administrative expenses transferred	(3.20)	(2.96)	(2.35)	(2.71)	(3.78)	(3.91)	(4.04)
923	Outside services employed	0.52	0.27	0.33	0.31	0.34	0.29	0.29
924	Insurance premiums	0.37	0.37	0.38	0.41	0.43	0.46	0.50
930.2	Asset usage fee (EDTI functions)	1.31	1.31	1.29	1.30	1.30	1.91	2.51
934	IT general and administration (G&A) expenses	0.29	0.30	0.37	0.33	0.39	0.39	0.41
	Subtotal G&A and common operations	1.90	2.22	2.94	2.78	1.43	1.92	2.47
941	Disallowed/non-utility costs	(0.46)	(0.66)	(0.30)	(0.96)	(0.29)	(0.26)	(0.24)
	G&A and common operations net of disallowed	1.44	1.56	2.64	1.81	1.14	1.66	2.22
935	General O&M - building facility operations	1.13	1.14	1.14	1.11	1.26	1.33	1.37
	Total administrative costs	2.57	2.70	3.78	2.93	2.40	3.00	3.60
Over (under) 2013 and 2014 decision to actuals or forecast \$			0.13		(0.85)	(1.38)		
Over (under) 2013 and 2014 decision to actuals or forecast %			5.06%		(22.49%)	(36.51%)		

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, schedules 23-1 and 24-1.

271. Table 16 above shows that administrative and general expenses decreased from 2014 decision and actual amounts to 2015 forecast amounts. EDTI indicated that the increases in its 2016 and 2017 forecast costs are primarily due to asset usage fees to be paid by transmission to distribution reflecting the completion of work related to the work centre redevelopment project.¹⁸⁹

272. No party submitted argument or reply argument on EDTI's administrative and general expenses.

Commission findings

273. The Commission has reviewed the information provided by EDTI respecting the administrative expenses identified in Table 16 above and the corresponding variance explanations provided by EDTI.

274. The following accounts have changed by significant amounts as presented in the preceding table. The administrative expenses transferred (Account 922) increased from \$2.35 million as approved in Decision 2014-269 to \$2.71 million actuals. As discussed in Section 7.4.2, this change is due to the capitalization of STI costs in 2014 actuals. The 2015

¹⁸⁹ Exhibit 0003.00.EDTI-3539, application, paragraphs 1129 and 1132, PDF pages 396 and 397 of 900. Information regarding the work center redevelopment project is found in T-CBC-22 of EDTI's application.

forecast amount of \$3.78 million has increased by \$1.07 from the 2014 actuals. This increase is also primarily due to the capitalization of STI costs commencing in 2015 and the use of distribution resources to complete transmission capital projects.

275. Asset usage fees (Account 930.2) approved in Decision 2014-269 were \$1.29 million, actuals were \$1.30 million and forecast costs for 2015 were \$1.30 million. The fees increased to \$1.91 million in the 2016 forecast and \$2.51 million in the 2017 forecast.

276. Disallowed utility costs (Account 941) were more than forecast in 2013 (\$0.66 million in 2013 actuals compared to \$0.46 million approved in Decision 2014-269) and 2014 (\$0.96 million actuals compared to \$0.30 million approved in Decision 2014-269). This increase in disallowed costs in 2014 was the result of an increase in non-recoverable at risk compensation related to STI Program Pool B and MTI Program incentive payments. These payments were not included in the 2014 decision revenue requirement and will not be included in the 2015-2017 revenue requirement.

277. Based on its review of the forecast costs, and the evidence and explanations provided by EDTI, the Commission accepts EDTI's forecast general and administrative expenses. Subject to any findings respecting EDTI's MOP allocations set out in the shared services section of this decision (Section 7.5.1), the Commission approves EDTI's administrative and general expenses, as filed.

7.5.1 EDTI shared services costs

278. EDTI operates distribution and transmission on an integrated basis. Common costs, primarily in the nature of general and administrative costs, are allocated between distribution and transmission through the MOP.¹⁹⁰ Also, common field operating costs and distribution & transmission (D&T) asset usage fees are allocated between distribution and transmission using a cost allocation model. Where the cost of carrying out a common field operating activity or affiliate service can be reasonably tracked on a transaction by transaction basis, the costs are directly assigned on an actual time-spent-per-activity basis.¹⁹¹ Asset usage fees are referred to as "D&T asset usage fees" and "affiliate asset usage fees," respectively. The costs associated with providing common field operating activities and affiliate services, as well as D&T and affiliate asset usage fees, are determined on a cost recovery basis (including depreciation and return) plus a cost recovery surcharge of 20 per cent. All asset usage fees are allocated rather than directly assigned.

EDTI shared services – MOP

279. EDTI uses an overhead percentage to allocate indirect support costs associated with ongoing administrative functions that are necessary to enable EDTI to carry out its operating activities and capital projects, but cannot be directly assigned to capital or O&M, to MOP costs. EDTI states that the 2015-2017 MOP forecasts are consistent with the 2013-2014 MOP costs. The historical and forecast expense items included in MOP are provided below:

¹⁹⁰ Exhibit 0003.00.EDTI-3539, application, PDF pages 123-124 of 900.

¹⁹¹ Exhibit 3539-X0021, Appendix D-1-1, PDF pages 2-3.

Table 17. Costs included in master overhead pool 2011-2017

Master overhead categories		A Primary Section Ref	B USA Section Ref	C MFR Ref	D USA	E 2012 A	F 2013 D	G 2013 A	H 2014 D	I 2014 F	J 2015 F	K 2016 F	L 2017 F
(\$ million)													
1	O&M supervision and engineering	3.1.1	4.1.4	S5-1	560	3.41	3.88	3.64	4.16	3.90	3.04	3.18	3.33
2	IT support of field applications	3.1.2	4.7	S5-1	575	1.80	1.92	1.80	2.04	1.91	2.05	2.34	2.40
3	Admin and general salaries (including EDTI incentive comp)	3.1.3, 3.1.3.1	6.1.1, 6.1.3	S 24-1	920	7.34	7.10	8.24	7.61	6.39	6.58	6.65	6.96
4	Office supplies and expenses	3.1.4	6.2.2	S 24-1	921	0.92	1.84	1.44	2.04	1.66	1.64	1.37	1.10
5	Administrative expenses transferred – credit	3.1.5	6.3	S 24-1	922	(0.66)	(0.97)	(0.88)	(0.84)	(0.53)	(0.54)	(0.56)	(0.59)
6	Outside services employed	3.1.6	6.4.2	S 24-1	923	0.45	0.79	0.37	0.82	0.80	0.73	0.62	0.65
7	Supply chain management	3.1.7	4.6.6		566	-	0.79	0.57	0.97	0.91	0.77	0.80	0.83
8	Insurance premiums	3.1.8	6.5.3	S 24-1	924	0.06	0.07	0.09	0.08	0.07	0.04	0.04	0.05
9	IT general & administrative expense	3.1.9	6.8	S 24-1	934	1.40	1.36	1.43	1.69	1.47	1.68	1.71	1.77
10	Building facility operations	3.1.10	6.9.2	S 23-1	935	2.86	3.15	3.13	3.03	3.15	3.30	3.57	3.70
11	Revenue requirement offset	3.1.11	6.10.3	S 24-2	941	(1.08)	(0.54)	(0.82)	(0.61)	(1.06)	(0.44)	(0.45)	(0.47)
12	Property and business taxes	3.1.12	8.1.0	S5-6	408.1	0.40	0.28	0.28	0.32	0.31	0.50	0.83	1.12
13	Total EDTI costs					16.90	19.67	19.29	21.31	18.98	19.35	20.10	20.85
14	Corporate services allocation	Appx K Table 7.1.3-5 r1		S25-3, r13,14,18,19 S25-2, r54,55		14.98	12.65	12.16	11.50	11.00	12.02	12.39	12.93
15	Total overhead pool					31.88	32.32	31.45	32.81	29.98	31.37	32.49	33.78
16	Total indirect support to capital from MOP	6.3.1-2		S 24-1	922	(1.90)	(1.91)	(1.78)	(2.00)	(0.78)	(0.81)	(0.83)	(0.86)
17	Net operating master overhead pool					29.98	30.41	29.67	30.81	29.20	30.56	31.66	32.92
18	Variance						(0.74)		(1.61)		1.36	1.10	1.26

Source: Exhibit 0003.00.EDTI-3539, application, Table 1.5.5.1-1 Costs Included in Master Overhead Pool 2011-2017 (\$ million), PDF pages 111-112 of 900.

280. EDTI determined the MOP rate in order to allocate MOP costs to operating activities in a multi-step process. EDTI confirmed that the allocation methodology applied to MOP has not changed from its previous GTA.

281. Table 18 below shows the 2013-2014 historical and 2015-2017 forecast labour and salary costs, distinguishing the labour and salary costs that are included and not included in the MOP:

Table 18. Labour and salary – Non-MOP and MOP

Description	Rows	C 2013 D	D 2013 A	E 2014 D	F 2014 F	G 2015 F	H 2016 F	I 2017 F
Labour and salary – D and T designated (non-MOP)		(\$ million)						
Distribution operating	1	33.25	32.59	33.60	33.60	35.42	36.65	37.89
Distribution capital	2	22.50	19.10	23.09	23.09	26.10	26.99	27.90
Distribution total	3 = 1 + 2	55.75	51.69	56.69	56.69	61.52	63.64	65.79
Transmission operating	4	8.64	8.75	9.58	9.58	10.28	10.83	11.05
Transmission capital (excluding AESO)	5	6.18	5.57	5.53	5.53	5.68	5.45	5.32
Transmission total	6 = 4 + 5	14.82	14.32	15.11	15.11	15.96	16.28	16.37
Total EDTI (excluding AESO directed)	7 = 3 + 6	70.57	66.01	71.81	71.81	77.48	79.92	82.16
Transmission capital (AESO)	8	0.60	0.84	0.66	0.66	0.91	0.99	2.31
Total EDTI	9 = 7 + 8	71.17	66.86	72.47	72.47	78.39	80.91	84.47
Labour and salary – MOP								
Total labour and salary	9	8.07	7.60	8.56	7.30	7.11	7.24	7.53
Allocation to Distribution operating	10	6.37	6.00	6.68	5.69	5.47	5.57	5.79
Allocation to Transmission operating	11	1.69	1.60	1.88	1.61	1.64	1.67	1.73
Labour and salary – Transmission								
Transmission operating	12 = 4 + 11	10.33	10.35	11.46	11.19	11.92	12.50	12.78
Transmission capital	13 = 5 + 8	6.78	6.42	6.19	6.19	6.59	6.44	7.63
Salary and labour charged to or from others	14	(1.44)	(0.44)	(0.89)	(0.50)	(0.21)	(0.12)	(0.73)
Total Transmission salary and labour	15 = 12+13-14	15.67	16.33	16.76	16.88	18.30	18.82	19.68

Source: Exhibit 0003.00.EDTI-3539, application, Table 1.5.5.2-1 Labour and Salary Non MOP and MOP (\$ million), with 2012 actual column removed. The "2014F" column indicates the forecast as applied-for by EDTI.

282. In the following table, the MOP rate (row 7) that is used to allocate the MOP costs to operating activities and capital projects is calculated by dividing the net MOP costs (row 3) by the labour and salary costs for operating activities that are not included in the MOP (rows 4 and 5), which yields a MOP rate of 69 per cent. As explained in EDTI's application although the rate is calculated late in the year, there may be differences between the forecast and actual amounts.¹⁹² Consequently there are small differences between line 17 of Table 17 and line 10 of Table 19 but the overhead rate is not affected.

¹⁹² Exhibit 0003.00.EDTI-3539, application, paragraph 269, PDF page 116 of 900.

Table 19. Master overhead pool for Distribution and Transmission

Description	Ref.	B 2013 D	C 2013 A	D 2014 D	E 2014 UF	F 2015 F	G 2016 F	H 2017 F
(\$ million)								
1 EDTI total master overhead pool	Ta 1.5.5.1-1, r15	32.26	31.45	33.65	32.43	32.03		
2 Less \$ allocated to capital overhead pool	Ta 1.5.5.1-1, r16	(1.91)	(1.78)	(2.00)	(0.78)	(0.81)		
3 Net MOP to be allocated		30.35	29.67	31.65	31.65	31.22		
Labour and salary								
4 L&S - Distribution operating	Ta 1.5.5.2-1, r1	33.25	32.59	33.60	33.60	35.42		
5 L&S - Transmission operating	Ta 1.5.5.2-1, r4	8.64	8.75	9.58	9.58	10.28		
6 L&S - Total EDTI (excluding AESO Direct)	r4 + r5	41.89	41.34	43.18	43.18	45.70		
MOP allocation								
7 MOP rate	r3 / r6	72%	72%	73%	73%	69%	69%	69%
8 Allocation to Distribution operating	r4 x r7	24.09	23.39	24.63	24.63	24.35		
9 Allocation to Transmission operating	r5 x r7	6.26	6.28	7.02	7.02	6.87		
10 Net MOP to be allocated		30.35	29.67	31.65	31.65	31.22		
MOP allocation percentage								
11 Distribution operating OH	r8 / r10	79%	79%	78%	78%	77%	77%	77%
12 Transmission operating OH	r9 / r10	21%	21%	22%	22%	23%	23%	23%
13 Total		100%	100%	100%	100%	100%	100%	100%

Source: Exhibit 0003.00.EDTI-3539, application, PDF page 116 of 900.

283. EDTI explained that distribution has not forecast the costs related to its specific operating cost categories for 2016 and 2017, because it is under PBR. As a result, EDTI was not able to calculate its 2016 and 2017 MOP rate using the same approach it used to calculate its 2015 forecasts. Therefore, EDTI assumed its 2016 and 2017 forecast MOP rate is equal to its 2015 MOP rate.¹⁹³

EDTI's capital overhead rate methodology

284. Indirect capital costs are allocated through the capital overhead pool. EDTI determined the capital overhead rates for 2015 by dividing the capital overhead pool costs by total capital expenditures for EDTI transmission and distribution, and stated that this method is consistent with the method used to calculate its 2012, 2013 and 2014 capital overhead rates. As with MOP, EDTI did not forecast distribution's operating and capital costs for 2016 and 2017 because distribution is under PBR. It was not able to calculate its 2016 and 2017 capital overhead rate forecast and it therefore used its 2015 forecast capital overhead rate for its 2016 and 2017 forecast capital overhead rates. Capital overhead pool costs and the total capital expenditures are trued up at the end of each year when the capital overhead rate is recalculated on an actual basis.¹⁹⁴

285. The following table provides a summary of the historical and forecast operating and capital overhead rates:

¹⁹³ Exhibit 0003.00.EDTI-3539, application, PDF page 117 of 900.

¹⁹⁴ Exhibit 0003.00.EDTI-3539, application, PDF page 119 of 900.

Table 20. EDTI historical and forecast operating and capital overhead rates 2013-2017

Service	B 2013 D	C 2013 A	D 2014 D	E 2014 F	A 2015	B 2016	C 2017
EDTI transmission function	72%	72%	73%	73%	69%	69%	69%
Regulated affiliates	72% + Cost Recovery Surcharge*	72% + Cost Recovery Surcharge*	73% + Cost Recovery Surcharge*	73% + Cost Recovery Surcharge*	69% + Cost Recovery Surcharge*	69% + Cost Recovery Surcharge*	69% + Cost Recovery Surcharge*
Unregulated affiliates & third parties	72% + Cost Recovery Surcharge*	72% + Cost Recovery Surcharge*	73% + Cost Recovery Surcharge*	73% + Cost Recovery Surcharge*	69% + Cost Recovery Surcharge*	69% + Cost Recovery Surcharge*	69% + Cost Recovery Surcharge*
MOP rate applied to capital labour and salaries	72%	72%	73%	73%	69%	69%	69%
Transmission capital overhead rate	8% ¹⁹⁵	9%	7%	7%	8%	8%	8%
AESO directed capital overhead rate	1%	1%	1%	1%	1%	1%	1%

*The applicability of the cost recovery surcharge is described in Appendix D-1-1.

Source: Exhibit 0003.00.EDTI-3539, Table 1.5.5-1, PDF page 110.

286. The CCA indicated that it is concerned with the significant increase in EDTI common costs, and costs from distribution (distribution costs) allocated to transmission. The following table, provided by the CCA in argument, compares the annual costs charged by corporate to EDTI transmission, either as direct charges or allocated; EDTI common costs for services, allocated to transmission; and costs allocated from EDTI distribution to transmission. Whereas the corporate costs are flat between 2012 and 2017, the CCA noted that the distribution costs increased by 67 per cent from 2013 and operating costs increased by 41 per cent.¹⁹⁶

Table 21. Comparison distribution and corporate costs allocated to EDTI transmission

	2012 A	2013 A	2014 UF	2015 F	2016 F	2017 F	Increase
	(\$ million)						
Direct corporate charges to EDTI -Transmission	0.64	0.81	0.86	0.98	0.99	0.96	
Corporate costs allocated to EDTI - Transmission	5.20	4.35	4.58	4.52	4.69	4.86	
Total costs from corporate	5.84					5.82	0%
EDTI common costs allocated to EDTI - Transmission	2.50	3.18	3.45	3.59	3.7	3.83	
EDTI – Distribution costs allocated to EDTI - Transmission	3.72	4.69	5.0	4.96	5.78	6.53	
Total costs shared or from Distribution	6.22					10.36	67%
Transmission costs directly incurred – operating	10.02	11.45	12.09	14.56	13.89	14.14	41%

Source: Exhibit 3539-X0194, CCA argument, paragraph 59.

287. EDTI explained it has not provided the reasons for the annual increases from 2014 to 2017 in capital and operating labour and salary costs related to distribution because it is currently under PBR. EDTI indicated that it would take a significant amount of time and effort to prepare

¹⁹⁵ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-113(c), 2013 approved capital overhead rate in Decision 2014-269 was eight per cent rather than the six per cent.

¹⁹⁶ Exhibit 3539-X0194, CCA argument, paragraph 59.

this information for distribution.¹⁹⁷ In its IR response, EDTI referred to PBR requirements and stated:

Under PBR, utilities are incented to minimize their operating costs, subject to maintaining reliability. The Commission has concluded that PBR provides strong financial incentives to ensure that utilities minimize their operating costs subject to maintaining service quality and reliability requirements, which should give the Commission significant comfort that, consistent with these incentives, EDTI's distribution function budget/forecast is reasonable and prudent.

As a result, the Commission can rely on the proposed MOP and capital overhead rates for the Test Period without the need to test EDTI's distribution function forecast.¹⁹⁸

288. The CCA argued that the Commission should place no reliance on EDTI's submissions. To the contrary, distribution has every incentive to move costs from distribution, which is capped by I-X, to transmission which is not capped under cost of service regulation. Cross-subsidization between transmission as a cost of service regulated function and distribution, which is regulated by incentives under PBR, may exist. The CCA asserted that roughly a \$4 million increase in costs is unexplained. EDTI's common costs, which constitute a significant portion of EDTI transmission's O&M costs, have not been subject to rigorous examination with budgetary input and support or justification from EDTI distribution but rather, have been developed independent of EDTI distribution. The CCA recommended that in future proceedings, a detailed analysis of the allocation of EDTI's common costs by all functions be provided for each of the test years reflecting not only transmission's budget, but also distribution's budget.¹⁹⁹

289. EDTI stated that its MOP and capital overhead methodologies are consistent with those used by EDTI in the past and produce reasonable forecast allocations over the 2015 to 2017 test period.²⁰⁰

290. EDTI argued that requiring it to file distribution related financial information goes far beyond what the Commission has required distribution utilities to file on an ongoing basis under PBR. The Commission determined specifically that utilities are not required to file minimum filing requirement and general rate application schedules under PBR.²⁰¹ Further, PBR is intended to reduce regulatory burden for all parties. The CCA's recommendation is contrary to the purposes and objectives of PBR.²⁰²

291. EDTI also asserted that the CCA's presentation of numbers that purportedly demonstrate a sharp increase in shared and allocated costs is inaccurate and misleading. Table EDTI-AUC-2015FEB06-004-6²⁰³ provided a summary of EDTI transmission costs by source for its 2012 actuals to 2017 forecast. The table demonstrates that the costs allocated from distribution to transmission, as a proportion of the transmission revenue requirement, are similar. As shown in row 4, 2012-2014 ranges from 5.3 to 6.6 per cent; 2015-2017 ranges from 4.9 to 6.1 per cent.

¹⁹⁷ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-022, PDF page 91.

¹⁹⁸ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-009, PDF page 58.

¹⁹⁹ Exhibit 3539-X0194, CCA argument, PDF pages 23-24 of 42.

²⁰⁰ Exhibit 3539-X0193, EDTI argument, PDF page 46 of 259.

²⁰¹ Decision [2012-237](#): Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012, paragraph 863.

²⁰² Exhibit 3539-X0197, EDTI reply argument, PDF page 41 of 80.

²⁰³ Exhibit 3539-X0005, PDF page 39.

Further, EDTI pointed out that the CCA's numbers do not account for the increases over the period in the costs allocated from distribution to transmission as a result of the 2013 EUI Corporate Services reorganization or asset usage fees relating to the work centre redevelopment project, which will commence in 2015. There is also no consideration given to growth on EDTI's transmission system over this five-year period. The exclusion of corporate services costs in the CCA's analysis results in a flawed "apples-to-oranges" comparison.²⁰⁴

292. EDTI reproduced Table EDTI-AUC-2015FEB006-004 in order to provide a comparison of the increase in the costs allocated to distribution and the increase in directly incurred transmission operating costs. EDTI stated that the table shows that the total growth in the amounts from 2012 actual to 2017 forecast is 34.1 per cent, which is lower than the growth in transmission's operating costs of 41 per cent over the same period, as cited by the CCA. This demonstrates that the allocated costs to transmission have, in fact, grown at a lower rate compared to transmission's directly incurred operating costs. Additionally, if the impact of the increase in net asset usage fees related to the work centre redevelopment project is removed from the increase, the remaining increase is 19.9 per cent over the 2012-2017 period, with inflation (assuming a three per cent annual escalation rate) representing the majority of the 19.9 per cent increase over the 2012-2017 period.²⁰⁵

293. EDTI argued that there is no reasonable basis for the CCA's recommendation and the CCA has mischaracterized the evidence on the record. When properly analyzed, the record demonstrates that there is no basis for claiming that there is any cross-subsidization of distribution by transmission. EDTI asserted that "the potential for cross-subsidization is not possible within EPCOR, due to factors such as EDTI's rigorous bottom-up budgeting approach in preparing both its distribution and transmission forecasts, its rigorous budget approval process, code of conduct rules against cost subsidization, professional codes of ethics which apply to individual staff members, auditor reviews and annual [Rule 005](#)^[206] filings."²⁰⁷

Commission findings

294. EDTI shares three types of common costs:

- common field operations costs, incurred by distribution and charged to transmission through asset usage fees or allocators, which are primarily activity-based and are primarily on a forecast basis
- MOP costs, allocated as the proportion of direct labour costs incurred to indirect general and administrative labour costs
- capital overhead costs, allocated as the proportion of direct capital labour costs to capital expenditures on a forecast basis

²⁰⁴ Exhibit 3539-X0197, EDTI reply argument, PDF pages 37-38 of 80.

²⁰⁵ Exhibit 3539-X0197, EDTI reply argument, PDF page 40 of 80.

²⁰⁶ Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

²⁰⁷ Exhibit 3539-X0197, EDTI reply argument, paragraph 110, PDF page 42 of 80.

295. The Commission has reviewed the allocators, used for services provided by EDTI to its affiliates in Appendix D-1-2,²⁰⁸ common field operations between EDTI transmission and distribution in Appendix D-1-4,²⁰⁹ and asset usage fees in Appendix D-1-5.²¹⁰

296. The Commission recognizes that EDTI continues to use forecast allocators associated with services provided by EDTI to its affiliates and common field operations between EDTI transmission and distribution, instead of relying on historical information. The Commission recognizes that at the time of its 2013 reorganization, EDTI may not have had sufficient historical information on which to base allocators and therefore adopted the use of forecast costs for its allocators. For the purpose of this application, the Commission finds the allocators and underlying methodologies proposed by EDTI to be reasonable.

297. However, now that EDTI has some historical information, the Commission considers for comparative purposes it would be useful for EDTI to provide historical information for its allocators of common costs. EDTI is directed to provide in its next GTA, an analysis which compares the utilization of historical and forecast allocators, including a detailed justification as to why a forecast allocator or historically-based allocator provides better information for the allocation of costs for each service.

298. With respect to MOP and capital overhead, in Decision 2014-269, the Commission concluded that the methodology to allocate MOP costs and capital overhead costs resulted in a reasonable allocation of costs to distribution and transmission for the test period. The costs included in, and the forecasting methodology applied to, the MOP allocators remains relatively unchanged since EDTI's last GTA. With regard to the 2016 and 2017 test years, EDTI stated it was not able to calculate its 2016 and 2017 forecast MOP and capital overhead rates because it lacked detailed operating and capital costing information from distribution, as a result of PBR. Similarly, the costing information used in the capital overhead rate and MOP rate calculations for 2015 included distribution information. Due to PBR, the distribution information has not been tested or approved by the Commission.

299. The Commission finds that the underlying MOP and capital overhead methodologies remain reasonable. However, the Commission agrees with the CCA that the absence of any detailed costing information from distribution used in determining the forecast MOP and capital overhead rates raises concerns of potential cross-subsidization between distribution and transmission.

300. Given the lack of operating and capital costing information from distribution, the Commission is not persuaded that there is sufficient information to justify the change in capital overhead and MOP rates forecast for the 2015-2017 test years. As a result, the Commission directs EDTI to revise its forecast MOP rate and capital overhead rates to be consistent with the rates approved in Decision 2014-269, adjusted to include any change associated with the capitalization of STI costs. EDTI, in its compliance filing, is directed to explain any impact to MOP rates and capital overhead rates because of the change in the capitalization of STI costs for the test years. EDTI is also directed to describe the accounting for the STI costs from labour accounts through intermediate overhead accounts to capital accounts.

²⁰⁸ Exhibit 0022.00.EDTI-3539.

²⁰⁹ Exhibit 0024.00.EDTI-3539.

²¹⁰ Exhibit 0025.00.EDTI-3539.

301. Further, the Commission considers that requiring distribution to file costing information that is used to forecast shared services costs, MOP costs and rates, and capital overhead rates for transmission is not inconsistent with the PBR scheme. In Decision 2012-237,²¹¹ the Commission stated the following regarding distribution function filing requirements:

863. For a company under PBR, the requirement to file the AUC Rule 005 schedules in both its annual PBR rate adjustment filing and a separate AUC Rule 005 application, does not exempt the company from its obligation to maintain detailed accounts in accordance with the acts, regulations, Commission rules, or Commission decisions applicable to the company. Therefore, unless otherwise directed or exempted by the Commission, the companies are directed to maintain the ability to file a complete set of MFR and GRA schedules with actual results for all years within the term of the company's PBR plan. The companies are not required, however, to file a complete set of MFR and GRA schedules annually.²¹²

302. Consistent with Decision 2012-237, the onus resides with the applicant to justify its costs included in its GTA. Accordingly, the Commission directs EDTI transmission to file distribution related information in its next GTA to support transmission forecasts.

7.6 Corporate services costs

303. Corporate services costs are based on a shared services model and are recovered by EUI from EDTI through either direct assignment of costs, or an allocation process. Where applicable, service level agreements also deal with fees relating to assets owned by the service provider that are used in providing service to the service recipient. These fees are referred to as asset usage fees or corporate asset usage fees for assets owned by EUI, and affiliate asset usage fees for assets owned by EDTI or one of its affiliates.

304. In Decision 2012-272, the Commission directed an across-the-board nine per cent reduction in allocated corporate services costs.

305. As a result, EUI, EDTI and EEA completed an assessment of EPCOR's corporate services delivery model and cost levels, and restructured EUI's corporate services departments (2013 reorganization). The 2013 reorganization resulted in the elimination of a total of 62 corporate services positions as a result of cost cutting measures or efficiencies realized within corporate services departments. In Decision 2014-269, the Commission approved EDTI's corporate services costs as filed.

306. For the 2015-2017 test period, EDTI stated in its application that EUI's corporate services functions retain the organizational structure resulting from the 2013 reorganization, with the exception of the recentralization of the human resources function (the HR reorganization). As part of an ongoing monitoring and review of corporate services departments and functions, EUI transferred seven equivalent headcounts from EDTI and another business unit back to human resources, re-establishing the centralized service model for human resources that existed prior to the 2013 reorganization. EDTI indicated that the HR reorganization resulted in a net zero increase in equivalent headcount.

²¹¹ Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

²¹² Decision 2012-237, page 186.

307. The table below provides the historical and forecast corporate administration and general costs for EDTI transmission:

Table 22. EDTI corporate administration and general costs updated 2015-2017

USA Account	Description	2012 actual	2013 decision	2013 actual	2014 decision	2014 updated forecast	2014 actual	2015 forecast	2016 forecast	2017 forecast
		(\$ million)								
	Transmission									
930.2	Miscellaneous general expenses	4.11	3.48	3.54	3.94	3.75	3.44	3.31	3.37	3.52
931.1	Head office rent	0.49	0.50	0.50	0.38	0.42	0.35	0.41	0.45	0.49
934	IT G&A expense	0.61	0.61	0.55	0.65	0.60	0.57	0.67	0.70	0.70
930.2	Asset usage fee (allocated dep'n & return)	0.87	0.74	0.82	0.70	0.79	0.76	0.82	0.89	0.89
	Total	6.07	5.33	5.40	5.66	5.55	5.12	5.21	5.41	5.60
941	Less disallowed/non-utility costs									
	Community investments	(0.20)	(0.28)	(0.42)	(0.58)	(0.48)	(0.52)	(0.38)	(0.39)	(0.41)
	At risk compensation	(0.50)	(0.20)	(0.37)	(0.32)	(0.32)	(0.40)	(0.18)	(0.19)	(0.20)
	Corporate disallowance	-	(0.07)	-	-	-	-	-	-	-
	Corporate cost module	-	-	-	-	-	-	-	-	-
	Rent for EPCOR Tower	(0.07)	(0.06)	(0.07)	(0.06)	(0.06)	(0.05)	(0.06)	(0.06)	(0.06)
	Business development	(0.09)	(0.07)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)
	CPC	0.00	(0.10)	(0.12)	(0.06)	(0.05)	(0.05)	(0.02)	(0.02)	(0.02)
	Subtotal	(0.86)	(0.79)	(1.04)	(1.08)	(0.97)	(1.07)	(0.70)	(0.72)	(0.74)
	Total corporate G&A allocated to Transmission	5.20	4.55	4.35	4.58	4.58	4.05	4.52	4.69	4.86

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 25.1.

Commission findings

308. The Commission has reviewed the corporate services provided to EDTI, the allocation methodologies for determining the allocation factors and the application of those factors, including the composite cost allocator and forecast asset usage fees ascribed to EDTI. For 2015, 2016 and 2017, EUI's corporate cost allocation reflects the same approach used in EDTI's 2013-2014 application, which was approved by the Commission in Decision 2014-269.

309. The Commission is satisfied that the recentralization of the HR function back into EUI is reasonable because it addresses the negative feedback associated with a decentralized model for the HR function, while having no impact on the level of required HR FTEs. In response to a Commission IR, EDTI provided the following statement regarding the feedback from management regarding the services provided by HR:

The feedback from management prior to the 2014 HR Reorganization primarily focused on a perceived lack of effectiveness in carrying out the functions embodied in HR Labour Relations and Talent Management under the decentralized model. For example,

recentralizing Labour Relations was seen as improving coordination of effort and management of the collective bargaining process and agreements....²¹³

310. The Commission finds that re-centralizing these HR functions has no material cost impact to EDTI transmission, which is supported by lower HR costs than were approved by the Commission for the 2014 test year, as shown in the table below:

Table 23. Total HR related costs for EDTI transmission

	A 2014 D	B 2014 UF	C 2015 F	D 2016 F	E 2017 F
	(\$ million)				
1 Corporate HR costs allocated to EDTI's shared services	1.35	1.89	2.13	2.20	2.28
2 Less payroll function	-	0.28	0.30	0.31	0.32
3 Subtotal of corporate human resources costs	1.35	1.61	1.83	1.89	1.96
4 HR related costs embedded in EDTI	1.24	0.54	0.37	0.39	0.41
5 Total HR costs included in EDTI	2.59	2.15	2.20	2.28	2.37
EDTI's Transmission function					
6 MOP allocation rate	22%	22%	23%	23%	23%
7 Allocation of HR costs using MOP Allocation Rate (r3xr7)	0.30	0.35	0.42	0.43	0.45
8 HR related costs embedded in EDTI's transmission function	0.27	0.12	0.09	0.09	0.09
9 Total HR costs included in EDTI's transmission function (r8+r9)	0.57	0.47	0.51	0.52	0.54
10 Reduction in costs to Transmission		(0.10)	(0.06)	(0.05)	(0.03)

Source: Exhibit 3539-X0005, EDTI-AUC-2015FEB06-005-1Total HR related costs for EDTI's Transmission function.

311. EDTI's corporate services costs and underlying allocation methodology are approved as filed, subject to the Commission's determinations with respect to:

- corporate development costs (Section 7.6.1)
- allocation of sell-down and shelf prospectus costs related to Capital Power Corporation (Capital Power) (Section 7.6.2)
- allocations to the Heartland project (Section 7.6.3)
- allocation of EPCOR Tower rental costs (Section 7.6.4)

7.6.1 Corporate development costs

312. In its application, EDTI forecast corporate development costs allocated to transmission based on its composite cost allocator, to be \$0.08 million annually for the 2015-2017 test periods. EDTI described the services provided by EPCOR's corporate development department as follows:

Services provided by the Corporate Development department involve development of growth strategies and opportunities conducive to ensuring the long term sustainability of

²¹³ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-005(e).

the EPCOR group's businesses in the face of changing business environments. Corporate Development enables EDTI to provide safe, reliable, and economic utility service by developing growth and diversification options to support the EPCOR group's larger strategic plan.²¹⁴

313. EDTI argued that corporate development costs should be approved for inclusion in its forecast revenue requirement.

314. Similar to forecast costs for business development, the UCA recommended that corporate development costs related to the development of the EPCOR group should be excluded from revenue requirement.²¹⁵

Commission findings

315. In EDTI-AUC-2015FEB06-020,²¹⁶ EDTI explained the benefits that customers receive from the efforts of the corporate development department, as follows:

EDTI's ability to provide safe, reliable and economic utility service is enhanced through the growth and diversification of the EPCOR group in a number of ways. For example, as the EPCOR group grows through acquisitions and the implementation of partnerships, joint ventures, etc. (all of which are identified and implemented through the work performed by Corporate Development), EDTI is afforded the opportunity to improve its operations through exposure as a member of the EPCOR group to best practices from the acquired entities, partners, joint ventures, etc. and their business operations. As the EPCOR group grows through the efforts of the Corporate Development department, EDTI's utility operations also benefit through Corporate Services cost reductions resulting from increased economies of scale (i.e., Corporate Services costs are spread across a larger base, reducing allocated Corporate Services costs to EDTI and customer rates).

316. Although the Commission recognizes that there may be potential benefits to utility customers arising from the work performed by the corporate development department, the Commission is not persuaded that these costs are directly related to the provision of electric transmission utility service. Further, EDTI failed to quantify and justify any cost reductions that may arise from the growth and diversification of the EPCOR group. For these reasons, EDTI is directed to remove corporate development costs allocated to EDTI transmission in its compliance filing.

7.6.2 Allocation of sell-down and base shelf prospectus costs related to Capital Power Corporation (Capital Power)

317. Within the Treasurer-Corporate finance function, which performs the services associated with raising capital, primarily through the issuance of debt necessary to finance EDTI's, EEA's and other EPCOR subsidiaries' capital expenditures and working capital requirements, EDTI has forecast costs associated with the sell-down of Capital Power and base shelf prospectus.

318. In rebuttal evidence, EDTI stated that the total 2015 forecast amount related to the 2015 base shelf prospectus and the Capital Power sell-down amounts is \$0.43 million; and the total

²¹⁴ Exhibit 0003.00.EDTI-3539, EDTI application, paragraph 1692, PDF page 581 of 900.

²¹⁵ Exhibit 3539-X0192, UCA argument, paragraph 54, PDF page 14 of 22.

²¹⁶ Exhibit 3539-X0005, PDF page 88 of 513.

2017 forecast amount related to the 2017 base shelf prospectus is \$0.36 million. There are no costs associated with this activity in the 2016 forecast revenue requirement.

319. In response to EDTI-AUC-24 2015FEB06-019, EDTI confirmed that transmission's share of the base shelf prospectus renewal costs and the costs associated with the sell-down of Capital Power are approximately \$0.04 million, which is included in the 2015 forecast revenue requirement. The transmission share of the 2017 base shelf prospectus renewal costs are approximately \$0.03 million, which is included in the 2017 forecast revenue requirement, with no Capital Power sell-down costs forecast for 2017.²¹⁷

320. The UCA did not dispute that the sell-down of Capital Power raised funds, but the UCA argued that the extent to which those funds were used for utility investment was a matter entirely within the discretion of EUI and its shareholder, and to the sole benefit of the shareholder. The UCA argued that customers should not pay costs relating to activities undertaken for the sole benefit of the utility shareholder.²¹⁸ In support of its view, the UCA stated that the Commission has consistently made rulings upholding this principle, and Mr. Bell provided in his written evidence an example from Decision 2012-272 relating to the disallowance of business development costs,²¹⁹ where the Commission stated, at paragraph 413:

413. The Commission agrees with the position put forward by the UCA and the CCA that business development costs are not related to the provision of utility service. Business development costs relate to the growth within the EPCOR group of companies not EDTI and EEAI and therefore should not be included in the corporate services costs allocated to EDTI and EEAI. The Commission finds that the argument for including the business development costs put forward by EDTI that there will be potential future benefits from economies of scale acknowledges that there is no current benefit from these services to EDTI and EEAI and, therefore, the costs are not currently required for the provision of utility service.

321. In rebuttal evidence, EDTI explained that the shelf prospectus is completely unrelated to the Capital Power sell-down and is required for EUI to raise funds through the issuance of public debt. The funds are used to finance EUI's various business units, including EDTI. It is wholly reasonable and consistent with past Commission approvals, that EDTI should bear its share of the costs of these activities that are undertaken in part for its benefit. Mr. Bell is incorrect that the sell-down of Capital Power does not benefit EDTI. The sell-down of Capital Power is an additional method for EUI to raise funds for investment, very similar to the issuance of debt. EUI lends these funds to the various business units, including EDTI, for their capital requirements. EDTI argued that it is reasonable to include these costs in transmission revenue requirement because this is a mechanism that EUI uses to raise funds to support its 25 various business units, including transmission.²²⁰

322. In reply argument, EDTI submitted that the funds raised through these sell-downs are fundamentally no different from funds raised by EUI in the debt market. Both of these types of funding form part of the pool of funds that EUI has available to it to fund the utility investments of the EPCOR group of companies. As the holder of this pool of funds, EUI controls both the funds raised in the debt market and funds raised through Capital Power related sell-downs and

²¹⁷ Exhibit 3539-X0071, EDTI rebuttal evidence, PDF pages 45-46 of 82.

²¹⁸ Exhibit 3539-X0192, UCA argument, PDF page 13 of 22.

²¹⁹ Exhibit 3539-X0192, UCA argument, PDF pages 13-14 of 22.

²²⁰ Exhibit 3539-X0071, EDTI rebuttal evidence, PDF page 46 of 82.

ultimately determines their use. EUI is the funding source for all of its subsidiaries' capital requirements, both debt and equity, including EDTI. As such, there is fundamentally no difference between the costs incurred by EUI with respect to a sell-down of its financial interest in Capital Power and a base shelf prospectus supporting EUI debt offerings. Both are incurred for the purpose of enabling EUI to raise money to fund its subsidiaries' utility investment, and both are properly allocated to the subsidiaries, including EDTI, that obtain their financing from EUI.²²¹

Commission findings

323. With respect to the inclusion of costs related to the base shelf prospectus, the Commission accepts EDTI's explanation that EUI has established and maintained access to public debt capital as a means of raising long-term debt financing by filing a short-term base shelf prospectus.²²² The Commission finds that the inclusion of base shelf prospectus costs is required for EPCOR to access debt markets to fund its business units, including EDTI transmission. Therefore, the Commission approves EDTI's forecast base shelf prospectus costs that are allocated to EDTI transmission for the test period.

324. Although the sell-down of EUI's financial interest in Capital Power provides EUI with access to funds that could potentially be used for EDTI transmission, the Commission agrees with the UCA that the sell-down of Capital Power is entirely within the discretion of EUI and its shareholder. EDTI's cost of debt is determined on a stand-alone basis, by which the cost of debt is representative of the cost at which it could have obtained debt in the marketplace. Hence, the source of funds loaned to EDTI does not affect the cost of debt to EDTI. EDTI is directed to remove the forecast costs of the Capital Power sell-down from its revenue requirement for the test period, in its compliance filing to this decision.

7.6.3 Allocations to the Heartland project

325. In Table EDTI-AUC-2015FEB06-030-2,²²³ EDTI provided the forecast revenue requirement related to the Heartland project:

Table 24. Heartland project revenue requirement

Description	A 2013	B 2013	C 2014	D 2014 UF	E 2015 F	F 2016 F	G 2017 F
	(\$ million)						
1 Return on equity	3.56	3.71	7.04	8.13	8.46	8.27	8.08
2 Return on debt	2.52	3.67	5.00	7.46	8.09	8.08	7.94
3 Depreciation	2.41	2.52	4.81	5.33	5.64	5.64	5.64
4 Operating costs (not including linear taxes)	-	-	0.07	0.05	0.13	0.10	0.10
5 Linear taxes	-	-	-	-	0.19	0.20	0.21
6 Corporate cost allocations	0.77	0.77	0.85	0.85	0.68	0.70	0.73
7 Revenue requirement	9.26	10.67	17.77	21.82	23.19	23.00	22.71

Source: Exhibit 3539-X0005, EDTI-AUC-2015FEB06-030-2.

²²¹ Exhibit 3539-X0197, EDTI reply argument, PDF pages 46-47 of 80.

²²² Exhibit 3539-X0012, EDTI-CCA-2015FEB06-030(b).

²²³ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-030-2.

326. In the hearing, EDTI noted that the Commission questioned the allocation of corporate services costs to the Heartland project given the contributions paid to AltaLink for the Heartland project and the 50/50 ownership arrangement between EDTI and AltaLink. In response, Mr. Chaudhary, on behalf of EDTI, explained why the contribution should attract a full allocation of corporate services costs:

Q. And I guess that impacts the allocations you're going to get on your corporate services as if you had that extra amount of assets, but essentially, it seems to me, you're going to be doing virtually nothing. Having made the contribution, the assets are AltaLink's. They'll do all the work associated with those assets. So should there be some adjustment made to your allocation procedures to take into account that you have a large amount of assets for which you have no responsibilities, other than you indicated financing. And I believe they've already been financed.

A. MR. CHAUDHARY: So, Commissioner Holgate, the costs of the -- I guess the PP&E, as well as the contribution, represents the costs that EDTI had incurred to acquire the assets that are in EDTI's territory. So I don't feel that we should make a distinction between, you know, the dollar value that we've outlaid in regards to the physical asset versus the dollar value that, you know, we've attributed to the contribution to keep the project 50-percent split between EDTI and AltaLink. So I don't think we need to or we should make a separate allowance in the corporate allocations for the contributions. As my colleague, Ms. Zrobek reminded me, is that the corporate allocations attributable to PP&E relate to the governance function and on an ongoing basis EDTI and EPCOR, you know, need to monitor or maintain their assets. And the assets, as well as, I guess, the related contribution as part of the Heartland project, would fall into that. So it would be, I guess, not unlike our CPC corporate allocations.²²⁴

327. EDTI asserted that consistent with the Commission's partitioning approval in Decision 2014-160,²²⁵ the contribution had the effect of increasing the value of the asset on EDTI's books to reflect its intended 50 per cent ownership interest in the line, while reducing the value of the asset on AltaLink's books by a corresponding amount.²²⁶

328. EDTI argued that the full asset value recorded on EDTI's books, i.e., including the contribution amount, should attract corporate services costs. If the contribution amount is not afforded this treatment, then a substantial portion of the total value of the asset on the utility's books will not attract appropriate corporate governance costs on either the EDTI or AltaLink sides. In addition, as noted by the witnesses, the contribution amount is similar in nature to EUI's passive financial investment in Capital Power, which the Commission directed in Decision 2012-272 be allocated a full portion of EUI corporate services costs under EUI's corporate services cost allocation model. It would be inconsistent with this Commission direction to deny such treatment in relation to EDTI's Heartland project contribution, having previously required that EUI's passive financial investment in Capital Power attract a full allocation of corporate services costs.²²⁷

²²⁴ Transcript, Volume 5, pages 882-883.

²²⁵ Decision 2014-160: AltaLink Management Ltd. and EPCOR Distribution & Transmission Inc., Partitioning of Heartland Transmission Lines, Proceeding 2932, Application 1610091-1, June 6, 2014.

²²⁶ Exhibit 3539-X0193, EDTI argument, PDF pages 110-111 of 259.

²²⁷ Exhibit 3539-X0193, EDTI argument, PDF pages 110-111 of 259.

Commission findings

329. In paragraph 263 of Decision 2014-269, the Commission described the Heartland project, the partitioning agreement, and the impact on rate base, as follows:

263. The Heartland project was developed as a joint venture between AltaLink and EDTI, but EDTI has recently received approval, in Decision 2014-160,¹⁸⁸ for its transmission service area ownership structure, which EDTI submits preserves its tax exempt status.¹⁸⁹ Under the approved structure, AltaLink operates and maintains the transmission line. In Decision 2014-160, the Commission noted that EDTI and AltaLink provided an explanation of the unique ownership structure of the Heartland project, the obligations of each utility, and impact of the partition agreement on rate base and revenue requirement:

25. In response to the Commission's information requests regarding the allocation of day-to-day management responsibilities of the Heartland transmission line between AltaLink and EDTI, the applicants submitted that under the SA structure, each of AltaLink and EDTI would continue to be designated as the holder of the permit and licence issued with respect to portions of the Heartland transmission line lying within each TFO's service area. Further, each TFO would therefore continue to be subject to all the rights and obligations that come with holding a permit and licence. The applicants stated that under the commercial arrangements between AltaLink and EDTI, AltaLink and EDTI would each be directly involved in governance functions relating to the line. Finally, the applicants submitted that each of AltaLink's and EDTI's respective capital investments in the Heartland transmission line would be included as capital expenditures ultimately reflected in each TFO's rate base.

...

28. Regarding Section 5.03 of the Partition Agreement discussing proportionate costs and Section 5.04 of the agreement discussing the regulatory treatment of cost differences, the UCA issued information requests to confirm that there would be no return related to any contributions received by AltaLink and EDTI related to this agreement. In response, the applicants confirmed that sections 5.03 and 5.04 of the Partition Agreement would result in AltaLink and EDTI each adding equal amounts before Allowance for Funds Used During Construction to their respective rate bases. Further, the applicants submitted that in the event that a contribution is paid from EDTI to AltaLink, EDTI would increase its rate base by the amount of the contribution. At the same time, AltaLink's rate base would be reduced by the same amount and the capital costs to ratepayers would remain the same.¹⁹⁰

¹⁸⁸ Decision 2014-160: AltaLink Management Ltd. and EPCOR Distribution & Transmission Inc. Partitioning of Heartland Transmission Lines, Proceeding 2932, Application 1610091-1, June 6, 2014.

¹⁸⁹ To ensure that EDTI's tax exempt status is maintained after the Heartland transmission line begins generating revenue, EDTI must ensure that its portion of income from the line is from sources within its geographical boundaries of the City of Edmonton.

¹⁹⁰ Decision 2014-160, PDF pages 7-8.

330. Given the Commission's previous directions and the submissions from parties, the Commission agrees with EDTI that it would be inconsistent to deny the allocation of corporate

services costs to the Heartland project because of the unique ownership structure and that the contributions should attract a full allocation of costs. Accordingly, the Commission finds the allocation of corporate services costs to the Heartland project to be reasonable and these costs are approved, as filed, subject to any necessary adjustment as a result of the AltaLink DACDA decision in Proceeding 3585.

7.6.4 Allocation of EPCOR Tower rental costs

331. EDTI's supply chain management (SCM) corporate services include rent associated with EPCOR's corporate services departments and business units that are located in EPCOR Tower. EDTI noted that SCM corporate services costs remain the same as in the 2013-2014 GTA, with the exception that beginning in 2015, contracted security costs for the EPCOR Tower will now reside in the security cost category, to simplify the monitoring and management of these costs. The table below includes the historical and forecast costs for SCM corporate services:

Table 25. SCM corporate services 2012-2017

Description	2012 A	2013 D	2013 A	2014 D	2014 UF	2015 F	2016 F	2017 F
	(\$ million)							
EUI Total	8.29	7.22	6.81	4.63	4.99	5.25	5.80	6.26
EDTI (%)	34.0%	32.7%	33.4%	32.1%	31.5%	33.9%	33.9%	33.9%
EDTI	2.82	2.36	2.27	1.49	1.57	1.78	1.97	2.12

Source: Exhibit 0003.00.EDTI-3539, Table 7.3.1.1.10-1 SCM Corporate Services 2012-2017, PDF page 448 of 900.

332. In the application, EDTI explained the increases in EUI's SCM corporate services are allocated through EUI's composite cost causation allocator (of which 33.9 per cent is allocated to EDTI), have increased due to several factors. The increase of \$0.26 million from 2014 updated forecast to 2015 forecast and the \$0.54 million increase from the 2015 forecast to the 2016 forecast are primarily due to increases in the allocations of the square footage to corporate, relative to other business units, and inflationary increases in operating costs related to EPCOR Tower due to higher forecast property taxes. The change from the 2016 forecast to the 2017 forecast is primarily due to a \$0.27 million increase reflecting the full year impact of EDTI moving out of EPCOR Tower in 2015 and a \$0.19 million increase due to forecast inflationary increases in operating costs for EPCOR Tower primarily because of higher forecast property taxes.²²⁸

333. SCM corporate services costs are included in the MOP and then allocated between transmission and distribution.

334. The CCA noted that allocated rent costs to EDTI are increasing because one of the business units is moving employees from EPCOR Tower to Rosedale midway through 2015. However, the CCA argued that this is inconsistent with various statements made during the hearing from EDTI's witnesses which included:

- the space will be repurposed to the extent possible.
- We're not a hundred percent sure [what will happen] just yet. we are looking at moving another business unit into that area. The filing as it – or the application as it sits has that space going back into the corporate space.

²²⁸ Exhibit 0003.00.EDTI-3539, application, PDF pages 449-450 of 900.

- So we're not exactly sure whether it's going to be a business unit or another shared service group that moves in. So the space may be allocated to a corporate -- to a corporate group that has additional space requirements.
- We [EUI corporate] will do our best to use the space.²²⁹

335. The CCA submitted that it is not reasonable for EDTI to be required to pay more for the same space due to changes outside its control. Essentially, EDTI is stating that since a tenant is moving out all other tenants have to pick up the vacated space costs.²³⁰

336. Given the unclear record on this issue as to what is going to happen with the space and the fact that the space may in fact not be vacant during the test period, the cost increases to EDTI should be reduced by the amount attributed to the vacant space.²³¹ Alternatively, the CCA recommended that costs should be reduced on the grounds that there is no evidence of any incentive for EUI to control rent costs and occupancy rates.

337. The CCA referred to the fact that the Commission asked for comparable rental prices for properties similar to EDTI's current space. The response provided by EDTI related to the 2014 asking price, not actual prices of \$25 to \$40 per square foot and operating costs of \$15.17 to \$19.71 per square foot for 2014. EDTI's actual costs are at, or well above these costs. EDTI is forecasting \$39 base costs and operating costs of \$19.64 for 2015, which increase to \$23.77 in 2017. Both base and operating costs are at the high end of the asking prices. However, the CCA is particularly concerned with operating costs as they are increasing at a significant rate. The 2014 updated forecast operating costs were \$17.24. The operating costs for 2017 are \$23.77, which represents a 38 per cent increase in operating costs over three years. Given the large divergences from the already limited market data provided by EDTI, the CCA recommends that the operating costs for 2015-2017 be held to the 2014 updated forecast rate plus inflation.²³²

338. EDTI argued that the record shows that the overall costs associated with EPCOR Tower rent will decrease from the 2015 forecast to the 2016 forecast by \$0.09 million as a result of the work centre redevelopment project. With respect to the space that will be vacated by business unit personnel moving out of EPCOR Tower, which will constitute less than a single floor in the Tower, Ms. Zrobek noted that the space will be used in a number of ways:

We've found, since we've been there, that we seem to expand and retract pretty regularly. So we have to be fairly fluid in our requirement. So, as mentioned, the Rosedale building is supposed to be available at the middle -- like shortly. So the water folks may be vacating a portion of their space that they have.

EDTI may be using a portion of that space, as swing space, while they're doing work at their new service centre. So we are going to try to accommodate that. From time to time the corporate groups, depending on the projects that they have in place, will require additional space. So if you have a large IT project underway and you are using a lot of contractors to get that done, they'll need seating. So sometimes we use that.

We might be able to go back through that area and reclaim some of the space for some additional breakout rooms and some meeting rooms. So that was the area that when we condensed ourselves and sublet the two floors, we lost a lot of meeting rooms and

²²⁹ Exhibit 3539-X0194, CCA argument, PDF pages 24-25 of 42, citing Transcript, Volume 1, pages 29-32.

²³⁰ Exhibit 3539-X0194, CCA argument, PDF page 26 of 42.

²³¹ Exhibit 3539-X0194, CCA argument, PDF page 26 of 42.

²³² Exhibit 3539-X0194, CCA argument, PDF page 26 of 42.

breakout areas. So we were -- we're constantly in need of some more of that kind of space. So we will continue to assess our needs as we go forward.

... We have a facilities group in corporate, and they are in charge of managing the tower and the use of the space and the costs to maintain that space. So they would be the ones that would be keeping an eye on the costs and keeping them down.

Q. And watching the overlap, making sure everything is adjusted properly in terms of costing?

A. MS. ZROBEK: That's correct.²³³

339. With respect to the CCA's suggestion on rental costs, EDTI noted that the lease for the EPCOR Tower space was entered into in 2007, based on the EPCOR group's business plans and reasonably forecast space requirements at the time. The need for the space, and the resulting price, square footage, etc. was thoroughly scrutinized by the Commission and interveners at that time. The Commission approved the allocations and cost, subject to a significant disallowance in respect of the per square foot rental rate under the lease. Commitments for leased office space are long-term in nature, and changes in business space requirements and utilization are to be expected as businesses and the environment in which they operate change and evolve over time. Given that office space leasing commitments are long term in nature, EDTI submitted that it is unreasonable to conclude that utility shareholder should bear the cost of relatively small amounts of temporarily vacant space that may be temporarily underutilized, but that will become fully utilized within a short period of time. In addition, EDTI indicated that the record demonstrates the corporate services space rent costs allocated to EDTI transmission, as reflected in the application, are reasonable.²³⁴

Commission findings

340. The main issue for consideration with respect to the EPCOR Tower rental costs is the decrease in EDTI transmission's direct utilization of rental space compared to the increased corporate cost allocation of EPCOR rental costs. This is due to other business units vacating EPCOR Tower space in 2015, and EPCOR Water Services Inc. employees moving from EPCOR Tower to Rosssdale in 2015, and EDTI employees moving out during 2016 as part of the work centre redevelopment project.

341. The Commission is of the view that a decision by business units to transfer from the EPCOR Tower to Rosssdale or another location should not necessarily lead to an increase in allocated corporate rent costs, based on a decline in direct assigned costs and utilized space. This view is based, in part, by a lack of clarity in the evidence on the record as to whether the vacated space will be utilized by corporate or another business unit, be vacant during the test period, or leased. The Commission finds that EDTI has not justified why the costs associated with higher corporate rent costs that arise because of underutilized space should be included in revenue requirement. EDTI has failed to explain why these costs are required for the provision of utility service. Accordingly, EDTI transmission is directed to remove from its revenue requirement for the test period the cost increases to EDTI that are attributed to the vacant space and higher corporate rent allocations associated with the 2015 move of EPCOR Water Services Inc. employees from the EPCOR Tower to Rosssdale.

²³³ Transcript, Volume 4, pages 786-788.

²³⁴ Exhibit 3539-X0197, EDTI reply argument, PDF pages 45-46 of 80.

342. With respect to EDTI's move from the EPCOR Tower in 2016 as part of the work centre redevelopment project, EDTI provided, in response to EDTI-UCA-2015FEB06-019(f), information that is summarized in the table below regarding the impact of the direct rent and security savings:

Table 26. Impacts on EDTI costs resulting from move out of EPCOR Tower

Impacts from project		A 2015 F	B 2016 F	C 2017 F	D Reference
		(\$ million)			
1	Direct rent and security savings from vacating EPCOR Tower	-	0.26	0.28	Table 7.2-1, rows 15, 16
2	Increased corporate allocations	-	(0.18)	(0.16)	Table 7.3.1.1.10-1 row 10
3	Total savings	N/A	0.08	0.12	

Source: Table EDTI-UCA-2015FEB06-019-9.

343. These savings are offset partially by increased corporate services cost allocations related to EDTI's portion of increased corporate EPCOR Tower costs as a result of the move.

344. The Commission agrees with EDTI that Table 26 above demonstrates cost savings from vacating the EPCOR Tower. However, EDTI has failed to include in the above table and in its work centre redevelopment project business case, a complete assessment of costs that include the resulting higher corporate allocation of rental costs, the savings in direct rent, and the asset usage fee associated with using assets of EDTI distribution. More importantly, the Commission is not satisfied that the costs arising from a lower utilization of EPCOR Tower are required for the provision of utility service. Accordingly, EDTI is directed to remove the increased corporate allocation of EPCOR Tower costs associated with the work centre redevelopment project from its 2016 and 2017 revenue requirement.

345. For the remaining allocated costs, the Commission finds that the operating costs for 2015-2017 be held to the 2014 rate approved in Decision 2014-269, plus annual adjustment for inflation. The Commission considers that applying inflation to the approved 2014 operating costs is consistent with the range in operating costs (\$15.17-\$19.17 per square foot)²³⁵ that EDTI provided in the Collier's report (2014 Q4). The Commission directs EDTI to adjust its forecast operating costs to the rates approved in 2014 escalated by the inflation rate approved in Section 7.4.4.

346. Because the base rental rate remains at \$39.00 per square foot²³⁶ consistent with the rate approved in Decision 2014-269, no adjustment is required to the EPCOR Tower base rent rates.

8 Transmission work for others (Account 577)

347. EDTI provided historical and forecast costs related to transmission work for others in Section 5.0 of its application. Costs and revenues in this account relate to non-tariff services provided by EDTI transmission to other parties. EDTI noted that it develops the forecasts for this category based on the best information available. In some cases, EDTI stated that it uses relevant

²³⁵ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-026-1-Table.

²³⁶ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-026, Attachment 1, line 5.

historical information, such as typical service levels, or service level requirements as the basis for reliable forecasts of what will be required over the test period.²³⁷

348. In Direction 25 of Decision 2014-269, the Commission directed EDTI to calculate its 2013-2014 forecast revenue for transmission work for others based on a three-year historical average for 2010-2012 using actual revenue for transmission work for others. EDTI complied with the direction in its compliance filing to Decision 2014-269. In the current application, EDTI has not used this approach for its 2015-2017 forecast revenue in this category and it supplied the following reasons for not using a three-year average:

- Historical information is not a reliable source of information for forecasting the costs in all categories and, in particular, one-off projects for third parties.
- The three-year average approach can produce inaccurate and unreliable forecasts. EDTI's forecasts have been reasonably accurate, with both over and under forecasts over the six-year period. In contrast, the three-year historical average approach would almost always have over-forecast revenues and would have produced less accurate forecasts in most years.
- The three-year average approach is not a feasible or workable approach for forecasting revenue for services that are based on allocations.²³⁸

349. For these reasons, EDTI has not used historical averages as a basis for transmission work for others going forward, but used the best information available to it at the time the forecast was made.²³⁹

350. EDTI recalculated the 2015-2017 forecast expenses and revenues with respect to transmission work for others using both methods, the three-year normalized average methodology, as directed by the Commission in the last decision, and the best information available methodology, as EDTI has historically done. The results are shown below in Table 27. EDTI submitted that the two forecasts were not materially different.

Table 27. Transmission work for others 2015-2017 forecast

Methodology used	2015	2016	2017
	(\$ million)		
Best information available	(0.10)	(0.10)	(0.10)
Three-year average	(0.10)	(0.11)	(0.11)

Source: Exhibit 3539-X0193, EDTI argument, paragraph 227.

351. EDTI submitted that while the two forecasting approaches do not produce materially different results in the test period, for the reasons summarized above, EDTI should continue to utilize the best information available as reflected in its forecast for the test period.

²³⁷ Exhibit 3539-X0193, EDTI argument, paragraph 224, PDF page 96 of 259.

²³⁸ Exhibit 3539-X0193, EDTI argument, paragraph 225, PDF page 96 of 259 and described more fully in Exhibit 0003.00.EDTI-3539, EDTI application, Section 5, starting on PDF page 359 of 900.

²³⁹ Exhibit 3539-X0193, EDTI argument, paragraph 226, PDF page 96 of 259.

Commission findings

352. In Decision 2014-269, the Commission directed EDTI to use a three-year average to forecast its transmission work for others costs.²⁴⁰ In that decision, the Commission stated “[t]he Commission considers that use of a three-year average would take into account the fluctuation in revenue offsets identified by EDTI, and would also account for discrete projects that may arise in a given test year.”

353. The Commission continues to find that the use of a three-year average takes into account the fluctuation in revenue offsets identified by EDTI, and the Commission's findings in Decision 2014-269 are equally applicable to the 2015-2017 test period. The Commission still considers that transmission work for others is difficult to forecast and therefore the use of a three-year average is reasonable.

354. Accordingly, the Commission directs EDTI to incorporate the use of a three-year average using 2012-2014 actuals to determine its transmission work for others for inclusion in its 2015-2017 forecast revenue requirement, in the compliance filing to this decision.

9 Transmission deferral and reserve accounts

355. This section reviews two items: first, the revenue that EDTI is requesting to collect or refund in 2015 in regard to the true-up of transmission deferral and reserve accounts that were in effect in 2014 or earlier; second, the continuation of reserve and deferral accounts proposed for 2015-2017 and the associated funding or placeholder amount, if any, included in the revenue requirements for 2015-2017.

356. EDTI applied for the continuation through the test years of five deferral or reserve accounts which were approved in Decision 2014-269. The actual and forecast information on the transmission deferral and reserve accounts is provided in the following table:

Table 28. Summary of transmission deferral and reserve accounts 2011-2017

Description of deferral or reserve account	2013 Decision 2014-269	2013 actual	2014 Decision 2014-269	2014 actual	2015 forecast	2016 forecast	2017 forecast
		(\$ million)					
Hearing cost reserve	0.00	0.04	0.32	0.36	0.05	0.24	0.24
Self-insurance reserve (SIR)	(0.12)	-	(0.02)	(0.14)	-	-	-
Property, business & linear tax deferral account	-	-	-	0.55	(0.55)	-	-
AESO directed projects deferral account	0.39	(0.82)	-	(2.46)	3.58	-	-
Short-term incentive (STI) deferral	(0.06)	0.05	-	(0.06)	(0.05)	-	-
Total	0.24	(0.77)	0.30	(1.76)	3.03	0.24	0.24

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 11-7-1.

357. EDTI stated that it is unable to reasonably forecast the amount of hearing costs that it will incur in the test period and therefore, the transmission hearing cost reserve account for 2015, 2016, and 2017 is required. Similarly, EDTI recovers costs through the self-insurance reserve

²⁴⁰ Decision 2014-269, paragraphs 301-302.

account that meet the criteria set out in EDTI's procedure for claims against self-insurance reserve, and therefore cost recovery through the reserve account is required.

358. EDTI submitted that property, business and linear taxes are beyond its control and are consequently difficult to forecast accurately. EDTI stated that it has prepared its forecast consistent with the Commission's conclusions in Decision 2014-269 and in discussions with its property tax advisor on forecast mill rates and Alberta Municipal Affairs on AESO and other linear tax issues.

359. EDTI indicated with respect to the AESO directed projects deferral account, the AESO, under the *Electric Utilities Act* and the *Transmission Regulation*, AR 86/2007, has responsibility for transmission planning. EDTI added that it has little control over the expansion or enhancement projects that are AESO directed, and that the deferral account respecting these projects was still required. For 2013 and 2014, the actuals were provided.

360. For 2015, the AESO directed projects deferral account forecast included in revenue requirement was related primarily to a true-up for the Heartland project in the amount of \$2.59 million. The true-up of these costs was anticipated to occur in 2015 in conjunction with the AltaLink 2012-2013 DACDA process, Proceeding 3585, where the Heartland capital project costs would be examined.

361. In its update for 2014 actuals, EDTI did not forecast expenditures related to Heartland in the test years, but indicated during the hearing that there would be, and in fact had been, some trailing costs incurred in 2015 related to alternating current (AC) mitigation of pipelines in the Heartland area. EDTI also said it would be possible that trailing costs would be incurred in 2016.²⁴¹

362. When questioned during the hearing about the AltaLink DACDA process lagging significantly behind EDTI's GTA proceeding, and whether an adjustment to the timing of the Heartland deferral account true-up amount was necessary, EDTI responded that the timing of the two proceedings should not impact its 2015 revenue requirement. EDTI stated that since it had already outlaid a substantial amount of money to complete the Heartland project, the deferral account true-up forecast in 2015 is essentially a true-up of funds spent to the end of 2014.

363. EDTI considered it reasonable to forecast a deferral account true-up, recognizing that the ability to true-up at future points in time remains an option. Mr. Baraniecki stated at the hearing, "Until that project is completely closed out and the final dollars are expended and then accounted for on an actual basis and then subsequently approved, that deferral account is open, is how the AESO direct-assigned deferral account works."²⁴²

364. Lastly, EDTI noted that the deferral account for STI payments was directed by the Commission in Decision 2010-505, and captures any approved short term incentive amounts in revenue requirement that are not actually paid out. This deferral account allows for unpaid STI amounts to be returned to customers.

²⁴¹ Transcript, Volume 2, pages 405-406.

²⁴² Transcript, Volume 2, page 253.

Commission findings

365. The Commission accepts EDTI's reasons for continuing the five deferral accounts included in the application. With the exception of the AESO directed project deferral account, the Commission approves the amounts shown in Table 28, including the forecast amounts, subject to any true-ups or adjustments arising from directions elsewhere in this decision.

366. The Commission approves the continuation of EDTI's AESO directed project deferral account. However, because the examination of the Heartland project costs is in conjunction with the AltaLink DACDA proceeding, the Commission considers the 2015 forecast true-up for the Heartland project to be premature. Because the Commission considers it more likely that Proceeding 3585 will be finalized during 2016 than 2015, recognizing the corresponding forecast for EDTI's true-up for the Heartland project in 2016 is more reasonable.

367. Accordingly, EDTI is directed to remove the deferral account true-up respecting the Heartland project from its 2015 forecast and to reflect this amount in its forecast for 2016, in its compliance filing to this decision.

10 Rate base

10.1 2015 opening rate base

368. EDTI has requested approval of its opening 2015 net transmission rate base of \$624.3 million.²⁴³

369. The following table shows a comparison of approved to actual closing mid-year rate base amounts for the period from 2012 to 2014. The variances between the forecast and actual amounts range from 0.10 per cent to 5.5 per cent over forecast:

Table 29. Transmission mid-year rate base (less working capital) – actual versus decision 2012-2014

	2012	2013	2014
	(\$ million)		
Decision	332.0	461.1	589.4
Actual	332.4	471.3	621.8
\$ over (under) decision to actual	0.4	10.2	32.4
% over (under)	0.1%	2.2%	5.5%

Source: Decision 2012-272, Table 29 and Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 9-1, line 3 less Schedule 10-1, line 10.

370. In order to assess the reasonableness of the 2015 opening rate base, the Commission has examined the actual capital expenditures and additions for the years 2013 and 2014. In this section, the Commission will consider changes in construction work in progress (CWIP) due to the timing of the completion of projects, and any significant variances between costs incurred and forecast costs.

²⁴³ Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 9-1, line 3.

371. As shown in Table 30 below, 2013 actual capital expenditures were \$2.5 million lower (\$30.8 million less \$28.3 million) than the amount approved in Decision 2014-269, while capital additions to rate base were \$0.3 million lower (\$28.0 million less \$27.7 million) than the approved amount. Actual approved closing 2013 CWIP was \$2.2 million lower (\$15.2 million less \$13.0 million) than the decision amount.

372. For the year 2014, Table 30 shows that 2014 actual capital expenditures were \$0.9 million higher (\$41.7 million less \$42.6 million) than the amount approved in Decision 2014-269, while capital additions to rate base were \$4.1 million lower (\$44.3 million less \$40.2 million) than the approved amount. Actual approved closing 2014 CWIP was \$3.2 million higher (\$12.6 million less \$15.4 million) than the decision amount.

Table 30. Transmission capital expenditures and capital additions (excluding Heartland and contributions) 2012-2014

	2012 decision	2012 actual	2013 decision	2013 actual	2014 decision	2014 actual
	(\$ million)					
Opening CWIP	24.3	24.3	12.4	12.4	15.2	13.0
Cap Ex	63.5	39.9	30.8	28.3	41.7	42.6
Subtotal	87.8	64.2	43.2	40.7	56.9	55.6
Closing CWIP	34.4	12.4	15.2	13.0	12.6	15.4
Cap adds to RB	53.4	51.8	28.0	27.7	44.3	40.2
Over (under) actual to decision		(1.6)		(0.3)		(4.1)

Source: Exhibit 3539-X0086, CWIP continuity schedule updated for 2014 actuals.

373. The Commission examined the amount each of EDTI's 2013 and 2014 projects has contributed to the 2013 and 2014 capital variances and EDTI's proposed capital additions to rate base, in detail. The Commission has prepared a summary of EDTI's explanations for the variances in 2013 and 2014. This summary can be found in [Appendix 4](#) to this decision. In certain cases, the Commission questioned variances that resulted in greater actual costs than those originally forecast.

374. With respect to EDTI's transmission vehicle life cycle replacement and growth project (reference 9.2.7), the Commission explored a \$0.23 million increase from 2013 decision to 2013 actuals. The Commission noted that the majority of the 2013 variance was attributed to the cost of purchasing a flat deck truck with crane,²⁴⁴ which had an approved forecast cost of \$0.21 million but for which EDTI reported an actual cost of \$0.41 million.²⁴⁵ EDTI explained that the forecast cost for this vehicle had been based on the actual cost of a similar vehicle purchased in 2003. EDTI advised that it utilized a request for proposal (RFP) process to purchase this vehicle, but that only one compliant bid was received.²⁴⁶ EDTI clarified in subsequent questioning by the Commission panel that these types of specialized vehicles cannot be purchased through the agreement EDTI has with the City of Edmonton that allows for the purchase of different types of fleet vehicles at better rates.²⁴⁷

²⁴⁴ Unit number T3023.

²⁴⁵ Exhibit 0034.00.EDTI-3539, Appendix E-2-T-PIR-06.

²⁴⁶ Ibid. See also Transcript, Volume 4, pages 648-649.

²⁴⁷ Transcript, Volume 5, pages 950-951.

375. The Commission also considered a \$2.95 million increase in capital additions from the 2014 approved forecast to 2014 actual result, with respect to its life cycle replacement of 240-kV cable sections project (reference 9.2.3.2). EDTI explained in a variance analysis that \$2.51 million of this variance was attributed to higher contractor costs for the replacement of the 240BA3 transmission cable section and cable terminations.²⁴⁸ EDTI noted that it received a single bid from a qualified contractor in response to its RFP. EDTI also described additional steps it took to assess the bid, which was substantially higher than the forecast amount, before awarding the contract to the single bidder.²⁴⁹ EDTI confirmed during questioning by Commission counsel that it did not believe there were any other options (such as delaying the project or bidding the work in conjunction with a larger project) to mitigate this increase in costs in this case.²⁵⁰

376. No intervenor raised concerns with EDTI's 2015 opening transmission capital rate base amounts.

Capitalization of short-term incentive costs

377. In its application, EDTI stated that during 2014 it included an allocation of short-term incentive (STI) program costs to its capital overhead pool based on either time spent or headcount, and stated that the inclusion of these costs is consistent with AUC [Rule 026: Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards](#) and EPCOR's Capital Overhead Policy. EDTI noted that historically the incentive pay costs had not been capitalized but instead, were included within the MOP operating cost category.

378. During the hearing, EDTI stated that the main impetus to include a portion of STI costs in its capital overhead costs was based on an examination of its existing capitalization policy and identifying within that policy, that costs directly attributable to the execution or delivery of a capital project would be eligible for capitalization.²⁵¹

379. Specifically, EDTI's capitalization policy states that costs should include:

... the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment. This incorporates all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use....²⁵²

380. EDTI stated that the incentive pay is directly attributable to the "execution or delivery of a capital project"²⁵³ and is consistent with its capitalization policy, and should therefore be capitalized. EDTI stated that in 2015 it would capitalize \$1.34 million in incentive pay that would have otherwise been recorded as MOP operating costs using the same approach that it used to calculate the capitalized portion of non-wrench costs.²⁵⁴ EDTI indicated that the impact of

²⁴⁸ Exhibit 3539-X0084, page 9.

²⁴⁹ Ibid. See also Transcript, Volume 3, pages 615-616.

²⁵⁰ Transcript, Volume 3, page 615.

²⁵¹ Transcript, Volume 4, page 758.

²⁵² Exhibit 0015.00.EDTI-3539, Appendix C-1, Capitalization for Regulatory Accounting Purposes, page 3.

²⁵³ Transcript, Volume 4, page 758.

²⁵⁴ Exhibit 0003.00.EDTI-3539, application, paragraph 274, PDF page 118 of 900.

this change on revenue requirement is a decrease of \$0.35 million, \$0.33 million and \$0.31 million in the years 2015, 2016 and 2017, respectively.²⁵⁵

381. In its update providing for 2014 actuals, EDTI's variance explanations show a \$0.36 million increase between 2014 decision amounts and 2014 actual amounts. This increase is reflected in the credit related to administrative expenses transferred, which includes "a portion of employee incentive costs in EDTI's capital overhead pool."²⁵⁶ The effect of this adjustment was to increase the reduction to EDTI's administration and general costs, thereby reducing actual operating costs for 2014 by \$0.36 million.

382. During the hearing, EDTI witnesses confirmed that capitalized STI costs were included in the 2014 updated forecasts²⁵⁷ but the 2014 revenue requirement, based on Decision 2014-269, did not reflect the inclusion of the incentive pay in the capital overhead pool. The first time that the change in capitalization is reflected in revenue requirement is in 2015. EDTI clarified that while its proposal was intended to forecast the capitalized incentive pay at target STI, when actual results are finalized for a given year, the capitalized incentive portion would reflect STI on an actual basis.²⁵⁸

383. The CCA was concerned that the metric used to assess STI costs is the "variance actual to base approved capital"²⁵⁹ and was designed to only incent behaviour encouraging completion of projects while ignoring other desirable outcomes, such as achieving economic efficiency in design, planning, capital budgeting and project execution.

384. With respect to capitalization of STI costs in 2014, the CCA stated that the capitalization of STI was not contemplated in Decision 2014-269. The CCA concluded that based on EDTI's update for 2014 actuals, the cost variance explanation provided shows the variance was due to capitalization of a portion of the STI costs, which had not been forecast or approved at the time of EDTI's last GTA. The CCA took issue with the change in EDTI's application of its capitalization policy from STI costs being an operating expense, when the 2014 revenue requirement was established, to subsequently being capitalized into rate base in 2014 on an actual basis and recovered from customers over the life of the corresponding assets. In the CCA's view, this will result in customers having to pay the same cost twice and amounts to a violation of the regulatory compact.²⁶⁰ The CCA recommended that the 2014 actual capital costs be reduced by \$0.29 million in indirect support to capital, for the purposes of the compliance filing.

385. EDTI responded that capitalization of the STI costs in 2014 reflects its current capitalization policy, is the correct approach from an accounting perspective and is not a violation of the regulatory compact. It is simply the application of EPCOR's existing capitalization policy to STI costs. Further, the capitalization of STI costs result in benefits to customers on a go-forward basis, as evidenced by the reductions in revenue requirement for 2015 through 2017.²⁶¹

²⁵⁵ Exhibit 3539-X0005, IR response to EDTI-AUC-2015FEB06-11.

²⁵⁶ Exhibit 3539-X0084, Attachment 4, line 25, PDF page 6 of 8.

²⁵⁷ Transcript, Volume 4, page 759.

²⁵⁸ Transcript, Volume 4, page 759.

²⁵⁹ Exhibit 3539-X0194, CCA argument, paragraph 54, PDF page 20 of 42.

²⁶⁰ Exhibit 3539-X0194, CCA argument, paragraph 22, PDF page 9 of 42.

²⁶¹ Exhibit 3539-X0197, EDTI reply argument, paragraphs 39-41, PDF page 18 of 80.

Heartland project (reference 9.2.1.7)

386. The Heartland project, a shared project with AltaLink, was added to EDTI's rate base in the amount of \$240.57 million in 2013. Further costs were incurred during 2014 in the amount of \$28.03 million, thus bringing total actual costs to \$268.60 million. This amount was considered to be a placeholder amount subject to AESO directed projects deferral account treatment.

387. EDTI's share of actual capital cost in the amount of \$268.60 million was confirmed during the hearing as consistent with information provided in the AltaLink direct assigned capital deferral account (DACDA) filing in Proceeding 3585 as at December 31, 2014.²⁶²

388. In its application, EDTI anticipated that AltaLink would shortly file its 2012 and 2013 DACDA reconciliation application and proposed that the Heartland project capital additions approved by the Commission in AltaLink's DACDA reconciliation proceeding be incorporated into the approved opening rate base in EDTI's 2015-2017 GTA at the time of its compliance filing. EDTI stated that any adjustments to the Heartland placeholder amount filed in its GTA would be trued up to reflect the Commission's decision in the AltaLink DACDA proceeding.

389. In response to an IR,²⁶³ EDTI confirmed:

... a contribution amount will be made by one party to the other so that each party will have the same rate base values for their respective project facilities. The party that makes the contribution would add the contribution amount to rate base and recover return, while the other party would treat the contribution as no-cost capital, which would have the opposite effect. The contribution would decrease the rate base value of the project facilities of the party receiving the contribution and therefore would offset the return that would have been recovered.²⁶⁴

390. When asked to provide a reference to Proceeding 3585, where the contribution amounts between AltaLink and EDTI had been calculated, EDTI responded that the AltaLink proceeding had not included an identified contribution amount from one party to the other, but anticipated that a reconciliation of the capital costs and contributions would be forthcoming.

391. During the hearing, EDTI responded to questions by Commission counsel on how the Heartland contributions would be implemented between EDTI and AltaLink so as to result in a 50/50 split of the total project costs.²⁶⁵

Commission findings

392. The Commission has reviewed the analyses of individual project variances, including the post implementation reviews (PIRs) included in the application. The Commission has also reviewed the variance explanations for the capital expenditures, capital additions and the opening and closing CWIP variances as provided by EDTI in its application, responses to IRs, information updates for 2014 actuals and testimony.

²⁶² Exhibit 3539-X0117, AUC aid to questioning "D."

²⁶³ Exhibit 3539-X0005, AUC information request, EDTI-AUC-2015FEB06-031(f).

²⁶⁴ Decision 2014-160, AltaLink Management Ltd. and EPCOR Distribution & Transmission Inc., Partitioning of Heartland Transmission Lines, Proceeding 2932, Application 1610091-1, June 6, 2014, paragraph 31 referencing the equal sharing principle as described in the partition agreement.

²⁶⁵ Transcript, Volume 2, pages 409-411.

393. With respect to the purchasing of a flat deck truck with crane, based on the information on the record of the proceeding, the Commission approves the costs associated with the purchase of this vehicle for inclusion in rate base, notwithstanding the substantial cost variance.

394. With respect to the life cycle replacement of 240-kV cable sections project, based on the record of the proceeding, the Commission approves the costs, notwithstanding the substantial cost variance. The Commission has considered the additional steps EDTI undertook after receiving the initial response to its RFP and is satisfied that reasonable efforts were undertaken to control costs.

395. With respect to EDTI's rationale for its proposal to capitalize employee incentive pay where directly attributable to work conducted by employees on capital projects, the Commission agrees that the capitalization of incentive pay is consistent with the practices of other utilities operating within the province.

396. EDTI's forecast revenue requirement is based on an assumption of meeting STI targets. Once the actual results for a given year are finalized, it is the actual STI costs that will be capitalized, subject to a prudence review by the Commission at the time of EDTI's next GTA.²⁶⁶

397. Based on the information provided in EDTI's updated forecasts for 2014 actuals and its oral testimony, it appears EDTI has reflected the capitalization of STI costs on an actual basis in 2014, with the effect of reducing operating costs by \$0.36 million.

398. The Commission agrees with the CCA that the reduction to operating expense had not been contemplated in the 2014 approved forecast revenue requirement in Decision 2014-269, where the recovery of STI costs for 2014 was determined. The Commission considers that EDTI's recovery of the capitalized amounts for STI in 2014 results in those same STI costs being recovered twice: once in the 2014 approved forecast revenue requirement as an operating cost, and again as a component of 2015 opening rate base, given the capitalization of amounts in 2014.

399. For these reasons, the Commission directs EDTI to reduce its 2015 opening rate base by the amounts reflecting the capitalization of STI costs in 2014. In its compliance filing to this decision, EDTI is to reflect this direction in its actual closing 2014 CWIP balances on a project by project basis, in order to ensure that the 2015 forecast and actual opening rate base will not include any capitalized 2014 STI amounts.

400. Accordingly, EDTI is directed in its compliance filing, to include a list identifying the projects affected by this direction and the corresponding dollar impacts in 2014. The Commission also directs EDTI to include an updated version of its CWIP continuity schedule reflecting the Commission's direction regarding the capitalization of STI costs in 2014, and an explanation of any corresponding impacts of this direction and any other direction in this decision that affects its CWIP continuity schedule.

401. For the purposes of this decision, the Commission makes no finding with respect to the prudence of EDTI's capital additions for the Heartland project that form a component of EDTI's 2015 opening rate base. Given that the Heartland project capital additions approved by the Commission in AltaLink's DACDA reconciliation proceeding will not be available prior to the filing of EDTI's compliance filing to this decision, these amounts are to be reflected in EDTI's

²⁶⁶ Exhibit 3539-X0193, EDTI argument, paragraphs 165-166, PDF page 70 of 259.

next GTA, following the finalization of the Heartland project costs in the AltaLink DACDA and any subsequent refiling(s) or compliance filing(s) associated with that proceeding.

402. However, from the information on the record of this proceeding, it is not apparent whether, and in what amount, any contributions between EDTI and AltaLink are reflected in EDTI's 2015-2017 GTA. Therefore, the Commission directs EDTI in its compliance filing to this decision, to identify the contribution amount, if any, that has been included in the \$268.60 million capital additions recorded by EDTI.

403. With the exception of the AESO directed projects, for which the variances will be considered in the true-up of EDTI's AESO directed projects deferral account, the Commission accepts the remaining variance explanations provided by EDTI related to its 2013 and 2014 capital expenditures, capital additions, and opening and closing CWIP balances.

404. Additionally, based on the foregoing, the Commission approves EDTI's capitalization of STI costs reflected in its forecast revenue requirement for the 2015-2017 test period, commencing in the year 2015.

405. Subject to the directions with respect to capitalized STI and Heartland project contributions identified in these findings, the Commission approves EDTI's 2015 opening rate base, for the purpose of determining revenue requirement for the test period.

406. The Commission discusses two additional matters related to EDTI's 2015 opening rate base in the sections which follow.

10.1.1 Variance analyses and post-implementation reviews

407. In Decision 2014-269, the Commission stated the following:

48. Direction 28 at page 70 of Decision [2006-054](#)²⁶⁷ provided that the threshold for further investigation of capital projects should be a minimum approved forecast cost of \$500,000 and a variance from the approved forecast of greater than 10 per cent. The Commission ... directs EDTI to refer to this direction in its future GTAs.²⁶⁸

408. The Commission also provided guidance with respect to the variance analyses and PIRs provided by EDTI:

83. With respect to applied-for additions to opening rate base, the Commission found it difficult to assess the extent to which variances between forecast and actual costs were due to changes in the physical work undertaken, substitution of project components, changes in scope, or cost over-runs and under-runs.

²⁶⁷ Decision 2006-054: EPCOR Transmission Inc., 2005/2006 Transmission Facility Owner Tariff, Application 1389884; EPCOR Distribution Inc., 2005/2006 Distribution Tariff – Phase I, Application 1389885, June 15, 2006.

²⁶⁸ Direction 28 of Decision 2006-054 provided “The position advanced by EDI/ETI would place the Board in an untenable position. The Board has determined that a two-part minimum test should apply for EDI capital projects and ETI capital maintenance projects. Specifically, the Board considers that the appropriate trigger for further investigation of EDI capital projects and ETI capital projects should be a minimum approved project forecast cost of \$500,000 and a variance from the approved forecast of greater than 10%. Accordingly, to the extent that the final costs of any EDI capital projects and ETI capital maintenance projects approved in this Decision fall outside of the variance thresholds just described, the Board also directs EDI/ETI, in the next GTA, to include such variance reporting.” [footnotes omitted]

84. The following description of what should be addressed in post-implementation reviews (PIRs) is provided in the MFRs:

Typically, PIRs should involve a comparison of approved business cases to actual experience and a comparison of actual costs and benefits of the project with costs and benefits approved in the business case. A PIR should also include a comparison of the completed project with the planned project. This includes such items as the size, capacity, throughput functionality, or other characteristics that may be different than planned. Any differences should be fully explained. Finally, PIRs should address any process improvements implemented for future projects as a result of reviewing the project.

85. EDTI provided PIRs for larger projects and for smaller projects some explanation was provided in the application. However, the presentation did not always comply with the MFRs or allow the Commission to understand the overall reason for the identified variances.

409. In its 2015-2017 GTA, EDTI stated that it prepared PIRs for capital projects “for which the variance between forecast and actual capital additions is greater than \$500,00, or is greater than 10% and \$125,000.”²⁶⁹ EDTI advised that in response to the Commission’s comments in Decision 2014-269, it had revised the content of its PIRs in three ways:

- EDTI included PIRs only with respect to completed projects, or for programs that involved multiple projects, PIRs were provided when the completed projects in the program, in total, had a variance from forecast that met the PIR threshold.
- EDTI more clearly indicated the overall reason for the variance.
- EDTI more clearly addressed what the MFRs indicated should be included in a PIR, including a comparison of forecast and actual business case/cost-benefit analysis, a comparison of the completed project to the planned project, and any process improvements occurring as a result of reviewing the project.²⁷⁰

410. EDTI also indicated that, with respect to both the operating cost and capital additions, it provided, among other things, explanations of variances from 2013 decision forecast amounts to 2013 actual amounts and 2014 decision forecast amounts to 2014 updated forecast amounts.²⁷¹

411. EDTI provided PIRs for six²⁷² capital projects that were completed in 2013 in its application. Of the six PIRs provided, four related to non-AESO directed projects. EDTI also provided explanations of other capital variances as discussed above. However, these variance analyses did not uniformly provide the same level of information or analysis found in the PIRs or that is required of PIRs pursuant to the Commission’s MFRs.

²⁶⁹ Exhibit 0003.00.EDTI-3539, application, at paragraph 242.

²⁷⁰ Exhibit 0003.00.EDTI-3539, application, paragraph 244, PDF page 106 of 900.

²⁷¹ Exhibit 0003.00.EDTI-3539, application, paragraph 247, PDF page 107 of 900.

²⁷² EDTI stated in its application that it provided seven PIRs but T-PIR-01 as provided in Exhibit 0034.00.EDTI-3539, Appendix E-2, was a blank document. Additionally, at paragraph 2215 of the application, EDTI references T-PIR-08 discussing EDTI’s 2013 forecast and actual expenditures and rate base additions for completed components of the medium voltage switchgear replacement program, however, no T-PIR-08 was provided in Appendix E-2, nor was it referred to in Table 9.2-1 of the application.

412. As EDTI's application was filed in November 2014, it did not have 2014 actuals and was not able to file PIRs for 2014 capital projects at the time of filing its application. On April 21, 2015, the Commission issued correspondence directing EDTI to file its 2014 actual information, including: "[a]ll available post implementation reviews (PIRs) for projects completed in 2014 and for projects for which PIRs are not required explanations of significant cost variances from previously provided forecasts (e.g., with respect to the volume of work completed and variances in specific cost classifications."²⁷³ The Commission ordered that EDTI should include the following in its variance analyses:

- (a) In circumstances where EDTI states that certain work performed or costs incurred were "not contemplated," provide a detailed explanation as to why the work or the costs were not contemplated.
- (b) Identify any changes in plans, policies or priorities that may have contributed to or caused the variance(s).

413. On May 22, 2015, EDTI filed its 2014 actual information and advised that:

No post implementation reviews (PIRs) for projects completed in 2014 are available at this time. EDTI will be able to provide the PIRs as part of EDTI's next Tariff Application. For all projects where the variance is greater than the threshold outlined in part (j) above, regardless of whether it would be a PIR project or not, EDTI provides explanations of significant variances in Attachment 4.

414. Attachment 4²⁷⁴ provided certain explanations associated with variances between 2014 decision and 2014 actual information. However, as with the variance explanations provided in the application, these variance analyses did not uniformly provide the same level of information or analysis found in the PIRs or that is required of PIRs pursuant to the Commission's MFRs.

415. Notwithstanding the information provided by EDTI in its application, the Commission provides the following comments with respect to the variance analyses provided by EDTI.

416. EDTI frequently explained variances of less \$50,000 and less than 10 per cent of the total forecast capital additions. For greater clarity, the Commission reiterates its requirement that EDTI must provide a capital variance analysis only where the two following conditions are satisfied. First, the total forecast cost of the project must be \$500,000 or greater and second, the total variance from forecast to actual costs of the project must be greater than 10 per cent of the full forecast amount of the project. For example, if a project with a forecast cost of \$500,000 exhibits a variance between forecast and actual costs greater than \$50,000, EDTI would be required to provide a capital variance analysis. Nonetheless, EDTI may choose to provide more information than is required by this decision.

417. In its application, EDTI chose to provide more information than is required. To the extent that EDTI provides additional information, the Commission would find the following helpful.

418. The Commission finds it would be useful to be able to discern and understand significant variances for individual subcategories of a project or program when a capital project or program encompasses two or more subcategories. This is important because EDTI may have experienced

²⁷³ Exhibit 3539-X0067, AUC letter, additional information – 2014 actual results.

²⁷⁴ Exhibit 3539-X0084, Attachment 4, 2014 transmission capital variance explanations (actual).

a significant cost overrun on one subcategory of a project or program, that is offset by a significant underrun on another subcategory of the project or program, so that the total combined variance is insignificant.

419. The Commission also finds it helpful to be able to identify the exact source of a specific variance. Some variances are attributed to work being completed in years other than the year in which it was originally forecast (because work is either completed early or delayed). This can make it challenging for the Commission to compare the forecast costs associated with work that would have been completed in one period, with the actual costs of that work when it is completed in another period. This is because the forecast costs for the work in the period in which it is actually completed are no longer easily discernable. For example, this issue was present in the variance analysis for protective relay & control system life cycle replacements and improvements project for 2014.²⁷⁵ However, in the same exhibit with respect to the communication system life cycle replacement and system improvement project, the Commission found the explanation of the variance related to the Garneau substation to be helpful.

420. Additionally, where there is a change in the scope of a planned project arising from changes in the size, capacity, throughput functionality, or other characteristics of the project, it is preferable to be able to compare the actual costs of the project to the forecast costs of the project, taking into account the changes in scope. This is because the original forecast costs for the components of a project prior to the change in scope, or following the change in scope, to which the actual costs are being compared may or may not be provided. The Commission's understanding is better served when changes in scope are accounted for in a variance analysis, as was the case in Section 5.0 of E-2-T-PIR-03.²⁷⁶

421. Finally, the Commission recognizes that, in some instances, EDTI has traditionally provided a PIR, as a form of variance analysis. Generally, EDTI has adopted the following threshold for the provision of a PIR. A PIR is generally developed when the total variance between forecast and actual capital additions is greater than \$500,000 or when the total variance amount is greater than \$125,000, only if that variance is greater than 10 per cent of the total project forecast cost.

422. The Commission considers that PIRs are generally more informative than other forms of variance analyses. Accordingly, where EDTI identifies in its application that a PIR is required for a specific project, according to its established criteria, EDTI should ensure that the PIR is provided on the record of the proceeding.

423. The Commission acknowledges the changes implemented by EDTI with respect to its PIRs in response to the Commission guidance in Decision 2014-269. The Commission finds

²⁷⁵ Exhibit 3539-X0084, EDTI attributed a \$0.38 million decrease to having completed the Woodcroft substation 72-kV breaker failure protection life cycle replacement project in 2015 rather than 2014 as originally forecast. However, EDTI did not update the 2015 forecast to account for this work being delayed into 2015 and did not fully explain why the delayed work would not impact the 2015 forecast. EDTI also identified a \$0.13 million decrease in relation to the Genesee 500-kV bus differential project being advanced in 2013 rather than completed in 2014, and a \$0.10 million decrease related to the delay of the Namao substation regulator remote control and indication project from 2014 to 2015. Similar to the Woodcroft substation 72-kV breaker failure protection project, EDTI did not adjust its 2015 forecast to account for the work at Namao being delayed into 2015. PDF page 1 of 12.

²⁷⁶ Exhibit 0034.33.EDTI-3539, Appendix E-1: In E-2-T-PIR-03, paragraphs 10-11, EDTI provided information in respect of the change of scope and cost impact for the circuit breaker replacement project, PDF page 12 of 29.

generally that the information provided in PIRs has improved. The Commission considers that EDTI should provide all relevant elements set out in the Commission's MFRs for PIRs, in every PIR provided to the Commission.

424. When a variance analysis is provided, it is helpful if information similar to that provided in a PIR is provided to the extent such information is available and can be practically provided.

10.1.2 Implications of Direction 15 from Decision 2014-269

425. During the hearing, Commission counsel explored EDTI's compliance with and implementation of Direction 15 from Decision 2014-269, which stated:

15. To that end, the Commission directs EDTI to reflect the reductions in transmission operating FTEs of 4.4 in 2013 and 4.7 in 2014 and capital FTEs of 6.9 in 2013 and 5.1 in 2014, along with the corresponding reductions in FTE related costs and forecast capital expenditures, in its compliance filing. In implementing this direction, EDTI is directed to use an average cost per FTE of \$110,000 which results in FTE related operating expense and capital expenditure reductions of \$484,000 and \$759,000 respectively for 2013, and \$517,000 and \$561,000 for 2014 respectively. EDTI is further directed not to substitute contractor resources or increased overtime for the FTE reductions made for the test years. EDTI is directed to provide a schedule identifying where the resulting FTE adjustments have been made in the compliance filing. Paragraph 128

426. EDTI submitted that it had selected the nine projects in each year with the highest regular-time labour forecasts. The reductions were applied in proportion to each project's labour forecast.^{277 278}

427. EDTI confirmed that it had, for the purposes of its 2013-2014 forecast revenue requirement, made the directed reductions to its operating expenses and forecast capital expenditures in its compliance filing to Decision 2014-269. EDTI stated with respect to the adjustment to capital expenditures that, in the absence of the Commission directing reductions to specific capital projects, it had apportioned the reductions in the amount of \$759,000 for 2013 and \$561,000 for 2014 to the nine capital projects in each of those years with the highest regular-time labour forecast.²⁷⁹

428. When questioned why these same reductions to the affected projects did not appear to have been made on the basis of the actual dollars of capital spent, EDTI responded that it was not "paid for those costs" for ratemaking purposes, but agreed with Commission counsel that the same project costs would now be capitalized on an actual basis because they had been incurred in order to complete the projects.²⁸⁰

429. EDTI stated that it was not possible to reflect a reduction to revenue requirement of this type in its actual results.²⁸¹ Furthermore, EDTI submitted that, considering Decision 2014-269 was issued on September 18, 2014, and the subsequent related compliance filing to that decision

²⁷⁷ Exhibit 0003.00.EDTI-3539, application, paragraph 1855, PDF page 654 of 900.

²⁷⁸ Exhibit 0003.00.EDTI-3539, application, paragraph 1855 and Table 9.2-3, PDF pages 654-655 of 900. Paragraph 1855 states 10 projects were affected whereas Table 9.2-3 identifies nine projects.

²⁷⁹ Transcript, Volume 2, page 308, EDTI confirmed that Direction 15 reductions applied to nine projects.

²⁸⁰ Transcript, Volume 2, page 312.

²⁸¹ Transcript, Volume 2, pages 316-317.

approved on February 12, 2015 in Decision 3474-D01-2015, virtually all expenditures necessary to complete the nine identified projects had been incurred by that point in time.

Commission findings

430. The Commission reviewed the capital FTE reductions in EDTI's compliance filing to its 2013-2014 GTA and was satisfied in Decision 3474-D01-2015 that EDTI had reasonably addressed the Commission's Direction 15.

431. In reviewing the information related to Direction 15 on the record of this proceeding, the Commission noted that the implementation was not consistent with the description of the methodology EDTI provided.²⁸² Specifically, EDTI applied the cost reduction to four projects in 2013 and seven projects in 2014, rather than 10 projects in each year,²⁸³ and the amounts were not allocated in proportion to the regular-time labour forecast.²⁸⁴

432. EDTI cited Direction 15 as one of the reasons for variances in the actual costs of certain projects, as compared to what was approved in Decision 2014-269.²⁸⁵ With respect to the 2014 protective relay & control system life cycle replacements and improvements projects (reference 9.2.2.1), EDTI explained the variance in part, as follows: "\$0.09 million due to efficiencies in projects being completed at the same time, offset by the \$0.11 million impact of Direction 15."²⁸⁶

433. Although the Commission was unable to verify the impact of Direction 15 on other cited projects as clearly as for the 2014 protective relay & control system life cycle replacements and improvements project, the Commission analyzed the differences in capital additions and ending CWIP for the projects to which reductions were allocated and is satisfied that the labour amounts reflected in opening rate base are reasonable.

10.2 Overview of 2015-2017 forecast capital expenditures and additions

434. EDTI applied for approval of \$43.7 million of forecast transmission capital additions in 2015, \$65.2 million in 2016 and \$56.0 million in 2017. Forecast capital expenditures were in the amounts of \$48.6 million in 2015, \$70.0 million in 2016 and \$47.8 million in 2017.²⁸⁷

435. EDTI's forecast transmission capital additions were described in Section 9.2 of its application and EDTI's capital business cases.²⁸⁸ Further information was provided by EDTI in

²⁸² Exhibit 0003.00.EDTI-3539, application, paragraph 1855, PDF page 654.

²⁸³ Exhibit 0003.00.EDTI-3539, application, Table 9.2-2 and Table 9.2-3, PDF pages 654 and 655.

²⁸⁴ Exhibit 3539-X0177, undertaking by Mr. Baraniecki to Ms. Kellgren and Commission member Holgate, Table 1 for 2013 and Table 2 for 2014 present the 2014 labour as filed in column A and the impact of Direction 15 in column B. The percentage of the direction impact in column B to the 2014 as filed labour figures provided ranges from approximately eight per cent to 67 per cent. The Commission was unable to reconcile the labour costs to the business cases filed in Proceeding 2758.

²⁸⁵ For example, EDTI stated the following in relation to Transmission substation protection relay and control system life cycle replacements: "[a] \$0.16 million increase in capital additions for 2013 Decision to 2013 Actual is primarily due to: ... [a] \$0.14 million increase due to Direction 15 in Decision 2014-269 ... EDTI reduced its forecast capital additions related to this project by \$0.14 million as a result of this direction...." However, in Table 9.2.2.1-3 of its application EDTI provided a comparison of the decision and actual amounts for the this project. The capital expenditures were \$3.24 million compared to \$3.25 million approved, while the closing CWIP was \$1.15 million compared to the forecast of \$1.33 million. The variance in capital additions of \$0.16 million appears to be due to a lower than forecast closing CWIP balance.

²⁸⁶ Exhibit 3539-X0177 pages 3-4.

²⁸⁷ Exhibit 3539-X0086, CWIP continuity schedule updated for 2014 actuals.

information request responses²⁸⁹ and during the oral hearing. Details of EDTI's capital expenditures and additions by project, including historical actuals, approved amounts and forecast amounts were provided in Exhibit 3539-X0086, the updated CWIP continuity schedule for 2011-2017. This exhibit was updated to include 2014 actuals and any subsequent impacts to the 2015-2017 test period forecasts. EDTI advised that there were no anticipated impacts to the 2016 or 2017 forecast capital additions as a result of the 2014 actual capital additions.²⁹⁰

436. In its application, EDTI categorized its transmission capital additions, including AESO directed projects, as transmission substation equipment, underground transmission equipment, aerial transmission lines and general plant projects. Within each category, all similar projects were grouped into subcategories consistent with directions 31, 32, and 33 from Decision 2006-054. Consistent with these directions, EDTI further categorized individual capital projects as growth driven, process improvement, or life cycle replacement. EDTI's AESO directed projects are included within the growth category.

437. The following table of EDTI's transmission capital additions indicates that life cycle projects are the largest component of EDTI's 2015-2017 transmission capital program:

Table 31. Transmission capital additions summary 2012-2014

	2012 actual	2013 Decision 2014-269	2013 actual	2014 Decision 2014-269	2014 actual	2015 forecast	2016 forecast	2017 forecast
	(\$ million)							
Life cycle (LC) projects	14.58	22.62	21.68	26.41	27.26	29.40	19.82	52.28
Performance improvement (PI) projects	7.15	4.60	4.63	4.56	0.17	5.76	0.44	0.18
Growth projects (primarily AESO directed) *includes Heartland (direct assigned (DA))	30.07	223.16*	241.96*	13.29	40.82*	9.05	45.12	32.58
Subtotals	51.80	250.38	268.27	44.26	68.25	44.21	65.38	85.04
Contributions	(14.17)	-	2.17	(0.82)	(0.07)	(0.53)	(0.15)	(29.07)
Total	37.63	250.38	270.44	43.44	68.18	43.68	65.23	55.97

Source: Exhibit 3539-X0086, CWIP continuity schedule updated for 2014 actuals.

438. The transformer capacity upgrade project, also referred to as Lambton (reference 9.2.1.5) is an AESO directed project that accounts for approximately \$6 million or 15 per cent of the forecast capital additions in 2015.

439. The following seven life cycle, or performance improvement projects, account for approximately \$23 million, or 60 per cent, of the forecast capital additions for 2015:

- protective relaying & control system life cycle replacements and improvements (reference 9.2.2.1)

²⁸⁸ Exhibit 0003.00.EDTI-3539, application; exhibits 0031.00.EDTI-3539, 0032.00.EDTI-3539, 0033.00.EDTI-3539 and 0035.00.EDTI-3539 - business cases.

²⁸⁹ Exhibit 0005.00.EDTI-3539, EDTI responses to the AUC, Exhibit 0012.00.EDTI-3539, EDTI responses to CCA and Exhibit 0034.00.EDTI-3539, EDTI responses to the UCA.

²⁹⁰ Exhibit 3539-X0089, PDF page 30.

- SCADA upgrade (reference 9.2.2.3)
- communication system life cycle replacement and system improvement (reference 9.2.2.4)
- medium voltage (MV) switchgear replacement (reference 9.2.2.11)
- 500-kV air blast circuit breaker replacement (reference 9.2.2.12)
- MV switchgear addition – Rosssdale (reference 9.2.2.14)
- communication system upgrade (reference 9.2.2.18)

440. The south central transmission reinforcement project, also referred to as the Garneau expansion (reference 9.2.1.9), an AESO directed project, is the most significant forecast capital addition for the year 2016. This project accounts for approximately \$44 million or 67 per cent of the forecast capital additions for the year 2016. The second largest capital addition forecast for 2016 is protective relay & control life cycle replacements and improvements (reference 9.2.2.1) which are forecast to cost approximately \$4 million or six per cent of the forecast capital additions.

441. The following four projects, none of which are AESO directed projects, account for approximately \$36 million, or 64 per cent, of the forecast capital additions for 2017:

- protective relay & control system life cycle replacements and improvements (reference 9.2.2.1)
- MV switchgear addition – Rosssdale (reference 9.2.2.14)
- MV switchgear addition – Victoria (reference 9.2.2.15)
- life cycle replacement of 240-kV cable sections (reference 9.2.3.2)

Commission findings

442. The Commission has examined the evidence on the record of this proceeding respecting each of EDTI's capital projects. In having reviewed the forecast capital expenditures and capital additions, the business cases provided, responses to IRs, the oral testimony, and the argument and reply argument submitted by parties and other supplemental information, the Commission approves EDTI's forecast capital expenditures and capital additions for the years 2015-2017, for the purpose of calculating the forecast revenue requirement in the test years, subject to any adjustments arising from the findings for those capital projects specifically identified below.

10.3 AESO directed projects

443. EDTI described its AESO directed projects as projects assigned to it by the AESO that it is obligated to complete under Section 35 of the *Electric Utilities Act*. Direct assigned projects include any projects designated as critical transmission infrastructure pursuant to the *Transmission Regulation*, AR 86/2007. The costs associated with direct assigned projects are subject to deferral account treatment under EDTI's AESO directed projects deferral account.

444. EDTI stated that its AESO directed projects are categorized as growth projects. The substation relay room addition project, the north light rail transit (LRT) extension underground transmission project and the southeast LRT transmission asset project are also identified as growth projects, but are not AESO directed.

445. In EDTI's application, Table 9.2-1 identified three proposed AESO directed projects. They are the south central transmission reinforcement project (reference 9.2.1.9), the 240-kV gas

insulated switchgear (GIS) substation project (reference 9.2.1.10) and the Petrolia substation 1043L to 1139L conversion.

446. The Commission discusses its findings with respect to certain AESO directed projects below.

10.3.1 EDTI Genesee interface to HVDC converter station (reference 9.2.1.3)

447. The Genesee interface to high voltage direct current (HVDC) converter station (Genesee interface) is an AESO directed project forming part of the West Alberta transmission line project, which had been designated as critical transmission infrastructure under the *Electric Utilities Act* and was constructed by AltaLink.²⁹¹

448. In its application, EDTI stated that its portion of the Genesee interface project consisted of rerouting portions of the existing 1209L line to the Genesee 330P switchyard, upgrading protection and control and SCADA equipment at the Genesee 330P switchyard, and upgrading communication equipment at or near the Genesee 330P switchyard.

449. Specific to this project was a “tie in [of the] new 1203L section which was constructed by AltaLink from Sunny brook 510S to a point designation in the Functional Specification, section 7.3 (“Point A”).”²⁹²

450. EDTI stated in its application that both EDTI and AltaLink had assumed that AltaLink would own the new 1203L section. However, “in mid-2014 it was identified that the AUC’s Permit & Licence Nos. [U2012-662](#)^[293] and [U2012-663](#),^[294] as well as Connection Order [U2012-671](#),^[295] show the new section to be owned and operated by EDTI.”²⁹⁶

451. EDTI and AltaLink agreed that AltaLink would transfer ownership of this new section of the 1203L section to EDTI and invoice EDTI for the full cost of construction.²⁹⁷

452. In argument, EDTI summarized “the arrangement reached between EDTI and AltaLink [as being] consistent with Commission approvals, and as simple and logical.” EDTI explained as follows:

... the project includes removing of a portion of the old 1203L owned by EDTI and that, while the construction documents showed AltaLink building the entire line, the P&L [permit and licence] showed EDTI continuing to own the portion of 1203L close to the Genesee Substation. As EDTI owns the towers close to Genesee Substation, it was logical that EDTI continue to own the assets in this area. Therefore, EDTI and AltaLink agreed that it was logical that, in accordance with the PPS [proposal to provide service]

²⁹¹ Exhibit 3539-X0193, EDTI argument, paragraph 372, PDF page 164 of 259.

²⁹² Exhibit 0003.00.EDTI-3539, application, paragraph 1905, PDF page 668 of 900.

²⁹³ Transmission Line Permit and Licence No. U2012-662: AltaLink Management Ltd., Alter Transmission Line 1203L, Appendix 28 to Decision 2012-327, Proceeding 1045, Application 1607067, December 20, 2012.

²⁹⁴ Transmission Line Permit and Licence No. U2012-663: EPCOR Distribution & Transmission Inc., Alter Transmission Line 1203L, Appendix 29 to Decision 2012-327, Proceeding 1045, Application 1607067-1, December 20, 2012.

²⁹⁵ Connection Order No. U2012-671: AltaLink Management Ltd., EPCOR Distribution & Transmission Inc., Connect the EPCOR 500-kV Transmission Line 1203L to the AltaLink Sunnybrook 510S Substation, Appendix 37 to Decision 2012-327, Proceeding 1045, Application 1607067-1, December 20, 2012.

²⁹⁶ Exhibit 0003.00 EDTI-3539, application, paragraph 1911, PDF page 670 of 900.

²⁹⁷ Exhibit 0003.00.EDTI-3539, application, paragraph 1911, PDF page 670 of 900.

and P&L, AltaLink would construct this portion of the project and then sell the assets to EDTI.²⁹⁸

453. EDTI confirmed during the hearing that costs related to the 1203L section would include the application of both a one per cent capitalized overhead rate by EDTI for the project, consistent with its treatment of all AESO directed projects, as well as a three per cent overhead charge in the final sales invoice that EDTI expected to receive from AltaLink.

454. EDTI's updated information showed that this project was capitalized in 2014 in the amount of \$12.76 million, compared to the 2014 approved amount of \$12.57 million.²⁹⁹ However, during the hearing, EDTI witnesses stated that there may be other post-closing construction adjustments required. These include, for example, the three per cent overhead on AltaLink's final invoice related to the sale of the 1203L section to EDTI.³⁰⁰

455. EDTI stated the AltaLink construction and arrangement for the sale of the 1203L section to EDTI resulted in the most efficient and least cost option available, given the economies of scale that could be achieved by AltaLink because it was already constructing the larger transmission line and had more expertise in the design and construction of this type of transmission line.³⁰¹

456. No party expressed concerns with the Genesee interface to HVDC converter station project or the component of the project related to the 1203L section.

Commission findings

457. The Commission has examined the evidence related to the Genesee interface to HVDC converter station including the confusion related to the ownership of the 1203L section. The Commission acknowledges EDTI's submission that the construction arrangement with AltaLink resulted in the realization of certain cost benefits for the project. The Commission finds that the costs incurred to date for the Genesee interface to HVDC converter station are reasonable for the purposes of determining revenue requirement in this proceeding but remain subject to final true-up as part of EDTI's direct assigned deferral account process.

458. The Commission is concerned that EDTI appears not to have been aware of Permit & Licence Nos. U2012-662 and U2012-663 or Connection Order U2012-671 until mid-2014. The Commission directs EDTI in its next GTA to describe the process used to monitor the status of permits, licences and orders it receives from the Commission.

10.3.2 South central transmission reinforcement (reference 9.2.1.9)

459. In its application, EDTI described the south central transmission reinforcement (south central) project (also referred to as the Garneau expansion) as being a proposed AESO directed project that is required to address increasing capacity needs at the existing Garneau substation in south central Edmonton. The project consists of installing an additional 2.7 km of cross-linked poly-ethylene (XLPE) underground cable circuit between the existing Garneau and Rosedale substations. The cable would be rated at 240 kV, but operate initially at 72 kV.

²⁹⁸ Exhibit 3539-X0193, EDTI argument, paragraph 374, PDF page 164 of 259.

²⁹⁹ Exhibit 3539-X0086, CWIP continuity schedule updated for 2014 actuals.

³⁰⁰ Exhibit 3539-X0138, undertaking at Transcript, Volume 2, page 398.

³⁰¹ Transcript, Volume 2, pages 395-396.

460. EDTI stated that in January 2014, the AESO issued a functional specification for the project to EDTI transmission, to which EDTI responded by preparing a PPS dated October 24, 2014.

461. At the time EDTI filed its GTA, it anticipated that the AESO would file a needs identification document (NID) for the project with the Commission in late 2014, to be followed by EDTI filing a facility application with the Commission requesting a P&L to construct and operate the south central project. EDTI had expected to receive the P&L by mid-2015 and complete and put the project into service in 2016.

462. In response to IRs, EDTI confirmed that it now anticipated the AESO would file its NID in 2015. As a result, the south central project was expected to be completed and put into service in 2017. EDTI stated that the “work originally forecast to be completed in 2015 is now expected to be completed in 2016, the work originally forecast to be completed in 2016 is now expected to be completed in 2017 and the work originally forecast to be completed in 2017 is now expected to be completed in 2018.”³⁰²

463. EDTI indicated that while it had not calculated the probability-adjusted additions to rate base for the project, it believed at the time the IR responses were prepared in February 2015, there was an equal probability that the bulk of the project work could be completed, and the associated costs of \$43.73 million incurred, either before the new forecast completion date of 2017 or after the new forecast completion date of 2017.³⁰³

464. EDTI was not able to confirm whether the south central project is a distribution driven transmission project such that a contribution would be anticipated by EDTI transmission from EDTI distribution. EDTI stated that the project was currently considered an AESO “system project” and the classification was under review by the AESO. EDTI also stated that if the project were designated as an AESO directed project, it would be subject to deferral account treatment.

465. During the hearing, EDTI stated its expectation that the AESO would provide its decision on whether the south central project would be a system or distribution driven project in the coming months, but was not confident that the AESO decision would be made prior to the release of the Commission decision respecting EDTI’s GTA.

³⁰² Exhibit 3539-X0005, EDTI-AUC-2015FEB06-033, PDF page 130 of 513.

³⁰³ Exhibit 3539-X0012, EDTI-CCA-2015FEB06-015, PDF pages 58-59 of 310.

466. The Commission has summarized information from EDTI's application respecting the south central project in the following three tables:

Table 32. EDTI south central transmission reinforcement project rate base additions 2012-2017 as applied- for and updated for 2014 actuals

	A 2012 A	B 2013 D	C 2013 A	D 2014 D	E 2014 UF	F 2014 A	G 2015 IF	H 2016 F	I 2017 F
	(\$ million)								
Capital expenditures	0.23	0.74	0.63	0.76	1.25	1.15	4.40	36.60	1.94
Opening CWIP balance	0.76	0.98	.98	1.72	1.62	1.62	2.73	7.13	-
Closing CWIP balance	0.98	1.72	1.62	2.48	2.87	2.73	7.13	-	-
Total capital additions to rate base	-	-	-	-	-	-	-	43.73	1.94

Source: Exhibit 3539-X0086, CWIP continuity schedule updated for 2014 actuals – South central transmission reinforcement project.

Table 33. EDTI south central transmission reinforcement project rate base additions 2012-2017 as applied- for with 2014 updates and adjusted for most recent work flow expectations

	A 2012 A	B 2013 D	C 2013 A	D 2014 D	E 2014 A	F 2015 IF	G 2016 F	H 2017 F	I 2018 F
	(\$ million)								
Capital expenditures	0.23	0.74	0.63	0.76	1.15	-	4.40	36.60	1.94
Opening CWIP balance	0.76	0.98	.98	1.72	1.62	2.73	2.73	7.13	-
Closing CWIP balance	0.98	1.72	1.62	2.48	2.73	2.73	7.13	-	-
Total capital additions to rate base	-	-	-	-	-	-	-	43.73	1.94

Source: Exhibit 3539-X0086, CWIP continuity schedule updated for 2014 actuals with the work flow shown as anticipated and described in Exhibit 0005.00.EDTI-3539, AUC information request EDTI-AUC-2015FEB06-033.

Table 34. EDTI south central transmission reinforcement project rate base additions 2012-2017 as revised in undertaking on June 12, 2015

	A 2012 A	B 2013 D	C 2013 A	D 2014 D	E 2014 A	F 2015 IF	G 2016 F	H 2017 F
	(\$ million)							
Capital expenditures	0.23	0.74	0.63	0.76	1.15	0.91	22.07	26.08
Opening CWIP balance	0.76	0.98	.98	1.72	1.62	2.73	1.68	23.75
Closing CWIP balance	0.98	1.72	1.62	2.48	2.73	1.68	23.75	-
Total capital additions to rate base	-	-	-	-		1.96	-	49.82

Source: Exhibit 3539-X0128.01, CWIP continuity schedule – South central transmission reinforcement project updated during hearing as undertaking (updated Exhibit 3539-X0086).

467. As evidenced in the above tables, EDTI is now forecasting that the south central project will cost \$51.78 million (\$1.96 million + \$49.82 million), which is an increase of \$6.11 million, or a 13.3 per cent increase in costs, between the time IR responses were submitted on February 6,

2015, and the oral hearing in June 2015. The reasons for the forecast cost increase were not provided by EDTI.

468. EDTI confirmed in testimony that the manager for the south central project believed the project could be constructed from start to finish over the span of one and a half years to two years and thus completed in 2017,³⁰⁴ despite as of mid-June 2015, a NID had not been submitted by the AESO.³⁰⁵ Nor had any financial commitments for long-lead materials such as cable or GIS for the project been made.³⁰⁶

469. EDTI concluded that the south central project, subject to the receipt of the necessary Commission approvals, will proceed over the test period and that the updated capital addition forecast of the project costs should be approved.

Commission findings

470. The Commission is concerned by the many uncertainties related to this project. With respect to forecast costs, the increase of \$6.11 million in project costs was not adequately supported or explained by EDTI. Additionally, EDTI did not explain why the anticipated pattern of spending for this project, as presented in tables 32, 33 and 34 has changed so significantly. The Commission finds this evidence raises concerns about the reliability of EDTI's forecast, including the quantum of forecast costs and EDTI's expectations with respect to the work-flow and completion of the project.

471. The timing of the project construction is uncertain because the AESO has not yet submitted a NID application to the Commission for approval of this project. There is the possibility that the NID application will be further delayed, not approved or varied. There is also uncertainty regarding the classification of the project due to a lack of information as to whether the project will be a system or distribution driven project.

472. The Commission finds that EDTI has not adequately supported the reasonableness of the forecast capital expenditures and additions for this project during the test period. Based on the foregoing, the Commission is not prepared to approve EDTI's forecast revenue requirement related to this project for the test period.

473. The Commission directs EDTI to remove all forecast capital expenditures and additions, and related costs with respect to the south central project from its forecast 2015-2017 revenue requirement, and reflect this direction in its compliance filing to this decision.

10.3.3 240-kV GIS substation (reference 9.2.1.10)

474. The 240-kV GIS substation project was described by EDTI in its application as a proposed AESO directed project that is required to improve the reliability of the transmission system in Edmonton. The proposed project would convert certain areas to a closed loop system by installing a new point of delivery (POD) near EDTI's Argyll transfer station. Doing so would minimize the transmission line costs associated with the replacement of the 72RS5 underground

³⁰⁴ Transcript, Volume 2, pages 420-421.

³⁰⁵ Transcript, Volume 2, page 420.

³⁰⁶ Exhibit 3539-X0188, response to undertaking at Transcript, Volume 7, page 1328.

cable which, in addition to the Strathcona substation itself, is nearing the end of its useful service life.³⁰⁷

475. No capital additions are forecast for this project in the test years, however EDTI has forecast capital expenditures in the amount of \$2.2 million, \$0.6 million and \$12.7 million for the years 2015, 2016 and 2017, respectively.

476. Concurrent with the anticipated AESO NID filing, which EDTI expects will occur in late 2016, EDTI will file a facility application requesting a P&L to construct and operate the proposed facilities. EDTI expects to receive the required P&L decision by mid-2017 and complete the project and put it into service in late 2018.³⁰⁸

477. During the hearing, EDTI advised that it submitted a system access service request to the AESO in March 2015 and is currently at Stage 0 with respect to the project.³⁰⁹

478. There is uncertainty as to whether the project will be considered as a system project or a distribution project that would be subject to a contribution from EDTI's distribution function.

Commission findings

479. The Commission is not convinced that the scheduled timing of the 240-kV GIS substation project has been adequately supported by EDTI on the record of this proceeding.

480. The Commission is concerned the necessary approvals may not be obtained as anticipated, which may cause significant time delays that may, in turn, result in the forecast capital expenditures occurring outside the test period. EDTI's statement that the project remains, as of mid-June 2015, at Stage 0, some 13 weeks after having submitted its SAS request to the AESO in March 2015, raises concerns regarding possible project delays. Further, there is a lack of information as to whether the project will be a system or distribution driven project.

481. Based on the foregoing, the Commission is not prepared at this time to include in revenue requirement, the costs associated with the forecast capital expenditures for this project during the test period, as proposed by EDTI.

482. The Commission directs EDTI to remove all forecast capital expenditures and related costs with respect to the 240-kV GIS substation project from its forecast 2015-2017 revenue requirement, and reflect this direction in its compliance filing to this decision.

10.4 Non-AESO directed growth projects and performance improvement projects

10.4.1 Substation [building] relay room additions (reference 9.2.2.23)

483. This is a new program which consists of adding additional substation relay rooms to EDTI transmission substations. The additional relay rooms are required to address the capacity constraint,³¹⁰ risk of water damage³¹¹ and risk of arc flash³¹² concerns.³¹³

³⁰⁷ Exhibit 3539-X0193, paragraphs 391-395.

³⁰⁸ Exhibit 0003.00.EDTI-3539, application, paragraph 1988, PDF page 690 of 900.

³⁰⁹ Transcript, Volume 2, page 381.

³¹⁰ Additional relay panels are required to meet load growth, to implement EDTI's protective relay and control system life cycle replacement and improvements program and SCADA system life cycle replacement and

484. In this test period, EDTI is proposing to add additional relay rooms to Kennedale substation in 2015, Victoria substation in 2016 and Meadowlark substation in 2017. The additional relay room at Kennedale substation is required to complete the transformer differential protection life cycle replacement, the MV bus differential protection life cycle replacement and life cycle replacements of transmission line distance protections, as well as to accommodate future growth. The additional relay room at Victoria is required to complete the SCADA RTU life cycle replacement and improvements project, and to accommodate future growth. The additional relay room at Meadowlark is required to complete its 72-kV breaker fail protection upgrade project and to accommodate future growth.³¹⁴

485. EDTI expanded on the capacity constraint driver in response to an IR stating that the increased number of relay panels is not due to transmission capacity increases due to load growth.³¹⁵ It is primarily due to advancements in technology (i.e., addition of substation equipment monitoring equipment), the need to address employee safety issues (i.e., relocation of relays from switchgear cells to remote relay panels), and to meet Alberta Reliability Standard requirements. EDTI proposed that the new relay rooms will be installed on the main floor of the substation buildings, which requires that the existing substation buildings be expanded.³¹⁶ The building expansions will be within the current substation footprint.³¹⁷

486. EDTI first became aware of the space issues at Victoria substation in 2014.³¹⁸ EDTI is proposing to expand Victoria as part of the MV switchgear addition project.³¹⁹ The expansion will also provide space to move the existing relay panels, which are currently located in the basement of the substation or in the vicinity of arc flash hazards. Those relocations will not be undertaken in the current test period.³²⁰ Relocating the existing relay panels out of the substation basements is anticipated to be completed at the time of relay life cycle replacement which will occur 10 to 15 years after installation.³²¹ Until that time, the additional space in the new relay rooms will not be utilized and after the relocation of the panels, the space they currently occupy in the basement will remain empty.³²²

487. The proposed building expansion will not require the purchase of land,³²³ will be completed within a live facility without obstructing substation access or impacting existing cable

improvements program and the existing relay rooms cannot accommodate additional relay panels without being in violation of the Alberta Building Code 2006 in regards to egress pathway to existing room space.

³¹¹ Due to space constraints in the substation, new relay panels were previously installed in the building basement. These basements are at risk for flooding which could result in damage to the panel. The proposed solution is to move these relay panels to the main floor of a substation.

³¹² Relay panels at many existing substations are located in the vicinity of other equipment which represents an arc flash hazard which then poses a risk to personnel safety. Previously, EDTI had installed barriers to protect personnel and equipment but a more effective solution would be to move the relay panels away from arc flash hazards.

³¹³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 5, 8 and 9, PDF pages 254-255 of 433.

³¹⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 11, PDF page 256 of 433.

³¹⁵ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-046(a), PDF page 326 of 429.

³¹⁶ Exhibit 0003.00.EDTI-3539, application, paragraphs 2370-2378, PDF pages 796-798 of 900.

³¹⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, Figures T-CBC-15-3, 15-4 and 15-5, PDF pages 258-260 of 433.

³¹⁸ Transcript, Volume 1, page 206.

³¹⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 17, PDF page 226 of 433.

³²⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 256 of 433.

³²¹ Transcript, Volume 3, page 583.

³²² Transcript, Volume 3, pages 583-584.

³²³ Transcript, Volume 3, page 582.

ducts or other underground services, and will make use of existing building systems.³²⁴ EDTI confirmed that it does not have definitive plans to expand the substation further in the longer term, however, a detailed analysis has not been done.³²⁵

488. In response to a Commission IR, EDTI provided information on the major flooding events for all of its substations. EDTI cautioned that the minor flooding events, which are not recorded, could also damage equipment in the basement of substations. Major flooding events were recorded at Kennedale in October 2013, at Meadowlark in November 2013 and at Victoria in December 2004, May 2008 and November 2013. None of the flooding appears to have significant costs recorded or were recorded as “general substation cleaning.”³²⁶

489. The forecast capital additions for this program are \$1.44 million in 2015 for Kennedale, \$0.76 million in 2016 for Victoria and \$1.41 million in 2017 for Meadowlark.³²⁷ The largest component of this cost forecast is contractor costs.³²⁸ The difference in forecast costs between test years is due to the scope of work, the size of the building, and the difficulties that each location poses.³²⁹ EDTI confirmed that the cost forecasts include adequate heating, ventilation and air conditioning (HVAC) systems to prevent overheating of these panels, which is a concern with existing relay rooms and is discussed further in Section 10.5.6.

490. EDTI evaluated five alternatives for dealing with the capacity issues at each substation: (1) do nothing, (2) reorganize existing relay rooms, (3) reorganize the substation, which would involve reorganizing the substation so an additional relay room could be constructed without expanding the substation, (4) expand the substation and (5) use the existing substation expansion, at Victoria substation. EDTI rejected the first alternative on the basis that the current relay rooms do not have sufficient capacity to accommodate the additional relay panels which are required for the proposed protection and controls (P&C) upgrades. EDTI similarly rejected the second alternative because the current relay rooms are at full capacity and there is no feasible method to reorganize the existing relay rooms to provide sufficient space to accommodate the additional relay panels. EDTI rejected the third alternative on the basis that the only two methods to reorganize the substations to accommodate additional relay panels are to install the relay panels in the basement or in the vicinity of equipment that could represent an arc flash hazard, which would not address two of the concerns which are to be addressed by this program. For all these reasons, EDTI proposed to proceed with the alternative to expand the substation buildings to add new relay rooms that will accommodate additional relay panels.³³⁰

491. EDTI rejected alternative (5), to use the existing substation expansion at Victoria and install the additional relay panel in the proposed new substation building, for four reasons. To combine this project with the Victoria expansion would require (1) that EDTI reroute the existing communication cables to the new building, (2) changes to the proposed new building’s current design which does not have space for additional relay panels on the main floor (3) housing the P&C and SCADA communications in separate physical locations, which is inefficient, and (4) the net present value (NPV) for this alternative is more costly than the fourth alternative.

³²⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 11, PDF page 256 of 433.

³²⁵ Transcript, Volume 3, pages 582-583.

³²⁶ Exhibit 3539-X0005, EDTI-AUC-2015-FEB06-037, PDF pages 136-137 of 413.

³²⁷ Exhibit 3539-X0086, CWIP updated for 2014 actuals, row 53.

³²⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-15-1, PDF page 261 of 433.

³²⁹ Transcript, Volume 2, page 350.

³³⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 262-266 of 433.

492. In the evidence submitted by the UCA, Mr. Bell stated that there is no detailed quantitative analysis of the impact of not pursuing this project, from a service quality or safety perspective. He also noted that EDTI has indicated that it does not keep records of surplus available space and that it installed additional relay panels in the basement of substations. Mr. Bell submitted that there is no evidence as to why this work was not done earlier or could not be deferred for one or more test periods.³³¹ Mr. Bell recommended that the Commission find that EDTI has not adequately demonstrated why the substation building relay room additions project is required in the test period and that the forecast capital additions be denied.³³²

493. In its rebuttal evidence, EDTI explained that while it does not maintain a documented registry of surplus relay space within its substation buildings, it fully studies space constraints of its substations. EDTI reiterated that this program cannot be deferred to the next GTA as it would result in EDTI being unable to carry out the life cycle replacement of transformer and MV bus differential protection schemes, SCADA MTU life cycle replacement and 72-kV breaker failure protection relaying upgrades which rely on additional space to add the proposed new relays. In EDTI's view, the information provided in the business case and in response to IRs adequately demonstrate that the project is required as proposed.³³³

494. In reply to EDTI's argument, the UCA pointed out that without a record of surplus space, there is no way to answer the question of whether there were options to complete the work earlier as part of another project and/or at a lower total cost.³³⁴

Commission findings

495. The Commission has considered the evidence in relation to the proposed growth program for substation relay room additions and finds that in the test period, this project is needed in order to, in turn, complete the SCADA projects (which are discussed in sections 10.5.3 and 10.5.4). The Commission is satisfied that substation relay room additions are being completed in advance of the SCADA projects, which drive this program, and finds the proposed schedule for these projects to be reasonable. The Commission is also satisfied that, based on the evidence provided, the scope of work for this project is such that this project can reasonably be expected to be completed as scheduled. The Commission finds that there is sufficient evidence to approve the test period forecast capital additions for this project for the purposes of determining EDTI's revenue requirement.

496. The Commission does not, however, give a general approval for this program in future test periods. The rationale for adding additional relay rooms on the basis of capacity constraints, risk of water damage and arc flash risk will be evaluated in future applications on a case-by-case basis for each substation. The Commission, at this time, does not consider that the need for additional relay rooms is sufficient on the basis of the risk of water damage alone, as demonstrated by the infrequent flooding events recorded and the minimal costs associated with those flooding events.³³⁵ The Commission also finds that the arc flash risk associated with the proximity of relay panels to other substation equipment is not sufficiently demonstrated in this application. If EDTI is to rely on concerns regarding the risk of arc flash in future applications,

³³¹ Exhibit 3539-X0051, Q&A 25, page 15.

³³² Exhibit 3539-X0051, Q&A 27, page 17.

³³³ Exhibit 3539-X0071, EDTI rebuttal, Q&A53, PDF pages 70-72 of 82.

³³⁴ Exhibit 3539-X0196, UCA reply argument, PDF page 15 of 19.

³³⁵ Exhibit 3539-X0005, EDTI-AUC-2015-FEB06-037, Table EDTI-AUC-2015FEB06-037-1, PDF pages 136-137 of 513.

EDTI is directed to provide additional information for relay room additions that demonstrates there is a genuine arc flash risk and that the solution of installing a protective barrier is not feasible or preferable.

10.4.2 Capitalization of the SEAS project and Quanta Technology reports (reference 9.2.3.6)

497. In its application, EDTI stated it had completed a detailed engineering review of its entire transmission infrastructure assets (including aerial transmission, underground cable transmission and substations), for the purpose of developing a comprehensive and coordinated asset strategy as a solution to issues associated with EDTI's aging infrastructure and implications of future growth requirements. The review was conducted by Quanta Technology, LLC (Quanta) and was often referred to as the SEAS report, or more fully described as *the system planning load and sustainability study and equipment life and condition assessment for transmission lines and substations report*. In its application, EDTI included this project within its performance improvement category.

498. EDTI first identified plans to carry out an assessment study of its overall transmission system and to develop a plan which would include a comprehensive and overall coordinated asset strategy with a view to the longer term in its 2010-2011 GTA. EDTI had requested approval to carry out a detailed engineering review and had forecast expenditures of \$1.0 million in 2010 related to the proposed SEAS report at that time.³³⁶

499. EDTI discussed the scope of the transmission assessment study in its 2012 GTA. EDTI stated that during the preliminary stages of the engineering review, it had determined a more comprehensive review of EDTI's entire transmission infrastructure was required. Based on concerns related to aging infrastructure and forecast growth requirements, EDTI wished to determine the most effective and efficient solutions.³³⁷

500. EDTI explained the revised scope of the engineering review included the following four categories:

1. System load forecast, system studies and transmission voltage study
2. Underground transmission OFPT cable condition assessment
3. Aerial transmission line assessment
4. Substation and terminal station assessment

501. EDTI stated it expected that the detailed engineering review would result in future life cycle replacement projects and proposed to add the cost of the engineering study to rate base in conjunction with the addition to rate base of the associated project costs.

502. EDTI engaged Quanta in the summer of 2011, following a request for proposal (RFP) process,³³⁸ to review the condition of EDTI's transmission system assets and make recommendations on their life cycle replacement, as well as recommendations on how the

³³⁶ Proceeding 437, Exhibit 0065.00.EDTI-437, EDTI 2010-2011 DFO and TFO application, paragraphs 52-55, PDF page 15 of 259.

³³⁷ Proceeding 1596, Exhibit 0003.00.EDTI-1596, EDTI 2012 TFO application, paragraphs 4649-4662, PDF pages 1413-1414 of 1520.

³³⁸ Exhibit 0003.00.EDTI-3539, application, paragraphs 2523-2524, PDF pages 834-835 of 900.

development of EDTI's transmission infrastructure should proceed to meet its future operating and load carrying requirement.³³⁹

503. In Decision 2012-272, respecting EDTI's 2012 GTA, the Commission stated the following:

296. The Commission agrees in principle with EDTI's proposal to transfer the costs of the system planning load and sustainability study to rate base in conjunction with the addition to rate base of life-cycle expenditures that arise out of the study. As EDTI is not transferring the costs to rate base at this time, a review of the project costs incurred will be made at the time the request for transfer to rate base is submitted.

504. As of the end of 2012, on an actual basis, EDTI had incurred \$1.2 million in expenditures related to the SEAS project and was forecasting an additional \$0.5 million and \$0.3 million in expenditures in the years 2013 and 2014, respectively. Therefore, the total anticipated costs, including allowance for funds used during construction (AFUDC), for this project at the time of EDTI's 2013-2014 GTA was \$2.0 million.³⁴⁰

505. EDTI received the Quanta reports in June, 2013. Between the time of receiving the reports and submitting this application, EDTI undertook a review of the reports and recommendations internally and with the AESO.³⁴¹

506. At the end of 2014, on an actual basis, EDTI had incurred \$1.6 million in expenditures related to this project which included \$0.21 million³⁴² related to AFUDC. In its 2015-2017 GTA, EDTI proposed to capitalize this amount into rate base, in USA Account 358 – underground conduit, conductors and devices, in the year 2015³⁴³ and amortize the costs in conjunction with a proposed average service life for this account of 45 years. EDTI proposed that an amortization period of 45 years recognizes the longer life nature of the projects associated with the SEAS report.³⁴⁴

507. Six reports were prepared by Quanta for EDTI Transmission, which were filed on the record of this proceeding as appendices G8 to G13 to the application.³⁴⁵ The scope of work for the SEAS report was defined by EDTI and was provided on the record of this proceeding as Appendix G15.³⁴⁶ The scope of work was prepared in 2010 prior to the RFP³⁴⁷ and the scope of work provided on the record was the same as that which was included with the RFP.³⁴⁸ In the scope of work document, EDTI stated that a comprehensive and formal study of EDTI's transmission system must be undertaken. The study would consider not only the age and condition of the system, but would provide a holistic management plan and an optimization and modernization strategy.

³³⁹ Exhibit 0003.00.EDTI-3539, application, paragraph 2388, PDF page 800 of 900.

³⁴⁰ Proceeding 2758, Exhibit 0060.00.EDTI-2758, Schedule B-1 (CWIP continuity schedule), reference 9.2.3.6.

³⁴¹ Exhibit 0003.00.EDTI-3539, application, paragraph 106, PDF page 50 of 900.

³⁴² Exhibit 3539-X0183, undertaking at Transcript, Volume 6, page 1245.

³⁴³ Exhibit 3539-X0086, CWIP updated for 2014 actuals, reference 9.2.3.6.

³⁴⁴ Transcript, Volume 6, pages 1243-1244.

³⁴⁵ Exhibits 0047.00.EDTI-3539 to 0052.00.EDTI-3539, appendices G-8 to G-13.

³⁴⁶ Exhibit 0054.00.EDTI-3539, Appendix G-15.

³⁴⁷ Transcript, Volume 6, page 1125.

³⁴⁸ Transcript, Volume 6, page 1126.

508. The Quanta witness confirmed that as part of the deliverables for the SEAS study, Quanta prepared business cases which were provided to EDTI. However, those business cases were not provided on the record of this proceeding as they pertain to future projects.³⁴⁹

509. Each of the four categories for the scope of work (underground cables and aerial lines were split) was addressed in a separate report and Quanta also prepared a project summary and a transmission planning assessment.

510. The report entitled Project Summary contained an overall description of the methodology used and a summary of the conclusions and recommendations. As part of the Project Summary, Quanta reviewed four options to upgrade or modify the transmission system to meet the forecast load requirements into 2040. These options were:

- (1) operating the 72-kV system as is,
- (2) replacement of the 72-kV cables with new 1000A 72-kV cables and selected substation upgrades,
- (3) conversion of Garneau, Hardisty, Rossdale, and Strathcona substations to 240-kV supplies and upgrade 72-kV cable supplies to the existing 72-kV substations and
- (4) conversion of Garneau, Rossdale, Strathcona, and Victoria Substations to 240-kV supplies, construction of a new 240/72-kV switching station north of Victoria, and new and upgraded 72-kV cable supplies to the existing 72-kV sub-stations.³⁵⁰

511. While EDTI presented Table 9.2.3.6-1 in the application as showing projects which are recommended by the SEAS reports, EDTI, in response to an undertaking, confirmed that only two projects applied for in the test period were specifically undertaken as a result of the SEAS report recommendations (i.e., the projects had not been done or planned to be done prior to receiving the reports): installation of soil temperature monitors as part of the miscellaneous transmission underground project and the RS5 cable replacement project as part of the new Argyll substation.³⁵¹

512. In response to an IR, EDTI explained that it relies on the SEAS reports for guidance in ensuring that EDTI's existing transmission infrastructure is capable of meeting future operating and loading requirements and to validate EDTI's proposed life cycle replacement projects and maintenance activities over the short and long terms.³⁵²

513. Quanta's witness confirmed that EDTI's use of the SEAS reports as a long-term plan is consistent with what other utilities do with these types of reports.³⁵³

514. In response to Commission counsel, the Quanta witness affirmed that the SEAS reports could be relied on for the purposes of projects proposed in the test period and are considered to be an adequate guideline for five to eight years. The witness noted however, that the reports

³⁴⁹ Transcript, Volume 6, pages 1133-1134.

³⁵⁰ Exhibit 0047.00.EDTI-3539, Appendix G-8, PDF pages 9-13 of 57. In the hearing, at Transcript, Volume 5, pages 912- 913, EDTI's witness confirmed that EDTI was pursuing Option 4 as its long-term plan.

³⁵¹ Exhibit 3539-X0181, undertaking at Transcript, Volume 6, page 1105.

³⁵² Exhibit 3539-X0012, EDTI-CCA-2015FEB06-017(a), PDF page 238 of 310.

³⁵³ Transcript, Volume 6, pages 1107-1108.

should be updated and reviewed for changing conditions. An update and review would be part of the annual planning process; not a formal review.³⁵⁴

515. In argument, EDTI summarized its use of the SEAS reports to inform capital maintenance and life cycle replacement programs, to ensure that it does not undertake work that will prove to be redundant and to provide the information necessary to advise the AESO of the condition and capability of EDTI's transmissions system, expected load growth and recommendations as to the appropriate development and modifications to its system to meet anticipated growth and system reliability requirements.³⁵⁵

516. The UCA and the CCA did not address the SEAS reports, including EDTI's proposed capitalization of the reports in argument or reply.

Commission findings

517. The Commission has reviewed the SEAS reports and is satisfied that they have provided useful reference material to EDTI, which has informed its comprehensive and coordinated asset strategy for both the near and longer term.

518. However, the Commission is not convinced that EDTI's proposal to capitalize the costs associated with the SEAS report into USA Account 358 – underground conduit, conductors and devices, and amortize the costs over 45 years, is reasonable.

519. The Commission considers that despite the fact that any associated capital projects stemming from EDTI's use of the SEAS reports may result in assets with average service lives of 45 years, the Quanta witness was of the opinion that the SEAS reports themselves would provide adequate guidance to EDTI for only five to eight years. Accordingly, the Commission finds five years to be a more reasonable period over which to amortize the value of the SEAS reports.

520. On that basis, the Commission directs EDTI to capitalize the applied-for costs of the SEAS reports into a separate regulatory asset account, and amortize the associated costs over a period of five years.

10.5 Life cycle projects

10.5.1 Background and common matters

521. Life cycle projects relate to replacing aging infrastructure to ensure the continuation of safe, reliable and economic operation of the interconnected electric system. This includes the replacement of:

- assets that have either failed or been destroyed
- assets that are believed to be prone to a disruptive failure
- assets that are nearing the end of their lives and can no longer be reliably or cost effectively maintained or repaired (e.g., due to the unavailability of parts or lack of support from the manufacturer)
- assets that are nearing the end of their lives and cannot be cost effectively replaced through refurbishment or other life extending investment

³⁵⁴ Transcript, Volume 6, pages 1130-1132.

³⁵⁵ Exhibit 3539-X0193, PDF page 138 of 259.

- assets that need to be replaced due to unforeseen circumstances³⁵⁶

522. For the two years from 2013 to 2014, the decision amounts for forecast life cycle capital additions totalled \$22.62 million and \$26.41 million respectively, with actual life cycle capital additions of \$21.68 million and \$27.26 million respectively.

523. EDTI's planned life cycle capital additions in the test period include:

Table 35. Breakdown of life cycle project types and forecast costs

Category of project (and number of related projects)	2015F	2016F	2017F
	(\$ million)		
Transmission station equipment life cycle replacement (16)	26.86	15.02	43.52
Underground transmission line life cycle replacement (3)	1.23	3.33	6.99
Aerial transmission line reconfiguration and life cycle replacement (1)	0.33	0.34	0.34
Computer hardware and software equipment life cycle replacement (3)	0.20	0.18	0.70
Other life cycle replacement (vehicles and tools) (2)	0.78	0.94	0.72
Total	29.40	19.81	52.27

524. The forecast cost of life cycle project additions is \$2.15 million higher (rounding difference) in 2015 than actual additions in 2014, \$9.59 million less in 2016 than the 2015 forecast and \$32.46 million higher in 2017 than the 2016 forecast.³⁵⁷ This is largely due to the MV switchgear additions projects at Rosedale and Victoria substations, and the 240-kV cable sections life cycle replacement project not being capitalized until 2017.³⁵⁸

525. The life cycle project additions forecast in the test period are explored individually in the sub-sections below following a discussion of some common matters related to life cycle projects.

10.5.1.1 Cost forecast approach

526. EDTI uses a similar forecast cost approach for all life cycle projects. The forecast capital expenditures for each project in an ongoing program are based on:

- EDTI's cost estimates for engineering, materials, project management, construction, contractor supervision where required, testing and commissioning into service.
- Where available, historical actual costing information for similar projects constructed in previous years.³⁵⁹

527. In its argument, EDTI stated that it uses a "bottom up" approach to forecasting where each project cost estimate is based on the particular work required for that particular project.³⁶⁰

³⁵⁶ Exhibit 0003.00.EDTI-3539, application, paragraph 228, PDF page 101 of 900.

³⁵⁷ Exhibit 3539-X0086, CWIP updated for 2014 actuals.

³⁵⁸ Exhibit 3539-X0086, CWIP updated for 2014 actuals. An amount of \$26.33 million will be capitalized in 2017 for the Rosedale and Victoria MV switchgear additions projects and \$6.05 million will be capitalized in 2017 for the life cycle replacement of 240-kV cable sections. The 240-kV cable sections life cycle replacement project is forecast to begin in 2016. The MV switchgear addition project at Rosedale has had capital expenditures accumulating in CWIP since 2012 and the MV switchgear addition project at Victoria has had capital expenditures accumulating in CWIP since 2014.

³⁵⁹ Exhibit 0030.00.EDTI-3539, for example, paragraph 55, PDF page 17 of 433.

³⁶⁰ Exhibit 3539-X0193, EDTI argument, paragraph 289, PDF page 122 of 259.

EDTI also stated that forecasting using historical averages may not be reasonable as historical expenditures and additions vary significantly from year to year, and the number of types of projects in a program vary from year to year.³⁶¹

528. Some projects, which do not have a defined scope at the time of preparing estimates for the test period, are forecast using a three-year historical average. These projects were defined as bucket projects during the hearing and were discussed earlier in Section 6.

529. Except in cases where EDTI has provided additional detail beyond that described above for program forecast costs, an explanation of the methodology will not be reiterated in the sub-sections below for individual programs. In the following sections, there will be little discussion of the year-to-year variances in forecast costs because of EDTI's statement that the project costs are forecast using a "bottom up" approach and therefore are not related to the previous year's forecast.

10.5.1.2 Cost minimization strategy

530. EDTI takes the following steps to minimize the cost of capital expenditures wherever possible in its projects:

- EDTI purchases materials and equipment utilizing a competitive bid process
- EDTI uses industry standard materials
- existing designs and drawings from previous similar projects are used, where possible, to reduce the engineering time and cost for projects
- EDTI's project management office coordinates construction scheduling and cost controls
- where possible, work will be coordinated with other projects or maintenance activities to minimize costs³⁶²

531. In the hearing, EDTI's witness confirmed that these steps are taken with respect to all capital projects.³⁶³ EDTI's witness also confirmed that EDTI has a process in place to verify that these cost minimization steps are taken and are effective. This includes review by senior management at the project initiation stage, and the project forecast costs and budgets being reviewed annually by the senior manager and the director at a budget review meeting.³⁶⁴

532. Except in cases where EDTI has provided additional detail beyond that described above for the steps taken to minimize program costs, an explanation of those steps will not be reiterated in the sub-sections below for individual programs.

10.5.1.3 Use of contractors

533. In response to a Commission IR regarding what costs EDTI incurs for contractors, EDTI provided an explanation of the line items in the Forecast Cost Summary tables provided in each business case³⁶⁵ which break out the components of projects costs such as labour, engineering, materials, contractor, etc. The labour cost line item only includes the costs for internal resources

³⁶¹ Exhibit 3539-X0193, EDTI argument, paragraph 400, PDF page 171 of 259.

³⁶² Exhibit 0003.00.EDTI-3539, application, paragraph 2020, PDF page 701 of 900.

³⁶³ Transcript, Volume 2, pages 289-290.

³⁶⁴ Transcript, Volume 2, pages 294-295.

³⁶⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1. For example, Tables T-CBC-03-2 or T-CBC-08-3 are forecast cost summary tables for the SCADA MTU life cycle replacement project and substation ancillary equipment life cycle replacement project respectively.

to construct the project. The contractor line item includes the cost of engineering work, material costs and construction costs to be completed by contractors. The engineering cost line item includes the costs of engineering work to be completed internally. Typically, if EDTI does not have the internal resources to complete the work or it does not have the internal resources with the required expertise to complete the work, only then will EDTI use contractor resources.³⁶⁶

10.5.1.4 Work coordination

534. Work is coordinated with other projects or maintenance activities where possible to minimize costs.³⁶⁷ In response to an IR from the UCA, EDTI expanded on this, stating that work is coordinated such that simultaneous equipment outages and other efficiencies can be maximized. In cases where work overlaps such that it would hinder another job, then the work will be scheduled to avoid those conflicts.³⁶⁸

535. In argument, EDTI provided examples of work which is scheduled to occur together, such as completing the projects to upgrade time synchronization devices at the same time as upgrading the local area network (LAN) architecture, because the same resources will complete both of these types of projects. EDTI also provided the work to be performed at the Rosedale substation as an example of work which is to be completed in the same substation but which will be completed at different times so one job is not hindered by the other.

10.5.1.5 EDTI's asset maintenance and replacement philosophy

536. In the application, EDTI provided insight into its asset replacement philosophy and practices, in stating:

EDTI has an aging transmission substation infrastructure. Through effective asset condition monitoring, EDTI is working to extend the life of the assets as long as economically and reliably possible. EDTI's approach is to actively monitor the condition of its assets, perform condition based maintenance, refurbish, and only replace deteriorating assets when further refurbishment is no longer feasible or economic.³⁶⁹

537. With regard to equipment that is no longer supported by the vendor or manufacturer, EDTI looks at a number of things before a decision is made to replace the asset, such as the criticality of the asset, whether there is internal or industry knowledge on how to repair the asset, the cost to repair the asset, the availability of spare parts, to what level the asset can be repaired, how long will the repair take, how frequently the asset will need repair and at what cost. This is compared to the cost, the time required and the outage required to replace the asset, among other considerations.³⁷⁰

538. Quanta's witness stated that timing for asset replacement is not agreed upon within the industry and utilities must balance the cost of replacement with the requirement to maintain a reliable system. He acknowledged that some work could be taken at a slower pace but cautioned that with this approach, there is an increasing risk to reliability and of failure. Quanta's witnesses further stated that the redundancy that is built into the system does not necessarily allow for

³⁶⁶ Exhibit 3539-X005, EDTI-AUC-2015FEB06-068 (a) and (b), PDF pages 247-248 of 513.

³⁶⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 43, PDF page 36 of 433.

³⁶⁸ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-033(e), PDF page 170 of 429.

³⁶⁹ Exhibit 0003.00.EDTI-3539, application, paragraph 1999 PDF, pages 693-694 of 900.

³⁷⁰ Transcript, Volume 2, pages 303-304.

latitude with respect to the timing of asset replacements, and that redundancy is a measure of the security of the reliability of the system only.³⁷¹

539. EDTI argued that it follows good industry practice in operating and maintaining its system and that it has adopted an asset management and replacement approach that is consistent with industry practice, is sensible and provides a reliable basis on which to determine the appropriate action to take, such as level of maintenance, determination of the need for and appropriate timing of replacement, etc.³⁷² EDTI argued that it does not simply replace assets when they reach a predetermined age, but that it actively monitors the condition of the assets, performs condition based maintenance and refurbishment on equipment, and only replaces deteriorating assets when further refurbishment is no longer technically and/or economically feasible.³⁷³

10.5.1.6 Asset health index

540. In its application EDTI refers to its asset health indices (AHI) which were provided to Quanta for the purposes of completing the SEAS study.³⁷⁴ EDTI provided the AHI for MV switchgears and the consequence of failure index (CFI) as an appendix to the application.³⁷⁵ EDTI explained that it calculates a risk index (RI) score for each switchgear by multiplying the AHI and the CFI and then taking the square root of the product. The RI is used as a comparison between switchgears and to establish a priority sequence for addressing the risks by replacing the assets. EDTI confirmed that the AHI and CFI are updated annually.³⁷⁶

541. Quanta used the basic health index method employed by EDTI to review equipment condition and, for the purposes of the SEAS study, some criteria were added to the analysis or some criteria were changed based on industry experience, which was used by Quanta to evaluate the equipment and classify the equipment as least to most concerning.³⁷⁷

542. Quanta's witness confirmed that the intent of the AHI is to ensure that replacements are done in a timely manner; not too early or too late given an asset's condition. The Quanta witnesses, in speaking to EDTI's replacement schedule, indicated that they did not find any instances where assets were replaced too early or where equipment failed and should have been replaced earlier, based on indicators that were missed or not considered prior to the failure.³⁷⁸

543. In the Project Summary SEAS report, Quanta noted that the health index methodology used by EDTI is very comprehensive and among the most complete tools of its type that Quanta has seen.³⁷⁹

10.5.1.7 Prior Commission approval of projects

544. For several ongoing life cycle replacement programs, EDTI noted that the programs have been previously approved by the Commission.³⁸⁰ The Commission asked an IR regarding what

³⁷¹ Transcript, Volume 6, pages 1202-1206.

³⁷² Exhibit 3539-X0193, EDTI argument, paragraphs 335-336, PDF page 144 of 259.

³⁷³ Exhibit 3539-X0193, EDTI argument, paragraph 298, PDF page 125 of 259.

³⁷⁴ Exhibit 0003.00.EDTI-3539, application, PDF pages 838-839 of 900.

³⁷⁵ Exhibit 0059.00.EDTI-3539, Appendix I-3.

³⁷⁶ Transcript, Volume 6, page 1162.

³⁷⁷ Exhibit 0047.00.EDTI-3539, Appendix G-8, PDF page 16 of 57.

³⁷⁸ Transcript, Volume 6, pages 1084-1085.

³⁷⁹ Exhibit 0047.00.EDTI-3539, Appendix G-8, PDF page 16 of 57.

specific approvals were given for the projects and whether any projects have been subject to disallowance. In response, EDTI provided a table which lists all ongoing life cycle replacement programs, all of which were included in EDTI's 2007-2009, 2010-2011, 2012 and 2013-2014 tariff applications and which were approved in decisions 2008-125, 2010-505, 2012-272 and 2014-269. EDTI also stated that there have not been any disallowances by the Commission related to EDTI's ongoing life cycle replacement programs in those decisions.³⁸¹

545. In argument, EDTI reiterated that the above noted ongoing life cycle replacement programs were previously approved by the Commission.³⁸²

Commission findings

546. The Commission makes no specific findings on the life cycle programs common matters in this section. Any findings will be addressed in specific project sections as applicable.

547. The Commission cautions parties against using prior Commission approval or denial of a project or project costs in a GTA as an indication that those projects/programs or related costs will be subject to the same treatment in future proceedings. While prior approval does weigh in favour of future approval for similar projects, each application's forecast project costs must be evaluated by the Commission with the evidence provided on the record before it, using the best information available.

548. The Commission finds that for any life cycle program which is not specifically addressed below, the information on the record is sufficient to approve the forecast costs as filed for the purpose of determining the revenue requirements in this application.

549. The Commission discusses certain life cycle projects below.

10.5.2 Protective relay and control system life cycle replacements and improvements (reference 9.2.2.1)

550. This program is an ongoing life cycle replacement program which consists of replacing and improving EDTI transmission protective relay and control equipment devices. This program consists of five project categories:

- replacing power transformer and bus differential relay protection schemes
- replacing substation feeder and bus over current relay protection schemes
- replacing transmission line relay protection schemes
- replacing under frequency load shedders³⁸³
- replacing and improving other substation relay schemes, such as breaker failure relay schemes³⁸⁴

³⁸⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1. For example, in business case T-CBC-04 at PDF page 57 of 433, paragraph 20, EDTI states that project subcategory 3-1: substation data gathering projects was "previously approved by the Commission."

³⁸¹ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-075(a) and (b), PDF pages 262-263 of 513.

³⁸² Exhibit 3539-X0193, EDTI argument, paragraph 419, PDF page 178 of 259.

³⁸³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 39, PDF page 10 of 433. No under frequency load shedders are forecast to be replaced in the test period. EDTI considers that project category to be complete.

³⁸⁴ Exhibit 0003.00.EDTI-3539, application, paragraphs 2002 and 2007, PDF pages 695 and 697 of 900.

551. Generally, EDTI supported the replacement of its protection systems by stating that failure of the protection equipment could result in reduced reliability, increased customer outages, increased risk of associated equipment failure and increased safety risks to EDTI personnel and the public.³⁸⁵

552. In response to an IR from the UCA, EDTI stated that the project cannot be deferred until the next GTA because it is required in order to maintain the reliability of EDTI's transmission system and ensure the safety of its staff and the public. Additionally, delaying the work does not eliminate the need for the project, it simply defers the need to deal with the life cycle replacement work which creates a greater volume of work that could eventually lead to safety, reliability and service quality issues. EDTI argued that undertaking the life cycle replacement work on such a "lumpy" basis over time is not efficient and has a large impact on required staffing and contractor levels.³⁸⁶ This response or a similar response was provided with respect to most life cycle projects and therefore will not be reiterated with respect to other life cycle projects in subsequent sections.

553. Table T-CBC-01-2 provides a breakdown of the costs associated with each project category. This table was provided in the business case³⁸⁷ and was subsequently updated for 2014 actuals. The yearly cost of the program is forecast to be \$3.73 million in 2015, \$4.0 million in 2016 and \$3.56 million in 2017.³⁸⁸ A breakdown of the components of the forecast cost (i.e., materials, engineering, labour, etc.) was provided in Table T-CBC-01-7 in the business case.³⁸⁹

554. The update provided to account for 2014 actuals showed no change in the 2015 forecast costs but the variance explanations for 2014 actuals from decision amount stated that there was a decrease of \$0.38 million due to the Woodcroft substation 72-kV breaker failure life cycle replacement project being delayed into 2015 and a decrease of \$0.10 million due to the Namao substation regulator remote control and indication project being delayed into 2015.³⁹⁰ In the hearing, EDTI clarified that these costs were already captured in the 2015 forecast at the time of the application and therefore no update was required to the forecast to account for the delay of those projects.³⁹¹ In an undertaking, EDTI provided a status update on both of those projects, stating that both are on schedule and still expected to be completed in 2015. However, the forecast for the Woodcroft project has increased by \$0.10 million to \$0.50 million due to the project being more complex than originally anticipated.³⁹²

555. EDTI evaluated three alternatives for addressing the safety and reliability issues with its substation relay protection equipment: (1) emergency repair or replacement, (2) increasing the frequency of maintenance on protective relay equipment or (3) life cycle replacement.

556. EDTI selected the third alternative, as the first and second alternatives would delay capital costs but would not resolve the safety and system reliability issues with the substation apparatus equipment.³⁹³ For the tap changer remote control project, EDTI evaluated two

³⁸⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 42, PDF page 11 of 433.

³⁸⁶ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-033(b), PDF page 168 of 429.

³⁸⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 5 of 433.

³⁸⁸ Exhibit 3539-X0089, EDTI additional information, PDF page 12 of 35.

³⁸⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-01-7, PDF page 17 of 433.

³⁹⁰ Exhibit 3539-X0084, EDTI capital variance, PDF page 1 of 35.

³⁹¹ Transcript, Volume 2, pages 427-428.

³⁹² Exhibit 3539-X0129, undertaking at Transcript, Volume 2, page 428.

³⁹³ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 19 and 21 of 433.

alternatives: do nothing or add tap changer remote controls. EDTI provided the NPV comparison of the alternatives which showed that the alternatives were similar in cost; however, the second alternative was slightly less costly and was selected by EDTI.³⁹⁴

557. The UCA did not address this program in its evidence, argument or reply.

Commission findings

558. The cost forecasts for the projects included in the protective relay and control systems life cycle replacement program are based on a bottom up approach. The Commission has reviewed the business case, including the cost components therein, the justification provided by EDTI for the necessity of the projects and the proposed replacement schedule. The Commission finds the forecast costs to be reasonable.

559. The Commission approves the forecast capital additions for the protective relay and control systems life cycle replacement projects for the purposes of determining EDTI's revenue requirement in the test period. EDTI is directed to include the forecast \$0.10 million increase in project costs on the Woodcroft substation 72-kV breaker failure life cycle replacement project, which was provided in an undertaking to the Commission, in its updated 2015 cost forecast in the compliance filing.

10.5.3 SCADA system life cycle replacement and improvement (reference 9.2.2.2)

560. This is an ongoing life cycle replacement program which consists of replacing and improving EDTI transmission SCADA and digital fault recorder (DFR) systems. This program consists of four project categories:

- SCADA master terminal unit (MTU) equipment life cycle replacements and updates to meet current AESO requirements
- remote terminal unit (RTU) life cycle replacements
- DFR life cycle replacements
- other SCADA system asset life cycle replacements (transducers, sequence of event recorders)³⁹⁵

561. Table T-CBC-02-1 provides a breakdown of the costs associated with each project category. This table was provided in the business case³⁹⁶ and was subsequently updated for 2014 actuals. The yearly cost of the program is forecast to be \$1.35 million in 2015, \$1.49 million in 2016 and \$1.47 million in 2017.³⁹⁷ A breakdown of the components of the forecast cost (i.e., materials, engineering, labour, etc.) was provided in Table T-CBC-02-5 in the business case.³⁹⁸ In response to a Commission IR, EDTI noted that there was an error in the 2016 forecast for transducers, and that while the business case shows a forecast of \$0.18 million, the correct forecast is \$0.15 million. EDTI proposed to correct this error in its refiling.³⁹⁹ In response to an

³⁹⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 21 and 23 of 433.

³⁹⁵ Exhibit 0003.00.EDTI-3539, application, paragraphs 2031 and 2034, PDF pages 706-707 of 900.

³⁹⁶ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 26 of 433.

³⁹⁷ Exhibit 3539-X0089, additional information 2014 actuals, PDF page 13 of 35.

³⁹⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-02-5, PDF page 36 of 433.

³⁹⁹ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-072 (b), PDF page 257 of 513.

undertaking, EDTI noted that the transducer replacement component of this program is a bucket project.⁴⁰⁰

562. EDTI evaluated two alternatives for addressing the issues with its SCADA MTU, RTU, DFR and transducer equipment: (1) emergency repair or replacement or (2) life cycle replacement. EDTI selected the second alternative, as the first alternative is not reasonable from a safety and system reliability standpoint. Further, while the operating costs would not increase, this alternative would result in higher costs for emergency replacement.⁴⁰¹

563. For the SCADA POD revenue metering project, EDTI evaluated two alternatives: (1) recertify existing meters or (2) replace with new meters. Under the first alternative, EDTI submitted that past experience has shown that approximately 25 per cent of the meters could not be brought back to within the required accuracy limits and therefore could not be recertified. Also, recertified meters have a shorter seal expiry date (the maximum seal period would be two years in this case compared to six years for the new meters). EDTI provided the NPV comparison of the alternatives which showed that the first alternative would be more costly than the second and therefore, the second alternative was selected by EDTI.⁴⁰²

564. The UCA did not address this program in its evidence, argument or reply.

Commission findings

565. The cost forecasts for the projects included in the SCADA system life cycle replacement program are based on a bottom up approach, with the exception of the transducer replacement project which is based on a three-year average. The Commission has reviewed the business case, including the cost components therein, the justification provided by EDTI for the necessity of the projects and the proposed replacement schedule, and finds the forecast costs to be reasonable.

566. The Commission approves the forecast capital additions for the SCADA system life cycle replacement projects for the purposes of determining EDTI's revenue requirement in the test period. In its compliance filing, EDTI is directed to include the \$0.03 million adjustment identified by EDTI in response to an IR, for the 2016 transducer forecast.⁴⁰³

10.5.4 SCADA MTU life cycle replacement project (reference 9.2.2.3)

567. This is a three-year program, from 2014 to 2016, which involves replacing EDTI's current SCADA MTU system with a new version. The existing system has two operating systems that will no longer be supported by Microsoft as of April 8, 2014 and July 14, 2015, respectively. EDTI will not have the ability to complete security patches on its SCADA MTU system, will not be compliant with the Alberta Reliability Standards (ARS) CIP-007-AB-5, which is expected to be applicable to utilities by Q3 2016, and will not be able to continue to use its security patch management methods and procedures when the software is no longer supported.⁴⁰⁴

⁴⁰⁰ Exhibit 3539-X0182.01, response to undertaking at Transcript, Volume 6, page 1177.

⁴⁰¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 38 of 433.

⁴⁰² Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 39-42 of 433.

⁴⁰³ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-072 (b), PDF page 257 of 513.

⁴⁰⁴ Exhibit 0003.00.EDTI-3539, application, paragraphs 2064 and 2066, PDF pages 714-715 of 900.

568. In the application, EDTI explained that the project commencement was delayed in order to complete the SCADA MTU replacement project in conjunction with a distribution project, outage management system/distribution management system (OMS/DMS). If the projects were completed independently, EDTI would be required to complete development and testing twice, once to replace the existing SCADA system with the new version and once to integrate the new SCADA system with the new OMS/DMS system. However, the distribution OMS/DMS project was delayed due to uncertainties with respect to the PBR mechanism.⁴⁰⁵ This delay was further discussed in the hearing and EDTI provided an undertaking to confirm that the DMS portion of the OMS/DMS project must be completed concurrently with the SCADA MTU life cycle replacement project in order to realize efficiency savings. EDTI anticipates that the DMS portion will be completed in Q4 2015 and the remainder of the project will be completed afterwards.⁴⁰⁶ In another undertaking, EDTI confirmed that the SCADA MTU life cycle replacement project is on schedule and is entering the first testing cycle.⁴⁰⁷

569. At the time of the 2013-2014 GTA, the project was forecast to cost \$3.24 million.⁴⁰⁸ The current project forecast cost is \$3.43 million, which will be capitalized over 2015 and 2016.⁴⁰⁹ The majority of the variance between the forecasts is due to AFUDC, inflation⁴¹⁰ and additional work required to complete the project that was not contemplated in the 2013-2014 forecast.⁴¹¹ EDTI justified capitalizing a portion of the project in 2015 in response to a Commission IR, noting that EDTI expects to put the new SCADA MTU system into service and commission three of the substations in 2015. The remaining substations will be tested and commissioned in 2016.⁴¹²

570. The cost estimates for this project are based on historical SCADA projects and a vendor quote. A portion of the costs of this project will be recovered from EDTI's distribution function through an asset usage fee.⁴¹³

571. EDTI evaluated three alternatives for this project: (1) maintain status quo, (2) replace the SCADA MTU system with a new system (i.e., from a new vendor) or (3) replace the SCADA MTU system with a newer version of the existing system. Alternative (1) was rejected on the basis that EDTI's SCADA MTU system will become more vulnerable to security attacks; EDTI will not be in compliance with ARS CIP-007-AB-5; nor will EDTI be able to continue with its security patch management methods and procedures currently employed. An NPV analysis was not done for alternative (1) because the potential timing and costs are uncertain. The NPV comparison of alternatives (2) and (3) show that alternative (3) is less costly. Additionally, EDTI had concerns with the second alternative that the new vendor would need to develop custom interfaces specific to EDTI's environment, which may result in more problems with the system. This, in turn, would require additional resources to troubleshoot and fix the problems, and the timing would be less desirable as this project is to be completed in conjunction with the OMS/DMS project.⁴¹⁴ A further risk of selecting alternative (2) was an increased risk of user

⁴⁰⁵ Exhibit 0003.00.EDTI-3539, application, paragraph 2074, PDF page 717 of 900.

⁴⁰⁶ Exhibit 3539-X0132, undertaking at Transcript, Volume 2, page 432.

⁴⁰⁷ Exhibit 3539-X0133, undertaking at Transcript, Volume 2, page 434.

⁴⁰⁸ Exhibit 3539-X0130, undertaking at Transcript, Volume 2, page 436.

⁴⁰⁹ Exhibit 3539-X0160, undertaking at Transcript, Volume 3, page 448.

⁴¹⁰ Transcript, Volume 3, page 446.

⁴¹¹ Exhibit 3539-X0193, EDTI argument, paragraph 412, PDF page 75 of 259.

⁴¹² Exhibit 3539-X0005, EDTI-AUC-2015FEB06-074, PDF page 260 of 513.

⁴¹³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 12, PDF page 46 of 433.

⁴¹⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 48-51 of 433.

error. EDTI provided a further NPV comparison of the alternatives in response to an IR from the UCA using the NPV revenue requirement. Alternative (3) was still less costly than alternative (2) under this comparison.⁴¹⁵

572. In its argument, EDTI noted that alternative (3) for this project was approved in Decision 2014-269.⁴¹⁶

573. The UCA did not address this program in its evidence, argument or reply.

Commission findings

574. The cost forecasts for the projects included in the SCADA MTU life cycle replacement project are based on a bottom up approach.. The Commission has reviewed the business case, including the cost components therein, the justification provided by EDTI for the necessity of the projects and the proposed replacement schedule and finds the forecast costs to be reasonable. Accordingly, the Commission approves the forecast capital additions for the SCADA MTU life cycle replacement projects for the purposes of determining EDTI's revenue requirement in the test period.

10.5.5 Communication system life cycle replacements and improvements (reference 9.2.2.4)

575. This is an ongoing life cycle replacement program which consists of replacing and improving EDTI's communication and information gathering equipment which connects EDTI's Control Centre to EDTI's transmission substations and the Alberta inter-utility communications network.⁴¹⁷ This program includes 10 individual projects in three of the four project categories listed below, during the test period. The projects are selected based on equipment information, operation performance results, equipment age analysis or compliance with ARS. The program includes the following project categories:

- teleprotection/tone/transfer trip equipment life cycle replacements
- replacing and improving communication cable circuits
- replacing and improving transmission substation information gathering and control equipment (substation automation) to enable EDTI staff to remotely interrogate online monitoring devices and microprocessor-based protective relays
- replacing and improving inter-utility and other communication systems⁴¹⁸

576. The first project category includes projects relating to the life cycle replacement of EDTI's existing teleprotection equipment. EDTI did not propose to replace any teleprotection/tone/transfer trip equipment in the test period.⁴¹⁹

577. The second category is an ongoing life cycle program to replace existing deteriorated communication cables, addition of new high speed fibre optic communication circuits associated with protective relaying and teleprotection life cycle replacement and improvement projects, and

⁴¹⁵ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-035, PDF pages 174-176 of 429.

⁴¹⁶ Exhibit 3539-X0193, EDTI argument, paragraph 410, PDF page 174 of 259.

⁴¹⁷ Exhibit 0003.00.EDTI-3539, application, paragraph 2077, PDF page 718 of 900.

⁴¹⁸ Exhibit 0003.00.EDTI-3539, application, paragraph 2079, PDF page 719 of 900.

⁴¹⁹ Exhibit 0030.00.EDTI-3539, Exhibit E-1, paragraph 10, PDF page 55 of 433.

life cycle replacement, and upgrading of EDTI's existing microwave communication system.⁴²⁰ EDTI proposed to add new fibre optic communication cable links between Victoria and Woodcroft substations and between Lambton and Hardisty substations. EDTI stated that the existing fibre optic cable has reached its capacity limit and has been relocated and reconfigured several times, which has reduced the overall reliability of the cable.⁴²¹ In 2015 and 2016, EDTI also proposed to relocate two fibre optic cables and three copper cables which ran along the Walterdale Bridge. The City of Edmonton will pay all project costs for the relocation project so there will be no addition to rate base associated with this project.⁴²²

578. The substation automation category includes two subcategories: substation data gathering projects, and substation LAN architecture and time synchronization projects. The substation data gathering program is a multiyear program which includes projects at various substations relating to the addition of communication circuits to substation intelligent electronic devices (IEDs). Additionally, the projects are anticipated to reduce EDTI's overall SCADA MTU system computing resource and communication requirements and improve field crew safety.⁴²³

579. The substation data gathering network will be fully compliant with IEC Standard 61850 which, while not required in Alberta, will allow better change management, highly efficient object-oriented design, reduced substation wiring, zero-failover time redundancy, faster inter-IED communications, advanced testing capabilities, etc.⁴²⁴ EDTI is proposing to replace the substation data gathering systems at Summerside and Clover Bar POD substations in 2015 and 2016 respectively. Substation data gathering projects were completed at these substations in 2008 and 2010, but since then, EDTI has experienced failures on both installations so each location requires a major replacement to regain full operation.⁴²⁵ In response to a Commission IR, EDTI provided a table which listed all failures that occurred at Summerside and Clover Bar POD substations and the reasons for failures.⁴²⁶

580. The substation LAN architecture and time synchronization projects subcategory consists of adding router assets and time synchronization devices,⁴²⁷ and making the following adjustments to EDTI's LAN architecture associated with its newer substation automation installations:

- installation of access point protection for site security
- installation of layer 3 routing capability
- setup of virtual private networks

581. The upgrading of time synchronization devices will be completed at the same time as upgrading substation LAN architecture, because the same resources will complete both of these

⁴²⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 11, PDF pages 55-56 of 433.

⁴²¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 12-15, PDF page 56 of 433.

⁴²² Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 16, PDF pages 56-57 of 433.

⁴²³ It will improve field crew safety by eliminating the need for staff to stand in front of energized switchgears in order to obtain equipment performance information.

⁴²⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 59 of 433.

⁴²⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 26, PDF page 59 of 433.

⁴²⁶ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-076, PDF pages 265-266 of 513.

⁴²⁷ Time synchronization work was included under the SCADA system life cycle replacement and improvement program in the previous application. In response to a Commission IR (EDTI-AUC-2015FEB06-077), EDTI stated that the work was re-categorized to realize efficiencies by doing the work at the same time as the substation LAN architecture upgrades.

types of projects. The time synchronization work (installing a time synchronization device with a higher IED output rating) is required as the existing devices are not rated for the number of IEDs connected to them, which causes the internal clocks to drift. Time synchronization work ensures that the internal clocks of IEDs are synchronized to the universal standard time signal, without which inaccurate event information could result. EDTI intends to carry out LAN architecture and time synchronization projects at Victoria Terminal and Kennedale substation in 2015, Lambton and Petrolia substations in 2016, and Dome and Woodcroft substations in 2017.⁴²⁸

582. The final category of projects includes inter-utility telecommunication upgrades and SONET system life cycle replacement and improvement projects, at a total forecast cost of less than \$0.25 million. EDTI does not propose any telecommunication upgrades in the test period. EDTI is forecasting to complete 10 SONET card firmware upgrades and to replace 10 SONET cards. This forecast is based on the number of projected relay projects expected to be completed in the test period.^{429 430} This project subcategory also includes replacement of SONET system equipment that has failed unexpectedly, the cost of which is calculated based on a three-year historical average.⁴³¹ This subcategory was confirmed to be a bucket project, in response to an undertaking.⁴³² Generally, whenever new equipment is installed on the SONET system, EDTI must complete SONET card replacements and improvements in order for the SONET system to function properly. The SONET system provides SCADA monitoring and control, inter-substation direct transfer trip and inter-substation relay-to-relay communication as well as providing substation connection to EDTI's telephone system so that operation and engineering staff can access field crews in the substation.⁴³³

583. In response to an IR from the UCA regarding SCADA-related projects such as this program, the SCADA MTU replacement project and the SCADA network life cycle replacement program, EDTI confirmed its approach is to replace or upgrade portions of the SCADA systems as required and that a global scale upgrade of the SCADA system would be very costly compared to completing sub-projects as they are required.⁴³⁴

584. Table T-CBC-04-1 provides a breakdown of the costs associated with each project category. This table was provided in the business case⁴³⁵ and was subsequently updated for 2014 actuals. The yearly cost of the program is forecast to be \$2.47 million in 2015, \$0.90 million in 2016 and \$1.57 million in 2017.⁴³⁶ The 2015 capital addition forecast was revised from \$1.60 million as a result of delays to the completion of the Petrolia to Dome fibre optic project, which EDTI expected to have completed by the end of 2014 but which is now forecast to be completed and placed into service in 2015. EDTI confirmed that no impacts to 2016 and 2017

⁴²⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 33-37, PDF pages 60-62 of 433.

⁴²⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 63 of 433.

⁴³⁰ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-077 (b): The adaptive type protections referred to are part of EDTI's feeder overcurrent protection life cycle replacement projects which are discussed in Section 10.5.2 of this decision.

⁴³¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 46, PDF page 64 of 433.

⁴³² Exhibit 3539-X0182.01, undertaking at Transcript, Volume 6, page 1177.

⁴³³ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 63-64 of 433.

⁴³⁴ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-045 (c), PDF page 324 of 429.

⁴³⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 55 of 433.

⁴³⁶ Exhibit 3539-X0089, EDTI additional information, Table T-CBC-04-1 Updated, PDF page 13 of 35.

forecasts are anticipated.⁴³⁷ A breakdown of the components of the forecast cost (i.e., materials, engineering, labour, etc.) was provided in Table T-CBC-04-5 in the business case.⁴³⁸

585. EDTI provided a PIR for 2013 actual expenditures and rate base additions in Appendix E-2 to the application which provides variance explanations between 2013 decision and actual capital additions. The variance explanation between 2014 decision and actuals was provided in Exhibit 3539-X0084. The variance between 2014 decision and actuals was due to delays to completion of the Petrolia to Dome fibre optic project from 2014 to 2015, the Kennedale fibre optic project not being completed in 2014 and a decrease in the costs for the Meadowlark to Petrolia fibre optic cabling project due to contractor bids being lower than estimated and a reduction in dewatering and disposal costs as a result of new environmental procedures.⁴³⁹ An EDTI witness stated that the savings in costs for contractors pulling the fibre optic cable were not accounted for in the forecasts for the test years because 2014 actuals were not available at the time of the forecast. However, the cost savings for dewatering were likely accounted for in the forecasts for the test years because the approval process for dewatering with the City of Edmonton began in 2014 and would have been carried forward.⁴⁴⁰ In its argument, EDTI argued that the forecasts for the test years should not be decreased to account for past savings in contractor costs because the forecast approach for the test years is a bottom up approach which does not use the same basis for the estimate as was used in 2014.⁴⁴¹

586. Three separate alternatives analyses were provided in the application and the business case:

- alternatives analysis for the Victoria to Woodcroft and Lambton to Hardisty fibre optic cable projects
- alternatives analysis for the two substation data gathering replacement projects at Clover Bar POD and Summerside substations
- alternatives analysis for other communication system life cycle replacements and improvements⁴⁴²

587. EDTI evaluated two alternatives for the fibre optic cable projects: (1) replace the existing fibre optic cable with new fibre optic cables or (2) add new fibre optic cables between the substations. The NPV analysis shows that the second alternative is somewhat less costly than the first. EDTI selected alternative (2) as alternative (1) has higher costs due to the inclusion of decommissioning and removing old cables in addition to the installation of new cables.⁴⁴³

588. EDTI evaluated two alternatives for the data gathering projects: (1) maintain the status quo or (2) replace the substation automation at both locations (Clover Bar POD and Summerside). The NPV analysis shows that the second alternative is somewhat less costly than the first. Under the first alternative, EDTI would still replace the failed redundant control units and EDTI forecast continued repairs at their current pace. Under the second alternative, EDTI would no longer have operating costs associated with two different substation automation

⁴³⁷ Exhibit 3539-X0089, EDTI additional information, PDF page 14 of 35.

⁴³⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-04-5, PDF page 69 of 433.

⁴³⁹ Exhibit 3539-X0124, undertaking at Transcript, Volume 1, page 120.

⁴⁴⁰ Transcript, Volume 5, pages 865-867.

⁴⁴¹ Exhibit 3539-X0193, EDTI argument, PDF pages 177-178 of 259.

⁴⁴² Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 61, PDF page 70 of 433.

⁴⁴³ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 70-72 of 433.

platforms. EDTI selected the second alternative on the basis that it was less costly than the first.⁴⁴⁴

589. EDTI evaluated two alternatives for all other communication life cycle replacements and improvements: (1) emergency repair or replacement only or (2) the life cycle replacement program. EDTI did not conduct an NPV analysis for these alternatives. EDTI rejected the first alternative on the basis that the reliable and dependable functionality of EDTI's communication and information gathering equipment is critical to the overall operation of EDTI's transmission system, and operating equipment to failure is unacceptable given the operating and safety risks. Additionally, EDTI noted that replacing equipment on an emergency basis is more costly than if the equipment is replaced on a planned, life cycle replacement basis. EDTI stated that alternative (2) is the only reasonable alternative for this work.⁴⁴⁵

590. The UCA did not address this program in its evidence, argument or reply.

Commission findings

591. The cost forecasts for the projects included in the communication system life cycle replacements and improvements program are based on a bottom up approach with the exception of SONET replacements which are forecast using a three-year average. The Commission has reviewed the business case, and the cost components therein, and the justification provided by EDTI for the necessity of the projects and the proposed replacement schedule, and finds the forecast costs to be reasonable.

592. The Commission approves the forecast capital additions for the communication system life cycle replacement and improvement projects for the purposes of determining EDTI's revenue requirement in the test period.

10.5.6 Substation building life cycle replacements (reference 9.2.2.5)

593. This is an ongoing life cycle program which consists of replacements and improvements related to EDTI transmission substation buildings. This program includes two project categories: substation building roof life cycle replacements and substation building life cycle replacements and improvements. Within the building life cycle replacements and improvements are the following project subcategories:

- retrofitting substation buildings to meet current Occupational Health and Safety (OHS 2009) and Alberta Building Code (ABC) and fire code requirements
- replacing building system assets that have failed beyond repair and upgrading assets as required
- substation asbestos abatement⁴⁴⁶

594. The majority of EDTI transmission substation buildings have flat, tar or gravel roofing which typically has a life expectancy of 25 years. The reliable operation of substation equipment housed within the substation building requires, in part, a building roof which is impervious to water infiltration. EDTI contracts a qualified Alberta roofing inspector and engineering company specializing in roofing work to provide independent advice on the state of its substation building

⁴⁴⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 72-74 of 433.

⁴⁴⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 74-75 of 433.

⁴⁴⁶ Exhibit 0003.00.EDTI-3539, application, PDF pages 730-731 of 900.

roofs. Inspections are performed every two years. As part of the substation building roof life cycle replacement projects, EDTI will install roof guards-railings in order to comply with the ABC 2006 and other codes and standards, and in order to mitigate the risk of accidental falls.

595. EDTI is proposing to replace the roofs at the following substations on a like-for-like basis:⁴⁴⁷ East Industrial in 2015, Woodcroft in 2016 and Dome in 2017. The roofs EDTI proposes to replace are between 19 and 23 years old. The new guardrails at these substation buildings will be included in the roof replacement work.⁴⁴⁸ The roofing inspections which EDTI relied on when selecting the roofs to replace and the timing of the replacement were completed in 2006, 2007 and 2008. The reports were provided as attachments to EDTI-UCA-2015FEB06-037.⁴⁴⁹ The 2008 report shows a remaining life of 13 years for the Dome substation roof, four to six years for the East Industrial substation roof and six to eight years for the Woodcroft substation roof.⁴⁵⁰

596. EDTI considered two alternatives to address the aging and worn roofs at the selected substations: (1) maintain the status quo, which was rejected because it could risk failure of the roof and therefore damage to the substation equipment, or (2) replace the roofs. Outside of replacing the entire substation building, EDTI indicated it was not aware of any other alternatives and the alternative of replacing the entire substation is significantly more costly and would require outages.⁴⁵¹

597. The multi-year building life cycle replacements and improvements project began in 2002 to bring substation buildings up to current building and fire code requirements. This program also addresses building deficiency and improvement issues resulting from the age and condition of a building's infrastructure, inadequate fire detection systems, inadequate emergency and exit lighting systems, and the increased need for controlled temperature environments required by new relaying equipment. Substation buildings which are selected for life cycle replacements and improvements are identified through periodic inspections performed by EDTI employees or through periodic audits of the buildings by external engineering/architectural consultants. EDTI included the costs of audits for three substation buildings in the test period.

598. EDTI proposed completing the following projects in 2015: asbestos abatement, Castledowns substation water ingress mitigation (Phase 1), substation building systems emergency replacement, Woodcroft substation HVAC upgrade, Bellamy substation building sewage replacement and Bellamy substation building improvement projects. EDTI is proposing to complete the following projects in 2016: asbestos abatement, Castledowns substation water ingress mitigation (Phase 2), Hardisty substation HVAC upgrades, substation building systems emergency replacement and Garneau substation building improvement (Phase 1) projects. EDTI proposed to complete the following projects in 2017: asbestos abatement, Jasper substation water ingress mitigation, substation building systems emergency replacement and Garneau substation building improvement (Phase 2) projects. These projects will be explored separately in the subsections below.

⁴⁴⁷ Transcript, Volume 3, pages 454-455.

⁴⁴⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 6-10, PDF pages 79-80 of 433.

⁴⁴⁹ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-037(d) and attachments 1-3, PDF pages 182 and 189-290 of 429.

⁴⁵⁰ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-037, Attachment 3, PDF pages 251-290 of 429.

⁴⁵¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 50-52, PDF page 90 of 433.

599. Table T-CBC-05-1 provides a breakdown of the costs associated with each project category (substation building roof life cycle replacements and substation building life cycle replacements and improvements):

Table 36. Rate base additions for substation building life cycle replacements

	A 2012 A	B 2013 F	C 2013 A	D 2014 F	E 2014 UF	F 2015 F	G 2016 F	H 2017 F
	(\$ million)							
1 Roof replacement	-	-	-	-	-	0.14	0.12	0.20
2 Building improvements	0.72	0.73	0.73	0.63	0.57	1.18	0.99	0.56
3 Total	0.72	0.73	0.73	0.63	0.57	1.32	1.11	0.76

Source: Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 79 of 433.

600. The yearly cost of the program is forecast to be \$1.32 million in 2015, \$1.11 million in 2016 and \$0.76 million in 2017.⁴⁵² A breakdown of the components of the forecast cost (e.g., materials, engineering, labour, etc.) was provided in Table T-CBC-05-2.⁴⁵³ EDTI indicated that no impact to the forecast costs is anticipated as a result of the updated 2014 actual information.⁴⁵⁴

601. The UCA did not address this program in its evidence, argument or reply.

10.5.6.1 Asbestos abatement

602. The asbestos abatement project involves removing material containing asbestos from EDTI's transmission substation buildings.⁴⁵⁵ Asbestos removal is required by the OHS 2009 in conditions where there is a potential for asbestos fibres to be released or in buildings that are being altered, renovated or demolished and have the potential to release asbestos fibres.⁴⁵⁶ During the hearing, EDTI's witness clarified that asbestos abatement is required in locations where people will be working in the vicinity of paper-insulated lead-case cables (PILC). These cables have an asbestos wrapping and this project is to remove the asbestos and cover the cable with a polyvinyl chloride (PVC) wrapping before people working on other projects in that location will be present.⁴⁵⁷ EDTI proposed that, because this project is required to be compliant with OHS 2009, EDTI's only option is abatement. Asbestos abatement work will be undertaken at the Jasper, Castledowns, Dome, Petrolia, Lambton and Namao substations over the test period.⁴⁵⁸

603. Table 9.2.3.6-1 in the application references the SEAS report as justification for asbestos abatement projects but the referenced pages of the report pertain to asbestos abatement in Hardisty and Strathcona. However, the reference to Hardisty states: "In some older EPCOR substations such as Hardisty there is an existing asbestos hazard in the facility. EPCOR has initiated a substation asbestos abatement program for buses 2 and 3 at Hardisty. Quanta Technology endorsed this program."⁴⁵⁹

⁴⁵² Exhibit 3539-X0089, EDTI additional information, Table T-CBC-05-1, PDF page 14 of 35.

⁴⁵³ Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-04-5, PDF page 69 of 433.

⁴⁵⁴ Exhibit 3539-X0089, EDTI additional information, PDF page 14 of 35.

⁴⁵⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 82 of 433.

⁴⁵⁶ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-037(e)(ii), PDF page 183 of 429.

⁴⁵⁷ Transcript, Volume 3, pages 462-463.

⁴⁵⁸ Exhibit 3539-X0157, undertaking at Transcript, Volume 3, page 461.

⁴⁵⁹ Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 21 of 91.

10.5.6.2 Water ingress mitigation projects

604. Water ingress mitigation projects are proposed at Castledowns and Jasper substations in the test period. The work at Castledowns will be completed in two phases and the work at Jasper will be completed in one phase. Both projects include work to mitigate cracks which have developed in the basement walls and floor, and to reduce the water which enters the basements and the consequent basement humidity. This humidity can result in equipment corroding and moisture accumulating in electrical panels.⁴⁶⁰

605. EDTI did not provide an NPV analysis for the water ingress mitigation projects. EDTI rejected maintaining the status quo as this would only defer the need for the project and the risk of costly damage to substation equipment is not acceptable. EDTI noted that one alternative would be to lift the building and foundation above the ground water level but this would be approximately four times more expensive than the proposed projects. EDTI does not anticipate any change in operating expenses as a result of this project.⁴⁶¹

606. Table 9.2.3.6-1 in the application references the SEAS report as justification for flooding mitigation projects but the referenced pages of the report pertain to flooding experienced at East Industrial and Petrolia substations. The report made note of a substation building flooding mitigation plan prepared by EDTI which Quanta proposed will address water ingress problems.⁴⁶²

10.5.6.3 Building improvement projects

607. These projects are proposed to bring the substation buildings up to current ABC, fire codes and OHS. EDTI confirmed that it is technically not required to proceed with these projects as the buildings are grandfathered under previous ABC, fire codes and OHS requirements, but submitted that these projects are nonetheless important from a safety and reliability perspective. EDTI also noted that it does not have a policy to upgrade all of its buildings to current standards but considers the need for projects on a case-by-case basis.⁴⁶³

608. Substation buildings selected for life cycle replacement and improvement projects are identified through inspections and building and fire code audits.⁴⁶⁴ There is one project planned in 2015 at Bellamy and one project at Garneau which will be completed in two stages over 2016 and 2017. The work to be done in Bellamy includes installation of a remotely monitored fire detection and alarm system, installation of emergency and exit lighting, replacement of heaters and light fixtures, substation interior painting, replacement of the ventilation system, and exterior wall sealant and concrete structure cast repair. The work to be done at Garneau includes replacing the deteriorated exterior insulation and stucco stippled finish which has been damaged by water and mold, repair of the basement concrete cast structure, installation of weather stripping, replacement of the emergency generator room exterior metal door and frame, installation of a remotely monitored fire detection and alarm system, installation of emergency and exit lighting, installation of interior staircase and roof guard rails, installation of the battery bank ventilation system, replacing wall heaters, substation interior painting and replacing the HVAC roof top unit.⁴⁶⁵ Table 9.2.3.6-1 in the application references the SEAS report as

⁴⁶⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 82-83 of 433.

⁴⁶¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 55-57, PDF page 91 of 433.

⁴⁶² Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 18 of 91.

⁴⁶³ Exhibit 3539-X0193, EDTI final argument, paragraph 434, PDF page 181 of 259.

⁴⁶⁴ Exhibit 3539-X0193, EDTI final argument, paragraphs 430-431, PDF pages 180-181 of 259.

⁴⁶⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 83-84 of 433.

justification for HVAC system replacements but the referenced page of the report pertains to an HVAC system unit replacement at Jasper substation which was planned to be completed in 2013.⁴⁶⁶

10.5.6.4 Substation building HVAC upgrades

609. EDTI proposed two HVAC upgrade projects in the test period, one at Woodcroft which is anticipated to be complete in 2015 and one at Hardisty substation which is anticipated to be complete in 2016. The projects are required because the current HVAC systems do not provide cold air to the relay room or basement, and the addition of equipment over time has increased the temperature in those rooms beyond that recommended by the manufacturer for relay panels. The proposed project would also bring the building up to the current building code requirements.⁴⁶⁷

610. EDTI completed a preliminary study related to the Kennedale relay room addition project. The study showed that one HVAC system is required for approximately every 10 relay and SCADA panels. EDTI submitted that the results from the study at Kennedale apply equally to the relay rooms at Woodcroft and Hardisty which are similar in size and have the same installed relay and SCADA panels. Between 2010 and 2014, EDTI installed two relay panels in the relay room at Woodcroft which brings the total number of relay and SCADA panels to seven. In that same period, EDTI installed two new relay panels in the relay room at Hardisty which brings the total number of relay and SCADA panels to nine.

611. Woodcroft and Hardisty do not have HVAC systems but are cooled by fans. EDTI does not monitor the temperature in substation relay rooms but provided anecdotal evidence that staff have noticed that the rooms are at a higher temperature than the rest of the building.

612. EDTI stated that deferring the project is not possible as it is required to be compliant with the ABC and because it could result in overheating or damage to equipment which could lead to outages.⁴⁶⁸

10.5.6.5 Bellamy substation sewage line replacement

613. This project is required because the sewage line connecting the substation building to the main sewer line is collapsing and cracks in the wall of this line have been identified. The scope of work for this project includes installing a new drain line from the substation building to the main sewer line, plugging the existing sewer line downstream of the main sewage line and replacing the existing vent with a new 48 inch manhole.⁴⁶⁹ EDTI considered three alternatives for this project but rejected maintaining the status quo as unreasonable and rejected the alternative of repairing the existing line as it would cost more than the proposed project while the operating costs of this alternative compared to replacement would be the same.⁴⁷⁰ This project was originally to be completed in 2014⁴⁷¹ but was delayed and was confirmed to have been completed in May 2015.⁴⁷²

⁴⁶⁶ Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 18 of 91.

⁴⁶⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 85-86 of 433.

⁴⁶⁸ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-037(j) and (k), PDF pages 186-188 of 429.

⁴⁶⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 42-43, PDF page 88 of 433.

⁴⁷⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 64-65, PDF page 93 of 433.

⁴⁷¹ Transcript, Volume 3, page 459.

⁴⁷² Exhibit 3539-X0144, undertaking at Transcript, Volume 3, page 352.

10.5.6.6 Substation building systems emergency replacement

614. This project subcategory includes emergency replacement (meaning replacement of assets that have failed or are facing imminent failure) of transmission substation building systems such as doors, windows, hoists, lighting fixtures, plumbing fixtures, heaters, air conditioning, fans, and fire and security system fixtures.⁴⁷³ These replacements typically consist of a like-for-like replacement.⁴⁷⁴ The total forecast costs for this subcategory are \$0.14 million over the test period.⁴⁷⁵ Costs for this project subcategory are forecast based on a three-year average. EDTI clarified that this work is not part of O&M because EDTI's policy is to account for an asset replacement as a capital asset if the asset is identified in the property unit catalogue. A repair of the same item would be an O&M cost.⁴⁷⁶

615. EDTI considered three alternatives for this project: (1) not replace the assets, (2) replace the assets before they fail, or (3) replace on an emergency basis. EDTI rejected the first alternative despite it being the lowest cost alternative in the short term because the assets are required for the proper functioning of EDTI's substations. EDTI stated that alternative two is unnecessary as the assets can be replaced in a short period of time and failure of the assets does not compromise safety or reliability of EDTI's transmission system if the assets are replaced shortly after failure.⁴⁷⁷

Commission findings

616. The costs forecast for the projects included in the substation building life cycle replacements are based on a bottom up approach, subject to a few exceptions where the forecast is based on a three-year average. The Commission has reviewed the business case, including the cost components therein, the justification provided by EDTI for the necessity of the projects and the proposed replacement schedule and finds the forecast costs to be reasonable.

617. The Commission approves the forecast capital additions for the substation building life cycle replacement projects for the purposes of determining EDTI's revenue requirement in the test period.

10.5.7 Substation ancillary system life cycle (reference 9.2.2.9)

618. EDTI indicated that this ongoing life cycle replacement and improvement program consists of various projects aimed at maintaining the operational integrity of EDTI's existing transmission substations.⁴⁷⁸ This programs consists of a number of project subcategories, specifically:

- replacing substation switchyard grounding systems
- replacing substation battery and battery charger systems
- replacing substation revenue metering equipment⁴⁷⁹
- replacing PILC cables and terminations

⁴⁷³ Exhibit 0003.00.EDTI-3539, application, paragraph 2125, PDF page 733 of 900.

⁴⁷⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 62, PDF page 92 of 433.

⁴⁷⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 40, PDF page 88 of 433.

⁴⁷⁶ Transcript, Volume 3, page 464.

⁴⁷⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 63, PDF page 92 of 433.

⁴⁷⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, T-CBC-08, paragraphs 1-2, PDF page 131 of 433.

⁴⁷⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 135 of 433: EDTI has not identified any revenue meters that need to be replaced in the test period.

- completing other substation safety, environment and regulation and code equipment life cycle replacements and improvements
- upgrading substation AC and direct current (DC) service panels
- adding redundant AC and DC systems
- replacing emergency generators
- upgrading substation switchyard lighting systems

619. In the test period, EDTI proposed to include the following new ancillary system projects to this life cycle replacement program: upgrading transformer oil containment pits, substation noise mitigation, replacing substation fence ground bonding, and replacing and upgrading substation cable tray and cable ducts. Each project is selected based on an analysis of data collected from inspection and test results, equipment condition assessment and operational performance results.⁴⁸⁰ EDTI forecast capital additions associated with this program in the amount of \$1.65 million in 2015, \$1.30 million in 2016 and \$1.63 million in 2017.⁴⁸¹

Table 37. Rate base additions for substation ancillary equipment life cycle replacements

	A 2013 D	B 2013 A	C 2014 D	D 2014 UF	E 2015 F	F 2016 F	G 2017 F
	(\$ million)						
1 Replacing substation switchyard grounding systems	0.08	0.11	0.09	0.11	0.23	0.14	0.11
2 Replacing substation battery and battery charger systems	0.09	0.09	0.09	0.08	0.04	0.03	0.03
3 Replacing substation revenue metering equipment	-	-	-	-	-	-	-
4 Replacing PILC cables and termination	0.22	0.18	0.22	0.19	0.19	0.20	0.21
5 Other substation safety, environmental, and regulation and code	0.71	0.83	0.08	0.04	0.04	0.04	0.05
6 Upgrading substation of AC and DC panels	0.12	0.09	0.10	0.10	0.06	0.04	0.08
7 Addition of redundant AC and DC systems	0.45	0.42	0.30	0.30	0.10	0.11	0.11
8 Replacement of emergency generator	0.06	0.04	-	0.03	0.19	-	-
9 Upgrading substation switchyard lighting	0.08	0.07	0.10	0.10	-	-	-
10 Replacement of cable tray foundation at Genesee substation	-	-	-	-	0.08	-	-
11 Upgrade of transformer oil containment pits	-	-	-	-	0.04	0.05	-
12 Substation noise mitigation	-	-	-	-	-	-	0.57
13 Replacement substation fence grounding bonding	-	-	-	-	0.05	0.05	0.05
14 Replacing and upgrading substation cable trays and cable ducts	-	-	-	-	0.63	0.63	0.41
15 Total substation ancillary equipment life cycle replacements	1.80	1.83	0.97	0.94	1.65	1.30	1.63

Source: Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-08-1 PDF page 132 of 433.

Commission findings

620. With the exception of those projects within the substation ancillary system life cycle replacement and improvements program, which are addressed in the five subsections which follow, the Commission has reviewed the business case, including the cost components therein, the justification provided by EDTI for the necessity of the projects and the proposed replacement schedule and finds the forecast costs to be reasonable.

621. The Commission approves the forecast capital additions for the following substation ancillary system life cycle replacement and improvement projects for the purposes of determining EDTI's revenue requirement during the test period: replace substation switchyard grounding systems, replace substation battery and battery charger systems, replace PILC cables and termination, upgrade substation AC and DC panels, replace emergency generator, upgrade

⁴⁸⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 3-5 PDF pages 131-132 of 433.

⁴⁸¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-08-1 PDF page 132 of 433.

substation switchyard lighting, replace cable tray foundation at Genesee substation, and upgrade transformer oil containment pits.

10.5.7.1 Other substation safety, environmental, regulation and code equipment life cycle replacement and improvements

622. This category of projects includes any “one off” transmission substation improvement projects which are required to meet safety, environmental or regulatory codes and standards. The forecast cost for the test years is \$0.04 million in 2015, \$0.04 million in 2016 and \$0.05 million in 2017. However, EDTI cautioned that the number and scope of projects varies from year to year and therefore, the forecast expenditures and rate base additions can vary significantly from year to year. The scope of the projects is determined based on the results of inspections that EDTI carries out for its substation insurance, security compliance and due diligence.⁴⁸²

Commission findings

623. This project category consists of small projects which may be required to bring substation ancillary systems up to safety, environmental or regulatory codes or standards. The business case and application provided no further information regarding what those codes or standards may be, what projects are included in this subcategory, why the projects in this category could not be included in another category of life cycle programs, or why the work required to bring substation ancillary systems up to code is not considered an O&M cost. The Commission acknowledges that the forecast costs are not significant. However, given that the business case for this program provides inadequate justification for the project requirements or costs, the Commission denies the costs in this category for the test years on a forecast basis for the purposes of determining EDTI’s revenue requirement during the test period. The Commission directs EDTI to remove the forecast costs associated with this project from its revenue requirement in its compliance filing. Any actual costs incurred in the test period for these projects may be capitalized in EDTI’s next tariff application if the Commission is satisfied the expenditures were prudent.

10.5.7.2 Addition of redundant AC and DC systems at critical EDTI substations

624. EDTI proposed adding a second station battery and charger at critical 240-kV substations which have single source, single point failure DC systems that supply the substation devices. EDTI also proposed to add a second station service supply at critical 240-kV substations which have single source, single point of failure AC systems that supply substation devices.⁴⁸³ The purpose of this project is to achieve redundancy and increase reliability of the substation.⁴⁸⁴ The need for DC system redundancy is outlined in AESO Rule 502.3. The rule came into effect on December 31, 2012 and states:

13(1) The direct current supply for each of the two (2) protection systems for a facility must be protected such that a direct current fault within one (1) of the protection systems is isolated and will not affect the operation of the other protection system.

(2) A protection system must be such that it may be isolated from its direct current supply without affecting the operation of any other protection system.⁴⁸⁵

⁴⁸² Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 30-31, PDF pages 137-138 of 433.

⁴⁸³ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 140 of 433: EDTI is not proposing to install redundant AC systems in the test period as all its 240-kV substation currently have redundant AC systems.

⁴⁸⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 36, PDF page 139 of 433.

⁴⁸⁵ AESO Rule 502.3, Interconnected Electric System Protection Requirements, December 31, 2012, Section 13.

625. AESO Rule 502.3 succeeds the Alberta Interconnected Electric System (AIES) Protection Standard which came into effect as of December 1, 2004.⁴⁸⁶ The AIES Protection Standard also contained provisions for redundancy:

M2. Where redundancy in the protection systems due to single protection system component failures is necessary to meet the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I, the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations.⁴⁸⁷

626. EDTI proposed the additions described above to occur at one selected location per year. The location is selected taking into consideration the condition of the AC and DC systems, other proposed AC and DC system upgrade projects, and the criticality and system risk associated with the substation.⁴⁸⁸ In the test period, the substations selected are Castle Downs in 2015, Jasper in 2016 and Bellamy in 2017. The forecast costs for the test period are \$0.10 million in 2015, \$0.11 million in 2016 and \$0.11 million in 2017.⁴⁸⁹

627. In Table 9.2.3.6-1 in the application, EDTI provides references to the SEAS Substation report which include recommendations from Quanta for redundant AC and DC systems.⁴⁹⁰ The report states: “Based on AIES protection standard an appropriate level of protection and control system redundancy is required for 240-kV substations, EPCOR is adding a redundant DC system in 2013. This project is necessary to meet the applicable standard and Quanta confirms the action as appropriate.” This quote is in reference to the Lambton substation.⁴⁹¹ Additional references to the SEAS report refer to the need for redundant AC and DC systems at Petrolia substation⁴⁹² (which was completed in 2014⁴⁹³). The Commission requested additional information on EDTI’s references to the SEAS report and EDTI’s response indicated that in the SEAS report, Quanta found EDTI’s proposed project to add redundant DC systems at its 240-kV substation to be necessary to meet the applicable AIES Protection Standard.⁴⁹⁴

628. The project is also required for reliability because, should a battery bank fail and the DC load exceed the output of the battery bank charger, an outage of the DC supply would occur, which could result in the loss of protective relays, the SCADA systems and the control circuits of the circuit breakers in the substation. This could, in turn, result in protective relays tripping a breaker or other equipment.

Commission findings

629. The Commission is aware of the AESO rules which require this redundancy and finds that the need for the project is justified. The Commission has reviewed the record and finds that EDTI has provided sufficient information to determine that the criteria which EDTI evaluates

⁴⁸⁶ AESO Rule 502.3, Interconnected Electric System Protection Requirements, December 31, 2012, Section 5.

⁴⁸⁷ AESO Alberta Interconnected Electric System Protection Standard, Rev. 0, December 1, 2004, Appendix 1, Section M2.

⁴⁸⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 39, PDF page 139 of 433.

⁴⁸⁹ Exhibit 3539-X0089, additional information, Table T-CBC-08-1, PDF page 17 of 35.

⁴⁹⁰ Exhibit 0003.00.EDTI-3539, application, Table 9.2.3.6-1, PDF page 840 of 900.

⁴⁹¹ Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 27 of 91.

⁴⁹² Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 30 of 91.

⁴⁹³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 40, PDF pages 139-140 of 433.

⁴⁹⁴ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-045(a), PDF page 157 of 513.

when prioritising substations for the addition of redundant DC systems is reasonable. The Commission also notes that the forecast costs for each year of the test period are less than past additions with respect to this project⁴⁹⁵ and that, coupled with the requirement for the systems, is sufficient for the Commission to consider the forecast costs to be reasonable. Accordingly, the Commission approves the forecast capital additions for the substation ancillary system life cycle replacement addition of redundant DC systems at critical 240-kV substations project for the purposes of determining EDTI's revenue requirement in the test period.

10.5.7.3 Noise mitigation

630. For this “one off” project, EDTI proposed to install a noise cancelling wall and a substation transformer noise attenuation wall at its Meadowlark substation in 2017 at a total cost of \$0.57 million.⁴⁹⁶ EDTI explained that this substation was constructed and in operation before October 17, 1988 and, as such, is a “deferred facility” as defined in Section 2.2 of AUC [Rule 012: Noise Control](#). Pursuant to Section 2.2 of Rule 012, a deferred facility is not required to demonstrate compliance with the permissible sound levels (PSL) established under Section 2.1 of the rule in the absence of a noise complaint.⁴⁹⁷ On this basis, EDTI is currently compliant with Rule 012 at its Meadowlark substation.⁴⁹⁸

631. However, Section 2.2(4) of Rule 012 provides:

Effective October 17, 2018, the Commission will eliminate the deferred status for facilities built and in operation prior to 1988. Any application received after this date for modification of a deferred facility must demonstrate compliance with the permissible sound level as determined in Section 2 of this rule.

632. EDTI stated that the effect of Section 2.2(4) was that its Meadowlark substation would be required to demonstrate compliance with the permissible sound levels under Section 2.1 of Rule 012 effective October 17, 2018.

633. EDTI considered two alternatives to comply with the PSL requirements of Rule 012: to install a noise cancelling wall and a substation transformer noise attenuation wall, or to construct a building around the transformers. The second alternative was forecast to cost approximately six times more than a wall and the operating costs would be approximately equal under both alternatives. EDTI stated that the status quo was not considered an alternative as this project is required to comply with the PSL requirements of Rule 012.⁴⁹⁹

634. In response to Commission IRs, EDTI filed a noise impact assessment (NIA) prepared by Acoustical Consultants Inc. dated October 2, 2012, in relation to a “barrier wall construction project” at the Meadowlark substation proposed in Proceeding 2180 and approved by the

⁴⁹⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF page 132, T-CBC-08-1 shows actual costs in 2013 and 2014 of \$0.42 million and \$0.30 million respectively. The work done in 2013 and 2014 included adding redundant AC systems in Petrolia and Castle Downs substations in 2013 and 2014 respectively and adding redundant DC systems in Lambton and Petrolia substations in 2013 and 2014 respectively.

⁴⁹⁶ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-114(c): the forecast cost of the project is \$0.52 million, plus \$0.5 million to complete the participant involvement program and facility application associated with this project.

⁴⁹⁷ Section 2.2(1).

⁴⁹⁸ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-114(a), PDF page 370 of 513.

⁴⁹⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 64, PDF page 146 of 433.

Commission in Decision 2013-010.⁵⁰⁰ EDTI stated that the results of the NIA concluded that the Meadowlark substation is not in compliance with the permissible sound level requirements of Section 2.1 of Rule 012.⁵⁰¹ EDTI does not, however, have any expected work planned for the Meadowlark substation that is to be completed after October 17, 2018, until 2026.⁵⁰²

635. In argument, EDTI stated: “Commission information requests and cross-examination at the hearing suggested that EDTI did not need to be compliant with the PSL requirements at Meadowlark until EDTI submitted an application to modify the substation. EDTI does not believe that this is a correct interpretation of AUC Rule 012.”⁵⁰³ EDTI argued that a proper interpretation of Section 2.2(4) of AUC Rule 012 meant that the deferred facility status of the Meadowlark substation is eliminated on October 17, 2018, with the result that EDTI must demonstrate compliance with the permissible sound levels by October 17, 2018, whether or not it expects to complete any work requiring an application to modify the substation after that date.

636. EDTI argued that this project is also justified in light of the public feedback expressing concern about the noise levels at this substation in Proceeding 2180.⁵⁰⁴ EDTI also cited potential emergency work at this substation that would require an application to the Commission and stated that it would not be feasible to delay emergency work while EDTI installed noise mitigation walls so that it could demonstrate compliance with AUC Rule 012. EDTI concluded that the proposed noise mitigation work at the Meadowlark substation is required in order to be in compliance with AUC Rule 012 and should be approved.⁵⁰⁵

Commission findings

637. It is not clear to the Commission, based on the evidence provided by EDTI on the record of this proceeding, whether the Meadowlark substation would comply with the permissible sound levels provided in Section 2.1 of AUC Rule 012 in the absence of the substation being a “deferred facility” as set out in Section 2.2. In any event, the Commission finds that this determination is not necessary at this time, given that the Meadowlark substation is a deferred facility and, in light of EDTI’s evidence that it does not have any plans in the near term after October 17, 2018, to bring an application to modify this facility.

638. While the Commission is of the view that noise mitigation measures are generally in the public interest where required by Rule 012, the Commission does not agree with EDTI’s interpretation of Section 2.2(4) of Rule 012 in this case. Specifically, the Commission considers that Section 2.2(4) only requires a deferred facility to demonstrate compliance with the permissible sound level requirements in Section 2.1 when an application is before the Commission for modification of the facility on or after October 17, 2018. In the absence of an application for modification to the facility, Section 2.2(4) does not require the deferred facility to demonstrate compliance with the permissible sound level requirements.

⁵⁰⁰ Decision 2013-010: EPCOR Distribution & Transmission Inc., Alterations to Meadowlark Substation, Proceeding 2180, Application 1608906-1, January 11, 2013.

⁵⁰¹ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-114(d), PDF page 372 of 513.

⁵⁰² Exhibit 3539-X0158, response to undertaking given by Mr. Wiles to Ms. Kellgren at Transcript, Volume 3, page 565.

⁵⁰³ Exhibit 3539-X0193, EDTI final argument, paragraph 458, PDF page 188 of 259.

⁵⁰⁴ Exhibit 3539-X0193, EDTI final argument, paragraph 460, PDF page 188 of 259.

⁵⁰⁵ Exhibit 3539-X0193, EDTI final argument, paragraphs 461-462, PDF page 189 of 259.

639. Nor is the Commission persuaded that the costs associated with this project are reasonable on the basis of the public feedback received in Proceeding 2180, or as a proactive measure in the event that emergency work is required at the Meadowlark substation.

640. With respect to the public feedback obtained in Proceeding 2180, EDTI did not identify what feedback it was referring to. The Commission notes that a concern raised by a resident in Proceeding 2180 was discussed in the decision issued in that proceeding as follows:

13. A resident facing one of the proposed concrete wall sections of the substation was concerned that additional noise may be reflected from the proposed concrete wall to their home. To address the concern, EPCOR contracted ACI Acoustical Consultants Inc. to perform a noise impact assessment for the substation. The noise impact assessment concluded that there would be no increase in noise levels to any adjacent residences. The existing comprehensive sound level at the most impacted dwelling, approximately 29 metres east of the substation property, was measured at 49.7 dBA L_{eq} nighttime. This level is below the AUC permissible sound level of 51.0 dBA L_{eq} nighttime for the area. The forecast cumulative noise including all existing noise sources and the proposed barrier walls would still be 49.7 dBA L_{eq} nighttime. EPCOR confirmed that it consulted directly with the concerned resident about the results of the noise impact assessment and stated that they were satisfied.⁵⁰⁶

641. In that decision, the Commission found the current sound levels to be below the permissible sound level for the area.

642. Based on the evidence on the record of this proceeding, including the NIA filed, the Commission is not persuaded that the current sound levels are not compliant with Section 2.1 of Rule 012.

643. With respect to potential emergency work in the future, the Commission notes Section 2.1(5) of Rule 012, which provides:

In the case of an emergency, which is an unplanned event requiring immediate action to prevent loss of life or property, the permissible sound level determined under this rule does not apply. However, if an event occurs more than four times a year at a facility, the event is not considered an unplanned event and the facility must comply with its permissible sound level.

644. The Commission anticipates that Section 2.1(5) of Rule 012 could operate to relieve EDTI of the requirement to demonstrate compliance in the emergency circumstances it postulated in this proceeding.

645. Based on the foregoing, the Commission does not approve the forecast capital additions and expenditures associated with EDTI's proposed noise mitigation project at the Meadowlark substation for the purposes of determining EDTI's revenue requirement in the test period. The Commission directs EDTI to remove the forecast costs associated with this project from its revenue requirement in its compliance filing.

⁵⁰⁶ Decision 2013-010, paragraph 13.

10.5.7.4 Substation fence grounding replacement

646. EDTI proposed replacing the substation fence bonding connections at each of its substations, beginning in 2015. The fence bonding connection is required to bond the fence to the grounding grid to protect any individual touching the fence during a fault. This ongoing project will replace existing copper bonding connections, which have been subject to theft due to their value, with new copper clad steel connections which have zero scrap value. EDTI proposes to replace the substation fence bonding connections at five substations per year, at a cost of \$0.05 million per year in the test period. The rationale for five substations per year is to smooth out capital expenditures under this project category over a number of years.⁵⁰⁷

647. In Table 9.2.3.6-1 in the application, EDTI provided references to the SEAS Substation report which provides recommendations from Quanta regarding substation fence upgrades.⁵⁰⁸ The SEAS report reference points to the Woodcroft substation fencing life cycle replacement and improvements which were planned for 2013.⁵⁰⁹ In response to a Commission IR, EDTI noted that the SEAS report also stated that “the ancillary equipment and systems must be maintained and/or replaced as needed.” and Quanta did not provide any specific recommendations regarding switchyard fencing past 2014. EDTI cautioned that this does not indicate that the proposed switchyard fence replacement program is no longer required.⁵¹⁰

Commission findings

648. The Commission is aware of the safety component which defines the need for a fence grounding system. The Commission finds EDTI’s proposal to replace the fence bonding connections at all substations to be reasonable in order to prevent emergency repairs or replacements and to prevent harm to EDTI personnel and the public. The Commission approves the forecast capital additions for the substation ancillary system life cycle replacement project for the purposes of determining EDTI’s revenue requirement for the test period. However, as EDTI did not identify how substations will be selected each year for fence bonding connection replacement, EDTI is directed to provide this information in its compliance filing and future applications.

10.5.7.5 Installation of new cable trays and cable ducts

649. Cable tray and cable duct installations is a new category of projects included in the substation ancillary system life cycle replacement projects. Similar work was previously carried out in other projects as required, such as the Garneau substation to University of Alberta (UofA) teleprotection project, which was completed in 2014.⁵¹¹ EDTI included this new project category to address the internal issue of cost increases on projects due to insufficient cable tray or cable duct space. This project involves the construction of cable ducts at substations that will require projects in the near future.⁵¹² Specifically, in the test period, EDTI proposed to install on additional cable duct at each of Victoria and Rosedale, in 2015, at Jasper in 2016 and at Lambton in 2017, as these substations are forecast to have P&C projects completed in the test period

⁵⁰⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 51-53, PDF page 142 of 433.

⁵⁰⁸ Exhibit 0003.00.EDTI-3539, Appendix E-1, Table 9.2.3.6-1, PDF page 840 of 900.

⁵⁰⁹ Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 37 of 91.

⁵¹⁰ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-083(b), PDF pages 282-283 of 513.

⁵¹¹ Exhibit 3539-X0084, Attachment 4, PDF page 3 of 12: “A \$0.03 million increase in material costs related to additional tray and wiring requirements at both EDTI’s Garneau Substation and the UofA’s North Bus location due to inadequate space in existing trays.”

⁵¹² Transcript, Volume 3, page 567.

which will require additional cable ducts and trays.⁵¹³ EDTI stated that it is not aware of any other feasible alternatives to the proposed new cable duct project.⁵¹⁴ The annual forecast costs are \$0.63 million in 2015, \$0.63 million in 2016 and \$0.41 million in 2017.⁵¹⁵ The difference in cost between the test years is due to differing lengths of cable duct required at each.⁵¹⁶

650. Also included in this project category is a “one off” project to replace the cable tray foundation at EDTI’s Genesee substation. The cable tray foundation is approximately 28 years old and has moved over time causing the cable tray to collapse. This project is forecast to be completed in 2015 at a cost of \$0.08 million.⁵¹⁷

Commission findings

651. The Commission acknowledges EDTI’s statement that the purpose of this project is to increase cable tray and duct capacity in advance of other projects, which will require this additional capacity. The Commission considers this to be a reasonable solution to the issues encountered with project cost increases observed in the last test period, due to insufficient cable tray and duct space. The Commission approves the forecast capital additions for this substation ancillary system life cycle replacement project for the purposes of determining EDTI’s revenue requirement in the test period.

10.5.8 Medium voltage switchgear replacement (reference 9.2.2.11)

652. This is an ongoing life cycle replacement program which consists of replacing the 15-kV metal clad switchgears installed at EDTI’s substations. This program was initiated as a result of a number of failures experienced on the 15-kV metal clad switchgear in recent years. In 2010, EDTI completed a comprehensive study of its MV switchgears to determine the condition of the switchgears and the potential consequences of not replacing these assets, and to develop a long-term replacement plan. The study determined that the switchgear at Hardisty substation had reached the end of its useful life⁵¹⁸ and that it does not meet the applicable arc-resistance standards.⁵¹⁹ The SEAS report also identified the MV switchgear at Hardisty as in need of being upgraded.⁵²⁰

653. This project is planned to be completed in three stages due to the complexity of replacing the switchgear, switching constraints related to offloading affected circuits and the risk of extended outages, as described by EDTI, below:

Stage 1: Add two cells to the bus 1 switchgear and then replace the nine existing cells associated with the bus 1 switchgear. The majority of the work completed in this stage will be completed and put into service in 2015.

⁵¹³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 54-55, PDF page 143 of 433.

⁵¹⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 65 PDF page 146 of 433.

⁵¹⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 55, PDF page 143 of 433.

⁵¹⁶ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-082(d), PDF page 280 of 513 states that the cable duct lengths are 40 metres each at Victoria and Rosedale, 85 metres at Jasper and 48 metres at Lambton.

⁵¹⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 56-57, PDF pages 143-144 of 433.

⁵¹⁸ Exhibit 0003.00.EDTI-3539, application, paragraphs 2214 and 2217, PDF page 759 of 900.

⁵¹⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 6, PDF page 152 of 433.

⁵²⁰ Table 9.2.3.6-1 in the application (Exhibit 0003.00.EDTI-3539) refers to page 22 of the SEAS substation assessment which states: “The metalclad switchgear averages more than 44 years old and is the old Westinghouse type DH air magnetic circuit breakers. The condition of this equipment ranks it second only to Namao as most in need of upgrade.”

Stage 2: Transfer the two new cells added to the bus 1 switchgear to the bus 2 switchgear. These cells will be used to replace two of the existing nine bus 2 switchgear cells. The remaining seven bus 2 switchgear cells will then be replaced and two new cells will be added to the bus 2 switchgear. These additions and replacements are forecast to come into service and be added to rate base in 2016.

Stage 3: The two new cells which were added to the bus 2 switchgear will be transferred to the bus 3 switchgear. These cells will be used to replace two of the existing seven bus 3 switchgear cells. The remaining five bus 3 switchgear cells will then be replaced. This replacement is forecast to come into service and be added to rate base in 2017.⁵²¹

654. As an attachment to the business case, EDTI provided the 15-kV metal clad switchgear study. In the table provided showing MV switchgears at all substations, the calculated RI for Hardisty was the second highest score after Namao.⁵²² EDTI is currently in the process of replacing the switchgear at Namao. Based on the RI score and nature of the issues identified at Hardisty, EDTI proposed to replace the 15-kV metal clad switchgear at Hardisty in the test period. The RI scores for Victoria, Rosedale and Garneau substations are similarly high. However, the replacements are being addressed in separate project categories (MV switchgear addition projects at Victoria and Rosedale and the South Central Transmission Reinforcement project at Garneau).⁵²³ The RI score for Hardisty was determined based on the age and design of the circuit breakers, the condition of the circuit breakers and the condition and design of the PILC cable terminations. The MV switchgear at Hardisty has MV circuit breakers with an obsolete air/magnetic interrupting design making them difficult and expensive to maintain and prone to certain conditions which can cause them to fail. EDTI is proposing to install a new switchgear with circuit breakers which will not have the design issues identified in the study⁵²⁴ and in a double bus configuration which will remove the switchgear configuration issues.⁵²⁵

655. The forecast capital additions for this project are \$4.16 million in 2015, \$3.36 million in 2016 and \$2.94 million in 2017.⁵²⁶ This includes capital expenditure forecasts for contractors of \$2.64 million in 2015, \$2.00 million in 2016 and \$1.69 million on 2017.⁵²⁷ The costs forecast are not based on historical costs or the historical number of projects completed.⁵²⁸

656. EDTI evaluated three alternatives for this project: (1) emergency repair or replacement, (2) upgrade existing switchgear, upgrade feeder protection and replace PILC cable terminations, and (3) replace existing switchgear with arc resistant switchgear and PILC cable terminations. EDTI rejected the first alternative on the basis that it would not address the deteriorating condition of the MV switchgear and would result in an increased probability of prolonged forced outages of equipment, would increase risk to EDTI personnel, would not address safety concerns and would only defer the need to replace the switchgear. EDTI rejected the second alternative on the basis that it was less economic than alternative three and it presented numerous deficiencies

⁵²¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 7, PDF page 152 of 433.

⁵²² Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-09-7, PDF page 160 of 433.

⁵²³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 7-8, PDF page 160 of 433.

⁵²⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 10, 13 and 14, PDF pages 161 and 163 of 433.

⁵²⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 17, PDF page 170 of 433.

⁵²⁶ Exhibit 3539-X0128.01.

⁵²⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, Table T-CBC-09-3, PDF page 153 of 433.

⁵²⁸ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-040(b), PDF page 299.

as compared to alternative three.⁵²⁹ EDTI cited additional benefits associated with alternative three including simplified maintenance and reduced space requirements (the new compact switchgear is 40 per cent smaller than air-insulated switchgears).⁵³⁰

657. None of the parties discussed this project in argument or reply.

Commission findings

658. The cost forecasts for the 15-kV metal clad switchgear life cycle replacement project are based on a bottom up approach. The Commission finds that the study provided by EDTI supports the scope and timing of the project, and therefore finds that the forecast costs are reasonable. Accordingly, the Commission approves the forecast capital additions for the 15-kV metal clad switchgear life cycle replacement project for the purposes of determining EDTI's revenue requirement in the test period.

10.5.9 500-kV air blast circuit breaker life cycle replacement (reference 9.2.2.12)

659. The 500-kV air blast circuit breaker (ABCB) life cycle replacement project is a multi-year project to replace four 500-kV ABCBs at EDTI's Genesee substation. These four breakers had been refurbished in 2006 and, at the time the decision was made for refurbishment, EDTI expected that the service lives of the ABCBs would be extended by 15 to 20 years.

660. However, loss of air pressure due to air leaks previously experienced by all four refurbished breakers during cold weather in January 2012 caused two ABCBs to go into a lock out condition, which increased the risk of the Genesee generator and/or sections of the associated transmission line becoming inoperable. In April 2012, EDTI determined that the original equipment manufacturer would no longer support the refurbished ABCBs and EDTI subsequently proposed in its 2013-2014 GTA that all four ABCBs should be replaced.

661. EDTI had originally forecast in its 2013-2014 GTA that one ABCB would be replaced each year in 2013 through 2016. However, in this application, and in order to avoid construction conflicts with the Genesee generating station expansion project, EDTI proposed that the two remaining ABCBs should both be replaced in the year 2015.

662. Actual capital additions for the years 2013 and 2014 when combined, exceeded approved forecast capital additions in the amount of \$0.35 million.⁵³¹ EDTI stated these cost overages were due primarily to higher than expected labour costs and other associated costs.

663. During the hearing, EDTI was asked to explain why the average forecast cost to replace the remaining two ABCBs, when considered on a per unit basis, would increase as compared to the 2014 actual cost to replace a single ABCB.⁵³² EDTI stated that the 23 per cent increase in

⁵²⁹ The main bus insulation would not be upgraded and the deterioration due to partial discharge would continue, EDTI personnel would still be exposed to potential hazards and the concerns related to obtaining bus outages for maintenance and the consequences associated with bus faults would not be addressed.

⁵³⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 154-158 of 430.

⁵³¹ Exhibit 3539-X0086, Attachment 2, CWIP continuity schedule updated for 2014 actuals (\$0.65+\$0.78-\$0.95-\$0.83).

⁵³² EDTI's actual cost to replace an ABCB in 2014 was \$0.83 million. EDTI forecast to replace two ABCBs in 2015 at a cost of \$2.03 million (or an average unit cost of \$1.02 million).

forecast cost per unit was the result of increases in equipment rental costs, costs to decommission the system and additional SCADA work required to connect the final two ABCB replacements.⁵³³

664. In the evidence submitted by the UCA, Mr. Bell questioned why the balance of the replacement project could not be deferred until a future GTA. This was based on EDTI's IR response which indicated additional maintenance and inspection costs incurred in the years 2012-2014 of approximately \$1,200 related to the ABCBs,⁵³⁴ had been minimal. The UCA recommended that the Commission find that EDTI has not adequately demonstrated why the 500-kV ABCB life cycle replacement project is required in the test period and that the forecast capital additions be denied.⁵³⁵

665. EDTI replied that the UCA suggestion to defer the replacement of the ABCBs to future test periods would result in increased safety risks to the public and EDTI staff that could result in unnecessary or excessive customer outage times and potentially higher costs.

666. In response to the UCA's assertions that, should the ABCBs experience another lock out condition during periods of cold weather, EDTI had the option of sending out a repair crew. EDTI responded that the design of the breakers makes them susceptible to air leaks and as it is not a breaker designing facility, its crews are not able to repair all possible types of air leaks. Further, given the importance of the Genesee generating station, EDTI would not want the switchyard shut down, thereby reducing supply in cold weather.⁵³⁶

Commission findings

667. In previous GTAs, EDTI provided support for the replacement of the four ABCBs, the final two of which are to be replaced in 2015. In this proceeding, EDTI has explained the susceptibility of the ABCBs to leaks in cold weather, as indicated by the 2013 lockout, and the consequences of a shutdown of the ABCBs. Specifically, if the ABCBs were to shut down, the Genesee switchyard would be shut down, reducing supply in a period of cold weather. The Commission finds that EDTI has provided sufficient support for the requirement to replace the remaining two ABCBs. EDTI has proposed to replace the two remaining ABCBs in 2015, rather than one each in 2015 and 2016, due to possible scheduling difficulties in 2016 when the Genesee expansion project will be ongoing. The Commission finds EDTI's proposal to replace the two remaining ACBCs in 2015 to be reasonable.

668. The Commission does not agree with the UCA that the minimal costs related to maintenance and inspections in 2013-2014 are a sufficient indicator that the project is not required or can be deferred to future periods.

669. Based on the foregoing, the Commission approves EDTI's forecast costs associated with replacing the remaining two ABCBs in 2015 as applied-for, for the purposes of determining EDTI's revenue requirement in the test period.

⁵³³ Exhibit 3539-X0162, undertaking at Transcript, Volume 3, page 577.

⁵³⁴ Exhibit 3539-X0034, IR responses to EDTI-UCA-2015Feb05-041.

⁵³⁵ Exhibit 3539-X0051, page 17.

⁵³⁶ Transcript, Volume 1, pages 181-183.

10.5.10 Power transformer replacement (reference 9.2.2.13)

670. This is an ongoing life cycle replacement program which consists of the replacement of EDTI's power transformers (also referred to as transmission transformers).⁵³⁷ Power transformers are required to step down voltages from transmission to distribution voltages.⁵³⁸

671. In the test period, EDTI proposed to replace one power transformer (Tx2) at the Victoria substation and to add a new oil containment pit around the existing pad. The transformer was selected on the basis of its age and condition. The transformer is 46 years old and the expected service life of power transformers is 45 years.⁵³⁹ Since 2000, this transformer has experienced 47 faults.⁵⁴⁰ Additionally, EDTI identified a number of operational and condition based issues with the power transformer, including:

- Due to the location of the load tap changer (LTC) on the transformer, the LTC is directly exposed to high electrical stresses which has caused the LTC to fail multiple times. Also, the dissolved gas analysis (DGA) test results for the LTC diverter switch compartment shows increasing levels of hydrogen and acetylene.⁵⁴¹
- The LTC motor drive mechanism leaks oil onto internal mechanism components which activates the out of step alarm which requires a field crew to manually reset the relay and unblock the LTC operation; the leak cannot be repaired as the damaged part is no longer manufactured and cannot be replaced. Due to this issue, EDTI only uses Victoria Tx2 to supply power under emergency conditions.⁵⁴²
- The core insulation test performed in 2014 showed signs of insulation (oil and paper) deterioration which can result in an increased risk of the transformer failing.
- The bolts related to the core steel clamping structure have loosened over time causing the core sheets to vibrate which increases the noise level emitted from the transformer; this is expected to worsen over time. The vibration of the core steel sheets may also lead to a transformer core insulation failure which could cause a catastrophic transformer failure.⁵⁴³
- The transformer has winding deformations which can cause the transformer to fail if there is a fault on the distribution circuit fed from the transformer.
- The transformer does not have an oil containment pit.⁵⁴⁴

672. Table 9.2.3.6-1 in the application references the SEAS report as justification for the Victoria power transformer replacement⁵⁴⁵ but the referenced page of the report pertains to non-LTC transformers in Namao, Hardisty and Strathcona substation.⁵⁴⁶ However, the SEAS report, describes the decision making process utilized to assess the condition of the transformer.⁵⁴⁷ The

⁵³⁷ Transcript, Volume 3, page 574.

⁵³⁸ Exhibit 0003.00.EDTI-3539, application, paragraph 2257, PDF page 769 of 900.

⁵³⁹ Exhibit 0003.00.EDTI-3539, application, paragraph 2257, PDF page 769 of 900.

⁵⁴⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 15, PDF page 185 of 433.

⁵⁴¹ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 6, PDF page 183 of 433. Also, in response to EDTI-UCA-2015FEB06-042(b) in Exhibit 3539-X0034, it was noted that IEEE C57.106 provides a guide for transformer insulating oil conditions though it provides criteria related to oil reclamation, not transformer replacement.

⁵⁴² Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 10, PDF page 184 of 433.

⁵⁴³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 13, PDF page 185 of 433.

⁵⁴⁴ Exhibit 0003.00.EDTI-3539, application, paragraphs 2255-2258, PDF pages 769-770 of 900.

⁵⁴⁵ Exhibit 0003.00.EDTI-3539, application, Table 9.2.3.6-1, PDF page 840 of 900.

⁵⁴⁶ Exhibit 0050.00.EDTI-3539, Appendix G-1, PDF page 48 of 91.

⁵⁴⁷ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-083(c), PDF page 283. This response defines the decision making process as that outlined on page 40 of the Substation and Terminal Assessment SEAS report.

AHI included in the SEAS for Victoria Tx2 is a score of 1.123, which is in the “good” condition range.⁵⁴⁸

673. EDTI indicated it intends to complete this project over the years 2016 and 2017, and to include the total capital additions in rate base in 2017 when the project is complete. The total forecast capital additions for this project are \$3.10 million. The largest component of the project costs is the cost of materials.⁵⁴⁹

674. EDTI considered and rejected repairing the existing power transformer. To repair the transformer, it would need to be taken out of service for at least one year, repair does not address the age and condition of the transformer, and the NPV of the repair alternative is expected to be greater than the replacement NPV. Further, a spare transformer to replace Victoria Tx2, should it be taken off site for repairs, is not available.⁵⁵⁰ Also, EDTI explained that consideration was given to replacing the tap changer to deal with the leaky motor mechanism and the location of the LTC. However, this was rejected as it is not reasonable to replace the tap changer on a transformer that will be retired from service in five to six years.⁵⁵¹ Therefore, EDTI proposes to replace the transformer.⁵⁵²

675. In the evidence submitted by the UCA, Mr. Bell asserted that there is no detailed quantitative analysis of the impact of not pursuing this project, from a service quality or safety perspective. Mr. Bell added that EDTI has known about a number of the issues identified as requiring the replacement of the power transformer for a while and EDTI had provided no evidence as to why this work was not done earlier or could not be deferred one or more test periods.⁵⁵³ The UCA recommended that the Commission find that EDTI has not adequately demonstrated why the power transformer life cycle replacement project is required in the test period and that the forecast capital additions be denied.⁵⁵⁴

676. EDTI reiterated in its rebuttal evidence that the power transformer replacement is required to address all six issues identified with the transformer and noted that Mr. Bell’s evidence only spoke to the first issue.⁵⁵⁵ EDTI further expounded on its evidence of increasing levels of hydrogen and acetylene⁵⁵⁶ found in the transformer oil in the diverter switch compartment:

Typically, a significant amount of fault energy is required to produce acetylene, which is formed from the breakdown of oil at temperatures in excess of 700°C. Excessively high overheating of the oil will produce acetylene gas in low concentrations. The higher concentrations of acetylene gas are typically associated with presence of sustaining arcing in the transformer and are often symptomatic of a more serious operational issue that can cause a transformer failure if left unchecked.⁵⁵⁷

⁵⁴⁸ Exhibit 0050.00.EDTI-3539, Appendix G-1, Table 4-1, PDF page 42 of 91.

⁵⁴⁹ Exhibit 0030.00.EDTI-3539, Appendix E-1, tables T-CBC-11-1 and T-CBC-11-2, PDF page 187 of 433.

⁵⁵⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 13, PDF page 185 of 433.

⁵⁵¹ Transcript, Volume 1, page 190.

⁵⁵² Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 33, 38 and 40, PDF pages 190-192 of 433.

⁵⁵³ Exhibit 3539-X0051, page 15.

⁵⁵⁴ Exhibit 3539-X0051, page 17.

⁵⁵⁵ Exhibit 3539-X0071, PDF page 60, A47.

⁵⁵⁶ Exhibit 0030.00.EDTI-3539, Appendix E-1, T-CBC-11, paragraph 6, PDF page 183 of 433.

⁵⁵⁷ Exhibit 3539-X0071, PDF page 60, A47.

677. In EDTI's view, the information provided in the business case and in response to IRs adequately demonstrates that the project is required as proposed.⁵⁵⁸

678. In rebuttal, EDTI reiterated that Victoria substation has four power transformers, that the station can be operated with three transformers and that due to the defective tap changer, Victoria Tx2 cannot be operated in parallel with the other transformers. Accordingly, Victoria Tx2 has not been operating since 2013 except in emergencies.⁵⁵⁹

679. The UCA argued that none of the drivers of the power transformer life cycle replacement project are new and there is no reason why this project should be funded in this period. As such, the UCA recommended the forecast capital additions be denied.⁵⁶⁰

680. In argument, EDTI noted that Mr. Bell is not an engineer but in his evidence, he provided an interpretation of fluid quality analysis and opined on whether the analysis supports the replacement of the power transformer. EDTI argued that Mr. Bell's evidence and conclusions should be given no weight.⁵⁶¹

Commission findings

681. The SEAS report lists four transformers⁵⁶² at Victoria substation and notes that EDTI identified Tx2 as being used in emergency conditions only, since 2013. Additionally, the SEAS Substation and Terminal Assessment report scores Victoria Tx2 as being in "good" condition. However, the Tx2 transformer at 46 years old exceeds the average expected service life of power transformers of 45 years. The Commission accepts EDTI's evidence that numerous operational and condition based issues have arisen with this transformer since the completion of the SEAS study. The Commission further accepts EDTI's evidence that certain of these issues⁵⁶³ cannot be addressed without replacement of a component of the transformer, such as the tap changer, or replacement of the entire transformer.

682. The Commission has reviewed the business case and the justification provided for this project and finds that the evidence provided regarding operational and condition-based issues adequately supports replacing the transformer. Accordingly, the Commission approves the forecast capital additions for the power transformer replacement project, including the proposed oil containment pit, for the purposes of determining EDTI's revenue requirement in the test period.

10.5.11 Medium voltage switchgear additions – Rosedale (reference 9.2.2.14) and Victoria (reference 9.2.2.15)

683. The Rosedale and Victoria MV switchgear additions projects (Rosedale and Victoria projects) are similar in nature and were often treated together on the evidentiary record. They are therefore addressed together in this section.

⁵⁵⁸ Exhibit 3539-X0071, PDF pages 62-63.

⁵⁵⁹ Transcript, Volume 1, page 190.

⁵⁶⁰ Exhibit 3539-X0196, paragraphs 60 and 68, PDF pages 17-18.

⁵⁶¹ Exhibit 3539-X0193, paragraph 486, PDF page 197 of 259.

⁵⁶² Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 35 of 91.

⁵⁶³ For example, EDTI stated that the issue of leaking oil onto the internal mechanism components cannot be repaired.

684. These projects are one-time life cycle replacements which consist of adding one 15-kV metal clad switchgear in each of the Rosedale and Victoria substations and transferring the network feeders to the new switchgears. The Rosedale project began in 2013 and is forecast to be completed and added into rate base in 2015 and 2017.⁵⁶⁴ The Victoria project began in 2014 and is forecast to be completed and added into rate base in 2017.⁵⁶⁵

685. Each project has four drivers:

- the need to reduce high fault levels on the 15-kV buses
- the need to reduce arc flash risk from the downtown network distribution feeders
- the need to replace the aging 15-kV metal clad switchgear
- the need to meet the demands of load growth in the Edmonton downtown area and UofA south campus⁵⁶⁶

686. In 2013, EDTI retained Quanta to investigate the existing conditions and hazards of the downtown or secondary network which are part of EDTI's distribution assets.⁵⁶⁷ Quanta's report, provided as an attachment to an IR response,⁵⁶⁸ recommended that the fault levels be reduced and concluded that the arc flash risk could be reduced by eliminating the 600 volt (V) spot networks and supplying customers with radial primary service. The majority of the work associated with the latter recommendation is currently being considered by the Commission in EDTI's Capital Tracker proceeding (Proceeding 20407).⁵⁶⁹ The Quanta network report recommended the following two tasks in 2015 and 2016:

2015: Construct a new 15 kV GIS bus at Rosedale, install new switchgear and transfer eight existing network feeders to the new Rosedale switchgear.

2016: Construct a new 15 kV GIS bus at Victoria, install new switchgear and transfer seven existing network feeders to the new Victoria switchgear.⁵⁷⁰

687. EDTI confirmed that these two tasks would be completed by transmission because EDTI considers that, while 15-kV and 25-kV voltages are distribution, all equipment in the substation is considered transmission.⁵⁷¹ The proposed switchgear additions in Rosedale and Victoria substations will be entirely funded by transmission with no contributions from distribution. EDTI considers that regardless of the network reconfiguration project proposed by Quanta, which is being completed by EDTI distribution, the need for additional switchgears at Rosedale and Victoria substations remains in order to address the fact that the circuit breakers cannot properly interrupt the existing current fault levels at those substations.⁵⁷² The proposed switchgears will be arc resistant, and therefore less likely to be damaged by arc flash events.⁵⁷³ EDTI's witness confirmed that the addition of the proposed switchgears will improve the arc flash risk even if

⁵⁶⁴ Exhibit 0003.00.EDTI-3539, application, paragraph 2268, PDF page 772 of 900.

⁵⁶⁵ Exhibit 0003.00.EDTI-3539, application, paragraph 2287, PDF page 777 of 900.

⁵⁶⁶ Exhibit 0003.00.EDTI-3539, application, paragraph 2269, PDF pages 772-773 of 900.

⁵⁶⁷ Transcript, Volume 3, page 517.

⁵⁶⁸ Exhibit 3539-X0012, PDF pages 62 to 235, EDTI-CCA-2015FEB06-016 Attachment 1.

⁵⁶⁹ Proceeding 20407, EDTI 2014 True-up PBR Capital Tracker and 2016-2017 PBR Capital Tracker Application.

⁵⁷⁰ Exhibit 3539-X0012, PDF page 235, Table A-1.

⁵⁷¹ Transcript, Volume 3, page 517.

⁵⁷² Transcript, Volume 3, pages 521-522.

⁵⁷³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 18, PDF page 205 of 433.

the remaining secondary network reconfiguration work is not undertaken by distribution, though the additions will not completely solve the distribution arc flash and fault levels problem.⁵⁷⁴

688. The SEAS report for Substation and Terminal Station Assessment also noted that a large number of circuit breakers at Victoria and Rosedale substations are operating at elevated fault levels (above 90 per cent) and good utility practice is to limit the levels to 80 per cent of the circuit breaker rating and 70 per cent of the interrupting rating. Quanta made note of the switchgear addition projects which have been initiated for Rosedale and Victoria substations, and concluded that this will result in lower current levels and provides ample fault interrupting margins for the older switchgears.⁵⁷⁵

689. An additional driver of these projects is the aging switchgear at both substations. EDTI completed a study of the condition of the switchgears. The study determined that the switchgear at Victoria will reach the end of its useful life and should be replaced in the 2027 to 2030 timeframe⁵⁷⁶ and the switchgear at Rosedale will reach the end of its useful life and should be replaced in the 2030 to 2033 timeframe.^{577 578} Before the existing switchgears can be removed, an additional 15-kV switchgear must be installed in each of the substations to better enable EDTI to move the distribution feeders from the existing switchgear to the new switchgear. Because the substations cannot currently accommodate the addition of a switchgear, EDTI proposes to expand the substations.⁵⁷⁹

690. The Rosedale building expansion proposed in EDTI's 2013-2014 application was intended to expand the building in 2014 and add the new switchgear in 2015. The proposed expansion is complex because the site is congested with surface and subsurface elements which cannot easily be relocated and because the site has historical significance. EDTI commissioned an engineering feasibility study, which analyzed four options for expanding the building and recommended that EDTI proceed by expansion to the north of the Rosedale substation. This option requires EDTI to move existing infrastructure before building the new substation building, resulting in a new timeline for the project.⁵⁸⁰ EDTI, at the time of the hearing, was in negotiations with the City of Edmonton to transfer the land for the Rosedale expansion.⁵⁸¹

691. The Victoria building expansion requires additional land. EDTI acquired the land in 2014 at a cost of \$1.14 million.⁵⁸² These costs, included in the forecast cost, will be added to rate base when the switchgear is energized in 2017.⁵⁸³ However, EDTI confirmed that the cost to purchase

⁵⁷⁴ Transcript, Volume 3, page 523.

⁵⁷⁵ Exhibit 0050.00.EDTI-3539, Appendix G-11, PDF page 65 of 91.

⁵⁷⁶ Exhibit 0003.00.EDTI-3539, application, paragraph 2292, PDF page 778 of 900.

⁵⁷⁷ Exhibit 0003.00.EDTI-3539, application, paragraph 2272, PDF page 773 of 900.

⁵⁷⁸ The timeframe for switchgear replacement was determined as part of the 15-kV metal clad switchgear study which was provided as an attachment to the business cases. The study ranked the switchgears at all substations based on asset health and consequence of failure. Victoria had the third highest risk index and Rosedale was fourth highest.

⁵⁷⁹ Exhibit 0003.00.EDTI-3539, application, paragraph 2293, PDF page 778 of 900.

⁵⁸⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 19-21, PDF pages 205-206 of 433.

⁵⁸¹ Transcript, Volume 3, page 531.

⁵⁸² Transcript, Volume 3, page 531.

⁵⁸³ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 20, PDF page 226 of 433.

the land was \$364,000 less than the original estimate,⁵⁸⁴ but the forecast was not adjusted for the lower purchase price of the land.⁵⁸⁵

692. In response to an IR, EDTI confirmed that it intends to use the new SF6 type switchgear which is 40 per cent smaller than the existing air insulated switchgear. However, the new switchgear has a configuration that increases the overall length of the switchgear so the space saving is not 60 per cent and the building expansions are still required.⁵⁸⁶

693. The final driver for these projects is the need to ensure there is sufficient capacity to meet the anticipated load growth in the Edmonton downtown area. EDTI expects that an additional switchgear cell will be required in the Victoria substation by 2018 to meet the load growth in the Blatchford area,⁵⁸⁷ and an additional switchgear cell will be required in the Rosedale substation by 2020 in order to meet the load growth in the Garneau and UofA south campus area.⁵⁸⁸ Currently, there are only three vacant cells at Rosedale, which EDTI intends to use to supply the downtown arena in 2015, and the additional expected load in the Garneau area in 2016 and in 2019.⁵⁸⁹ There are also only three vacant cells at Victoria, which EDTI intends to use to supply new buildings forecast to be built in the Edmonton downtown in 2016 (requires two cells, leaving only one empty cell). EDTI anticipates that two additional cells will then be required due to additional load in the downtown area by 2020 and two more cells will be required by 2025 to supply the Blatchford residential area.⁵⁹⁰

694. For the Rosedale project, EDTI is forecasting to add \$3.68 million to rate base in 2015 and \$10.55 million in 2017.⁵⁹¹ This includes \$0.05 million for an arc flash, arc blast and protection coordination study completed in 2012, which was completed to calculate and compare the short circuit withstand capability of the switchgear and current fault levels of the 15-kV bus. The total amount also includes \$0.16 million incurred in 2013 for a feasibility study and preliminary engineering work related to the project.⁵⁹² For the Victoria project, EDTI is forecasting to add \$15.79 million in rate base in 2017⁵⁹³ which includes opening CWIP of \$1.37 million from costs incurred in 2014.⁵⁹⁴ EDTI noted that the cost estimates are at a preliminary engineering level only and the accuracy is +/-50 per cent.⁵⁹⁵

695. The forecast costs for these projects were based on the following:

- EDTI completed an RFP for the work to be completed by contractors and selected the lowest bid as the basis for the contractor cost forecasts.
- The material costs were calculated based on estimates received from manufacturers.

⁵⁸⁴ Transcript, Volume 3, page 481.

⁵⁸⁵ Exhibit 3539-X0172.

⁵⁸⁶ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-089(b), PDF page 294.

⁵⁸⁷ Exhibit 0003.00.EDTI-3539, application, paragraph 2294, PDF page 778 of 900.

⁵⁸⁸ Exhibit 0003.00.EDTI-3539, application, paragraph 2274, PDF page 774 of 900.

⁵⁸⁹ Exhibit 0030.00.EDTI-3539, Appendix E-11, paragraph 15, PDF page 204 of 433.

⁵⁹⁰ Exhibit 0030.00.EDTI-3539, Appendix E-11, paragraph 15, PDF page 225 of 433.

⁵⁹¹ Exhibit 3539-X0128.01.

⁵⁹² Exhibit 0003.00.EDTI-3539, application, PDF page 776 of 900.

⁵⁹³ Exhibit 3539-X0128.01.

⁵⁹⁴ Exhibit 0003.00.EDTI-3539, application, Table 9.2.2.15-1, PDF page 780 of 900.

⁵⁹⁵ Exhibit 0030.00.EDTI-3539, Appendix E-11, paragraph 27, PDF page 207 of 433.

- Engineering and labour cost forecasts are calculated based on the amount of time EDTI expects each resource will require to complete the work. The forecast number of hours and rates by resource type were provided in an attachment to an IR response.⁵⁹⁶

696. At a high level, the difference in costs between the switchgear addition projects at Rosedale and Victoria is due to differences in scope.⁵⁹⁷ There are also differences in SCADA requirements attributed to a new building at Victoria as compared to the building expansion at Rosedale,⁵⁹⁸ and differences in engineering requirements.⁵⁹⁹

697. In response to questioning about the difference between approved and actual costs in 2013 and 2014 related to the Rosedale project, EDTI's witness stated that the project was delayed in that test period and continues to be delayed due to difficulties with getting First Nations to participate in the consultation process. However, EDTI anticipated that the scope of the project for 2015 can still be implemented.⁶⁰⁰

698. Quanta's witness confirmed that these projects should be synchronized, as one project cannot be implemented without the other.⁶⁰¹ Also, when questioned about whether converting the existing transmission system to 240 kV would change the need for these projects and for the substation expansion, EDTI's witness confirmed that the conversion would not change the fault levels and the switchgears would still be required.⁶⁰² The Quanta witness confirmed that there is no alternative that would integrate the additional switchgears into the existing substations footprint if the conversion 240 kV were to be completed.⁶⁰³

699. EDTI considered five alternatives for each of these projects: (1) do nothing, (2) upgrade part of the existing switchgear to meet the fault current levels, (3) install feeder reactors, (4) replace the existing substation and (5) add new switchgear and transfer the network feeders to the new switchgear. EDTI rejected the first alternative on the basis that it would not achieve the purpose of the project. The second alternative proposes to replace the air circuit breakers with modern design vacuum circuit breakers, install arc flash detection equipment and retrofit the switchgear to reduce the effects of an arc flash. Under this alternative, one switchgear bus would be upgraded every year. EDTI rejected this alternative on the basis that it will not address fault levels and it does not enable EDTI to add future breaker cells for distribution load growth. The third alternative proposes to add 28 fault current reducing reactors between 2015 and 2018, and a new project to add a switchgear (and expand the building) would begin in 2018 for Victoria and 2019 for Rosedale. EDTI rejected this alternative on the basis that it will not reduce the risk of 15-kV fault levels exceeding the switchgear short circuit-withstand and the interrupting capability of the circuit breakers, EDTI would be unable to convert the 600 V spot networks and it does not enable EDTI to add future breaker cells. EDTI rejected the fourth alternative on the basis of cost. EDTI selected the fifth alternative as the lowest cost alternative that will allow EDTI to reduce the fault levels on the 15-kV buses, reduce the arc flash risk, meet load growth in

⁵⁹⁶ Exhibit 3539-X0005, PDF pages 311-317, EDTI-AUC-2015FEB06-093(d), (f) and Attachment 1.

⁵⁹⁷ Exhibit 3539-X0152.

⁵⁹⁸ Exhibit 3539-X0151.

⁵⁹⁹ Exhibit 3539-X0150.

⁶⁰⁰ Transcript, Volume 3, page 480.

⁶⁰¹ Transcript, Volume 6, pages 1169-1170.

⁶⁰² Transcript, Volume 3, page 525.

⁶⁰³ Transcript, Volume 6, page 1194.

the downtown area, replace the aging switchgears and lastly, this alternative was recommended by Quanta.⁶⁰⁴

700. In the evidence submitted by the UCA, Mr. Bell asserted that there is no detailed quantitative analysis of the impact of not pursuing this project, from a service quality or safety perspective.⁶⁰⁵ Additionally, EDTI has known about a number of the issues identified as requiring additional switchgears for a while and logically, if the additional switchgear cells are required due to growth by 2019 for Rosedale and 2025 for Victoria, and it takes three years for the project to be completed, these projects could be delayed until a future GTA.⁶⁰⁶ Mr. Bell recommended that the Commission find that EDTI has not adequately demonstrated why the switchgear addition projects are required in the test period and recommended that the forecast capital additions be denied.⁶⁰⁷

701. In its rebuttal, EDTI contended that Mr. Bell focused solely on the load growth driver while ignoring the safety, reliability and aging infrastructure issues with respect to the three other project drivers discussed in EDTI's evidence. EDTI reiterated that the projects are required irrespective of the capacity driver.⁶⁰⁸ Furthermore, EDTI contended that even though EDTI had only identified the currently known future need for switchgear cells, this does not equate to an ability to delay the projects until such a time as the load growth occurs.⁶⁰⁹

702. In argument, the UCA noted that the four drivers identified by EDTI for these projects are not new: EDTI first became aware of the fault level issues in 2007. The UCA's argument also noted that EDTI had indicated in the business case that arc flashing is a result of faults and should be treated as one driver. Logically, if the arc flashing is caused by the fault levels, then solving the problem of increased fault levels would also solve the arc flashing. Also, the UCA noted that the costs of these projects are heavily weighted in 2017 and contended that if the projects were critical, one would expect that they would have been done before the test period or at least, not at the end of the test period. The UCA maintained that there is insufficient evidence to justify the inclusion of the projects in rates at this time and the proposed capital additions should be denied.⁶¹⁰

703. In reply, EDTI pointed out that the UCA's assertions with regards to the timing of projects are based on the timing of capital additions which does not reflect the work in years prior to the year in which an asset is put into service. The fact that capital additions occur in 2017 simply reflects the fact that projects require a number of years to engineer, design, construct and complete. EDTI maintained that Mr. Bell's evidence and the UCA's argument should be rejected.⁶¹¹

Commission findings

704. The evidence on the record indicates that these projects are required to address system growth, safety and reliability issues related to high fault levels and arc flash risk, and aging

⁶⁰⁴ Exhibit 0003.00.EDTI-3539, application, paragraphs 32-39, PDF pages 209-211 of 900.

⁶⁰⁵ Exhibit 3539-X0051, page 14.

⁶⁰⁶ Exhibit 3539-X0051, page 15.

⁶⁰⁷ Exhibit 3539-X0051, page 17.

⁶⁰⁸ Exhibit 3539-X0071, PDF page 68.

⁶⁰⁹ Exhibit 3539-X0071, PDF page 64.

⁶¹⁰ Exhibit 3539-X0192, PDF pages 17-18.

⁶¹¹ Exhibit 3539-X0197, paragraphs 157, 158 and 163, PDF pages 58 and 60.

switchgears. The current condition of the existing switchgears, as found in the AHI, are both shown to have a high risk level, and replacement is recommended for both, within 15 years. As was demonstrated with respect to the MV switchgear replacement project (addressed in Section 10.5.8 above), replacing a switchgear without the benefit of an additional switchgear available to which buses can be transferred, is a complicated process which must be undertaken in multiple stages.

705. The Commission considers that the growth driver for these projects does not sufficiently demonstrate that the additional switchgear cells will be required by the end of the test period, when the proposed projects are forecast to be complete. However, the Commission accepts EDTI's evidence that these projects require several years to design, plan, construct and complete. Therefore, the Commission finds it is reasonable for these projects to begin in advance of the need for additional cells. It follows that it is not unreasonable that costs would be incurred in years prior to the switchgears coming into service.

706. With regard to the arc flash risk and the high fault levels, the Commission has weighed the evidence provided in the Quanta network study and SEAS reports, which support the need for additional switchgears at Rosssdale and Victoria substations, and finds that EDTI has sufficiently demonstrated that the additional switchgears are required from a technical standpoint. Accordingly, the Commission accepts that the projects will be required in order to address the issues presented by EDTI.

707. The timing of these projects appears to be, in part, driven by the Quanta network study which provided a timeline by which to reconfigure the downtown network. In that timeline, the Rosssdale switchgear was required to be completed in 2015 and the Victoria switchgear was required to be completed in 2016. EDTI did not propose to complete the projects according to the timeline provided in the Quanta network study. In testimony, EDTI indicated that it will proceed with these transmission projects, regardless of whether the distribution network reconfiguration project is completed.

708. The Commission has reviewed the proposed schedule for these projects. Both projects are large and complex, and are proposed to be completed in 2017. Of concern is that the Rosssdale project is currently behind schedule, which was confirmed by EDTI in the oral hearing. In response to questioning by Commission counsel on the timing of this project, EDTI's witness advised that EDTI could meet the scope of the Rosssdale project, but limited his response to the scope of work for 2015.⁶¹² In testimony, the EDTI witness confirmed that transfer of land from the City of Edmonton for the Rosssdale expansion was in negotiations but no timeline for the expected completion of the negotiations and subsequent transfer of the required land was provided.⁶¹³ The Commission notes that the modifications to the Rosssdale substation associated with this project are currently under consideration in Proceeding 20581.⁶¹⁴

709. With respect to the Victoria switchgear, the witness confirmed that there were no issues with project timing.⁶¹⁵ However, the Quanta witness confirmed that these projects should be

⁶¹² Transcript, Volume 3, pages 479-480.

⁶¹³ Transcript, Volume 3, page 531.

⁶¹⁴ Proceeding 20581, EPCOR Distribution and Transmission Inc., Rosssdale Substation Building Expansion, submitted June 30, 2015. This proceeding has currently scheduled an oral hearing for Wednesday, December 9, 2015.

⁶¹⁵ Transcript Volume 3, page 481.

synchronized as one cannot be implemented without the other. The Commission considers that the evidence on the record is that the projects must be completed in sync and that the Rossdale project is currently delayed.

710. There is inadequate evidence on the record to support that the addition of an MV switchgear at the Rossdale substation will proceed as scheduled given the delays to date. Given the evidence regarding the relationship between the Rossdale project and the Victoria project, the Commission concludes that completion of the Victoria project will be similarly delayed.

711. Accordingly, the Commission denies the forecast capital additions for these projects for the purposes of determining EDTI's revenue requirement in the test period. The Commission directs EDTI to remove the forecast capital additions and related costs with respect to the Rossdale and Victoria MV switchgear addition projects from its forecast 2015-2017 revenue requirement, in the compliance filing to this decision.

10.5.12 Life cycle replacement of 72-kV transmission cable splices, terminations, and cable sections (reference 9.2.3.1)

712. This ongoing life cycle replacement program consists of dismantling and replacing 72-kV underground OFPT transmission cable sections (also referred to as high pressure fluid filled (HPFF) cables), cable splice connections and/or terminations. EDTI has 91 km of underground 72-kV OFPT transmission cables, with the average age of the cables being 44 years.⁶¹⁶ In the long term, EDTI indicated it intends to replace the OFPT cables with XLPE cables.⁶¹⁷ In the test period, EDTI intended to make like-for-like replacements to cable sections, splice connections and/or terminations based on insulation condition which is approximated from DGA, partial discharge and cable paper insulation testing.⁶¹⁸

713. This project was referenced in Table 9.2.3.6-1 in the application as a project that is supported by the SEAS.⁶¹⁹ As discussed in Section 10.4.2 above, as part of the SEAS study, Quanta was engaged to assess the condition of EDTI's OFPT transmission cables, assess their remaining life, and make recommendations on the development of EDTI's transmission infrastructure to meet current and future operating and load carrying requirements of the system.⁶²⁰

714. In the executive summary of the SEAS report, Quanta stated that its review had not produced any findings of critical deterioration that would be indicative of imminent cable failure.⁶²¹ However, because the lead time for a new transmission underground circuit is three to four years, Quanta suggested that EDTI initiate the circuits' replacement program as soon as practicable.⁶²²

715. Quanta concluded in the SEAS report that the DGA results show levels of hydrogen that are elevated relative to industry standards and in general, the hydrogen levels appear to be rising, which is consistent with other utilities with HPFF cables of a similar vintage and system design.

⁶¹⁶ Exhibit 0003.00.EDTI-3539, application, paragraphs 2386-2387, PDF page 800 of 900.

⁶¹⁷ Transcript, Volume 3, page 613.

⁶¹⁸ Exhibit 0003.00.EDTI-3539, application, paragraph 2402, PDF page 804 of 900.

⁶¹⁹ Exhibit 0003.00.EDTI-3539, application, Table 9.2.3.6-1, PDF page 840 of 900.

⁶²⁰ Exhibit 0003.00.EDTI-3539, application, paragraph 2388, PDF page 800 of 900.

⁶²¹ Exhibit 0052.00.EDTI-3539, PDF page 6 of 194.

⁶²² Exhibit 0052.00.EDTI-3539, PDF page 6 of 194.

However, the methane and acetylene values are relatively low for cables of this age and design. Quanta recommended that all circuits be tested for the presence of partial discharges which would provide a second opinion to DGA on the need to replace joints. Quanta also recommended that EDTI continue to carry out regular DGA sampling and that EDTI conduct fluid flushing and filtering to improve the quality of the pipe fluid in circuits displaying elevated hydrogen levels.⁶²³

716. EDTI completed the following actions in the last few years to address the hydrogen gas content in insulating oil in its 72-kV OFPT transmission cables:

- In 2010, EDTI degasified the oil in the cable pothead termination and a portion of the transmission circuit 72RS5 and in the cable potheads located at Jasper substation relating to circuits 72JW19 and 72JM18.
- In 2012, EDTI degasified approximately 20,000 litres of transmission cable oil (which is approximately 30 per cent of the oil volume in these circuits) relating to 72-kV circuits 72RG7 and 72RS5.
- In 2013, EDTI degasified approximately 49,000 litres of transmission cable oil (the total oil volume of this circuit) relating to 72-kV circuit 72RS5.

717. In addition to the DGA and degasification, EDTI stated it carries out sampling of cable insulation papers when completing projects related to reconstruction of cable splices, installation of cable oil barrier splices or underground transmission cable diversions. The cable insulation paper is analyzed and that analysis is used, with the DGA, to assess the condition of EDTI's OFPT cables.⁶²⁴

718. EDTI confirmed that in the span of 15 to 25 years, it intends to replace the entire 72-kV OFPT cable system however, this full replacement is subject to direction and approval from the AESO.⁶²⁵ Quanta's witness confirmed that utilities with a mix of cables similar to that of EDTI would have a similar replacement schedule, meaning, if an entire circuit is replaced, it will be with XLPE cable. However, if only a section is replaced, it will be on a like-for-like basis (as replacing a small section with XLPE is not possible). Until such time as the full circuit is replaced, the utility must still inspect the cable, respond to alarms and maintain the cable and the associated dynamic components, such as pumping plants.⁶²⁶ The Quanta witness noted that it is not uncommon to find OFPT cables operating 60 years after they were installed and still providing reliable service.⁶²⁷ Quanta's witness also explored temporary or mobile facilities that could be used during the transition of an underground cable system from 72 kV to 240 kV and indicated that some utilities will install new permanent facilities that are going to operate at 240 kV. However, until such time as the utility is ready to operate at that voltage, the circuits are operated at 72 kV. This measure can minimize the time required to make the conversion.⁶²⁸ EDTI confirmed that one example of such a methodology, which can be found in the current test period, is the new cable installed as part of the south central transmission reinforcement project which will be operated initially at 72 kV, even though the cable is a 240-kV cable.⁶²⁹

⁶²³ Exhibit 0052.00.EDTI-3539, PDF pages 33-34 of 194.

⁶²⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 8-10, PDF pages 269-270 of 433.

⁶²⁵ Transcript, Volume 6, page 914.

⁶²⁶ Transcript, Volume 6, pages 1144-1147 and 1151.

⁶²⁷ Transcript, Volume 6, page 1145.

⁶²⁸ Transcript, Volume 6, page 1189.

⁶²⁹ Transcript, Volume 6, page 1191.

719. Consistent with historic practice, EDTI intends to replace one 72-kV splice connection and one 72-kV termination in each of the test years. No cable sections are proposed to be replaced in the test period.⁶³⁰ The replacements are selected on the basis of measured concentrations of hydrogen and other gases in the cable insulating oil (when they exceed levels recommended in Institute of Electrical and Electronics Engineers (IEEE) 1406-1998 and Electric Power Research Institute (EPRI) TR 1000275), analysis of testing results of the cable insulating paper, analysis of partial discharge testing results, inspection results, analysis of soil samples,⁶³¹ operating performance of the cables, criticality of the transmission cable and the age of cables.⁶³² High levels of gases usually indicate degradation of the cable insulation system or that arcing has taken place in the cable paper insulation, which are a precursor to cable fault conditions. OFPT cable faults typically require lengthy repair outage times and can pose a risk to the environment and the safety of EDTI personnel and the public.

720. EDTI also uses the cable AHI total health, total risk and total rating information when selecting cable system assets to be replaced.⁶³³ The AHI is further described in the SEAS Underground Transmission Assessment.⁶³⁴ EDTI noted that while the DGA has limited weight in the overall AHI, the results of the DGA alone can cause a cable to be replaced.⁶³⁵

721. This program does not have a defined scope of work and is considered a bucket project. EDTI indicated that, for projects that do not have a defined scope of work, such as this, projects that get delayed from one year to another do not affect the total forecast capital additions of that program in any given year.⁶³⁶

722. The forecast capital additions for this project are \$0.80 million in 2015, \$0.82 million in 2016 and \$0.85 million in 2017.⁶³⁷ EDTI intends to use internal resources to carry the forecast 72-kV OFPT transmission cable termination replacement and to carry out all 72-kV OFPT cable splice replacement-related project work like cable oil freezing, cable pipe work and worksite related preparations. A specialized contractor generally will perform work for which EDTI's staff is not currently trained.⁶³⁸ EDTI has initiated a training program for internal resources to carry out some 72-kV cable work in 2013 and anticipates seeing savings associated with performing the work internally starting 2018.⁶³⁹

723. EDTI evaluated three alternatives for dealing with the life cycle replacement of its 72-kV underground transmission cable splices and terminations: (1) emergency repair and replacement only, (2) replace the existing 72-kV underground cables on a complete circuit basis, and (3) life cycle condition based replacement program. The alternative of "doing nothing" was not considered as the test results show that the cable insulation system is degrading and could lead to cable fault conditions that require lengthy repair outage times, which in turn reduces reliability and is not an acceptable solution. The first alternative was rejected on the basis that operating equipment to failure is unacceptable given the associated operating, environmental and safety

⁶³⁰ Exhibit 0030.00.EDTI-3539, Table T-CBC-16-3, PDF page 272.

⁶³¹ Exhibit 0030.00.EDTI-3539, paragraph 17, PDF pages 272-273.

⁶³² Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 16, PDF page 272 of 433.

⁶³³ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-091(e), PDF page 303.

⁶³⁴ Exhibit 0052.00.EDTI-3539, Appendix 1, PDF page 172.

⁶³⁵ Exhibit 3539-X0180.

⁶³⁶ Transcript, Volume 1, page 129.

⁶³⁷ Exhibit 3539-X0128.01.

⁶³⁸ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-038(a), PDF pages 139-140.

⁶³⁹ Exhibit 3539-X0193, PDF pages 244-245.

risks. Also, emergency repair and replacement of failed underground cable splices and terminations typically costs more than replacing the equipment on a planned life cycle replacement basis. The second alternative proposed was to replace the entire circuit with XLPE insulated cable. Under this alternative, EDTI anticipated operating expenditure reductions related to carrying out DGA, cathodic protection inspection, cable oil degasification, refurbishing cable pipe protective coatings and general cable system maintenance. However, EDTI rejected this alternative on the basis that the NPV is higher than for life-cycle condition based replacement. EDTI proposed that this alternative will minimize the level of capital expenditure required to achieve the continued safe and reliable operation of the 72-kV underground OFPT transmission cable system.⁶⁴⁰

724. The UCA did not address this program in its evidence, argument or reply.⁶⁴¹

Commission findings

725. The Commission continues to be concerned with rising transmission life cycle replacement and maintenance costs, in light of longer term plans to completely replace an asset class. However, the Commission acknowledges that EDTI's assets must be maintained at a level whereby it can continue to provide safe, reliable and economic electricity transmission service. In the case of the proposed 72-kV underground cable splice and termination replacements project, the Commission considers that the evidence on the record is that OFPT cables, such as that in use in EDTI's system, can be reliable for 60 years or more if properly maintained. EDTI has pointed out that its 72-kV underground cable system is on average, 44 years of age with the oldest circuit being 57 years old. As the 72-kV cable system approaches the end of its useful life, EDTI anticipates that it will replace the entire system with new XLPE cables, in 15 to 25 years following direction from the AESO. The Commission considers that the complete replacement of the OFPT cables contemplated in this plan is not sufficiently near-term to negate the life cycle replacements required on some cables or associated cable system equipment. Therefore, the Commission finds that the life cycle replacement of OFPT cable splices, terminations and sections on a like-for-like basis is reasonable.

726. The cost forecasts for the 72-kV cable splice and terminations replacements program are determined using historical costs and the forecast replacement schedule is based on historical information. Although the Commission has concerns about forecasting accuracy for projects of this nature, it finds that the use of a three-year average is a reasonable basis on which to forecast costs for the purpose of establishing a revenue requirement. Therefore, the Commission approves the forecast capital additions for the life cycle replacement of 72-kV transmission cable splices, terminations and cable sections program for the purposes of determining EDTI's revenue requirement in the test period.

10.5.13 Life cycle replacement of 240-kV cable sections (reference 9.2.3.2)

727. This ongoing life cycle replacement program consists of dismantling and replacing 240-kV underground OFPT transmission cable sections, cable splice connections and/or terminations. EDTI has 9.3 km of underground 240-kV OFPT transmission cables, consisting of two separate transmission circuits (designated 240BA2 and 240BA3). These circuits were constructed between 1978 and 1980.⁶⁴² In the previous test period, EDTI began work to replace

⁶⁴⁰ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 276-279 of 433.

⁶⁴¹ Exhibits 3539-X0051, 3539-X0192 and 3539-X0196.

⁶⁴² Exhibit 0003.00.EDTI-3539, application, paragraphs 2418 and 2420, PDF page 809 of 900.

cable terminations, cable risers, trifurcator and approximately 150 metres of transmission cable on circuit 240BA3.⁶⁴³ The work was completed and the circuit returned to service at the end of 2014.⁶⁴⁴ In the current test period, EDTI proposed a like-for-like replacement of a 150 metre portion of the 240BA2 circuit near the Argyll substation (including pipe, cable and accessories), the cable terminations, cable risers, and trifurcator.⁶⁴⁵

728. This project was referenced in Table 9.2.3.6-1 in the application as a project that is supported by the SEAS study and Quanta reports.⁶⁴⁶ As discussed in Section 10.4.2 above, as part of the SEAS study, Quanta was engaged to assess the condition of EDTI's OFPT transmission cables, assess their remaining lives, and make recommendations on how the development of EDTI's transmission infrastructure should proceed to meet current and future operating and load carrying requirements of the system.⁶⁴⁷ In the SEAS report, Quanta evaluated the 240BA2 circuit, noting no major past failures but finding concerns or "action" levels of hydrogen in six of 12 samples and acceptable levels for all other gases.⁶⁴⁸ Quanta noted that EDTI intended to replace the 240BA2 cable pipe, riser and accessories at the Argyll station and that ideally, partial discharge testing would be performed in advance as an additional input to the decision process.⁶⁴⁹ Quanta recommended that EDTI flush all fluid from the circuit through a filter and degasser while monitoring DGA levels, until the hydrogen concentrations have been reduced to less than 10,000 parts per million (ppm) at manholes and 5,000 ppm at terminal ends. Then following degassing, the DGA should be monitored every six months and if the trending indicates reappearing of gasses at an "unusual" rate, the circuit or part of it should be replaced. Quanta also recommended that Kraft paper radial tests be done and partial discharge and tan delta tests be done to establish a baseline for future circuit evaluations and to help verify the length of section that should be replaced.⁶⁵⁰

729. EDTI confirmed that it had implemented Quanta's recommendations with the exception of tan delta, which EDTI did not intend to perform as EDTI prefers to only perform partial discharges.⁶⁵¹ Quanta's witness indicated that the tan delta test technique was initially recommended; however, subsequently, EDTI chose to adopt an alternative technique which is not appropriate for tan delta measurements and therefore EDTI proposed that its technique is valid.⁶⁵²

730. EDTI completed the following maintenance actions, while simultaneously inspecting the cable, paper insulation and cable oil, in the last few years to address the high hydrogen gas content in the insulating oil in its OFPT cables:

- In 2001 and 2002, EDTI degasified the oil in the two 240-kV OFPT cables.

⁶⁴³ Exhibit 0003.00.EDTI-3539, application, paragraphs 2428-2429, PDF page 811 of 900.

⁶⁴⁴ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-039(a), PDF page 144.

⁶⁴⁵ Exhibit 0003.00.EDTI-3539, application, paragraph 2430, PDF page 811 of 900.

⁶⁴⁶ Exhibit 0003.00.EDTI-3539, application, Table 9.2.3.6-1, PDF page 840 of 900.

⁶⁴⁷ Exhibit 0003.00.EDTI-3539, application, paragraph 2388, PDF page 800 of 900.

⁶⁴⁸ Exhibit 0052.00.EDTI-3539, PDF pages 140-141. Levels were assigned a rating of "concern," "action" or "acceptable" per the EPRI guideline.

⁶⁴⁹ Exhibit 0052.00.EDTI-3539, PDF page 142.

⁶⁵⁰ Exhibit 0052.00.EDTI-3539, Section 7.18.5, PDF page 147.

⁶⁵¹ Per EDTI's testimony at Transcript, Volume 6, page 1152, EDTI has performed "partial discharge, and we've degassed the circuits."

⁶⁵² Transcript, Volume 6, page 1153.

- In 2003, EDTI replaced components of the cable terminations at the Argyll Terminal end of EDTI's two 240-kV cables.
- In 2004, EDTI carried out the life cycle replacement of two cable splices on transmission circuit 240BA2.
- In 2010, EDTI degasified approximately one third of the cable oil volumes in the two 240-kV underground circuit.
- In 2012, EDTI carried out further degasification of the oil in the two transmission circuits, flushing approximately 2,700 and 1,450 gallons of oil in 240BA2 and 240BA3 respectively at the Argyll Terminal end of the cable and 8,000 and 5,000 gallons of oil in 240BA2 and 240BA3, respectively, at the Bellamy Terminal end of the cables.⁶⁵³

731. EDTI reiterated that the cable oil degasification does not resolve the source of the dissolved gases and the dissolved gases tend to regenerate over time.⁶⁵⁴

732. Since 2001, EDTI carried out DGA analysis on its 240-kV OFPT transmission cables.⁶⁵⁵ Cable section, termination or splice connection replacements are selected on the basis of measured concentrations of hydrogen and other gases in the cable insulating oil, when they exceed levels recommended in IEEE 1406-1998 and EPRI TR 1000275. Cable circuits 240BA2 and 240BA3, being of the same manufacture and vintage and having been installed by the same contractor, has caused EDTI to expect to observe similar cable conditions to those found on 240BA3. Electric tracking in the paper insulation is indicative of high voltage stresses in the cable termination and can be a precursor to cable fault conditions.⁶⁵⁶ Other factors that EDTI considered when selecting underground transmission cable splices, terminations and cable sections for life cycle replacements were inspection results, cable paper insulating testing, operating performance of the cables, criticality of the transmission cable, and cable age.⁶⁵⁷ OFPT cable faults typically require lengthy repair outage times and can pose a risk to the environment and the safety of EDTI personnel and the public.⁶⁵⁸

733. EDTI also uses the cable AHI total health, total risk and total rating information when selecting cable system assets to be replaced.⁶⁵⁹ The information in the AHI for transmission circuit 240BA2 is provided in the SEAS Underground Transmission System Assessment.⁶⁶⁰ EDTI noted that while the DGA has limited weight in the overall AHI, the results of the DGA alone can cause a cable to be replaced.⁶⁶¹

734. Although EDTI experienced large cost variances in its 2014 work on 240BA3, it did not anticipate that these higher contractor costs would occur in the current test period and therefore, did not adjust the project forecast to account for the increase seen in the last test period. EDTI's witness explained that there is uncertainty regarding the workload of the specialized contractors

⁶⁵³ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 284-285 of 433.

⁶⁵⁴ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 17, PDF page 287 of 433.

⁶⁵⁵ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 4, PDF page 281 of 433.

⁶⁵⁶ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraphs 20-21, PDF page 288 of 433.

⁶⁵⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 24, PDF page 289 of 433.

⁶⁵⁸ Exhibit 0030.00.EDTI-3539, Appendix E-1, paragraph 10, PDF page 284 of 433.

⁶⁵⁹ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-091(e), PDF page 303.

⁶⁶⁰ Exhibit 0052.00.EDTI-3539, Section 7.18.3, PDF page 146.

⁶⁶¹ Exhibit 3539-X0180.

as far out as 2016 and 2017 and that the market was constrained in 2014. This is why there was an increase in contractor costs. EDTI stated that it was “comfortable with these costs.”⁶⁶² EDTI argued that the ultimate solution to the small number of specialized contractors who can work on 240-kV OFPT cables is to move away from that cable technology so that EDTI will not be subject to the ups and downs of the niche market for this work.⁶⁶³

735. EDTI stated that it intends to begin working on the project in 2016 but forecasts adding the project to rate base in 2017. The forecast capital addition for this project is \$6.05 million.⁶⁶⁴ The capital additions for the current test period are based on EDTI’s forecast costs for the 240BA3 capital project from the previous GTA.⁶⁶⁵ EDTI explained that the work is forecast to be carried out by specialized contractors and EDTI has not explored any opportunities to train its internal workforce to carry out 240-kV OFPT cable splice replacement projects because the work involved is more complex than for the 72-kV cable for which they are trained. EDTI noted that the training being completed by internal resources will allow them to carry out all cable oil freezing, cable pipe work and worksite-related preparation activities on future 240-kV OFPT transmission cable replacement projects.⁶⁶⁶

736. EDTI evaluated three alternatives for dealing with the life cycle replacement of its 240-kV underground transmission cable sections, splices and terminations: (1) emergency repair and replacement only, (2) replacing the existing 240-kV OFPT underground cable (i.e., transmission circuit 240BA2) on a complete circuit basis, and (3) a life cycle condition based replacement program. The alternative of “doing nothing” was not considered. The first alternative was rejected on the basis that operating equipment to failure is unacceptable given the associated operating, environmental and safety risks. Also, the emergency repair and replacement of failed underground cable sections, splices and terminations typically costs more than equipment replacement on a planned life cycle replacement basis. EDTI rejected the second alternative on the basis that the NPV is higher than that of the third alternative. Under the third alternative of proceeding with a condition based replacement program, EDTI expected operating expenditure reductions related to an expected reduction in the frequency and volume of cable oil required to be degasified, based on reduced concentrations of dissolved gasses in cable oil. This alternative was selected on the basis that it will minimize the level of capital expenditure required to achieve the continued safe and reliable operation of the 240-kV underground OFPT transmission cable system.⁶⁶⁷

737. In the evidence submitted by the UCA, Mr. Bell asserted that there is no detailed quantitative analysis of the impact of not pursuing this project, from a service quality or safety perspective. Additionally, Mr. Bell stated that EDTI has known about the high levels of dissolved hydrogen since at least 2006. In Mr. Bell’s view, despite EDTI’s assertion that running to failure is not an option, there is insufficient evidence as to why the project could not be delayed one forecast test period.⁶⁶⁸ Mr. Bell recommended that the Commission find that EDTI

⁶⁶² Transcript, Volume 3, page 487.

⁶⁶³ Exhibit 3539-X0193, PDF pages 224-225.

⁶⁶⁴ Exhibit 3539-X0128.01.

⁶⁶⁵ Exhibit 0003.00.EDTI-3539, application, paragraph 2444, PDF page 815 of 900.

⁶⁶⁶ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-039(b), PDF pages 144-146.

⁶⁶⁷ Exhibit 0030.00.EDTI-3539, Appendix E-1, PDF pages 291-294 of 433.

⁶⁶⁸ Exhibit 3539-X0051, pages 14-16, Q&A 25.

has not adequately demonstrated why the 240-kV cable sections life cycle replacement project is required in the test period and that the forecast capital additions be denied.⁶⁶⁹

738. In its rebuttal, EDTI cautioned that there would be a substantially increased probability of catastrophic failure of transmission cable 240BA2 if this life cycle replacement project was deferred to the next GTA. In EDTI's submission, Mr. Bell has not provided evidence or engineering analysis that contradicts EDTI's evidence or EDTI's expert opinion in any way.⁶⁷⁰

739. In argument, the UCA continued to ask "why now?" with regards to the need for this project to be completed in this test period. In examining the hydrogen concentration levels since 2001, the UCA noted that, if one draws a line from 2006 on, the level of gas is fairly flat and the increase in gas levels [hydrogen] appears to have occurred in 2004 to 2006.⁶⁷¹ The UCA argued that it is not suggesting that the projects should not be done, if truly needed, but rather that there is insufficient evidence to include the costs in rates for this test period. As such, the proposed capital additions should be denied.⁶⁷²

740. EDTI argued that it had presented ample evidence that the situation with the 240BA2 circuit is critical and that this project cannot be delayed to the next GTA. EDTI also noted that its practices with respect to OFPT cables were endorsed by Quanta as being consistent with industry practices and therefore, Mr. Bell's position that this project can be delayed should be rejected.⁶⁷³

741. In reply, the UCA asked "if the level of discharge has been constant for a number of years, then how fast is the problem growing?" The UCA argued that there is no evidence to support that 240BA2 will behave identically to 240BA3 or why the project must be funded now.⁶⁷⁴ EDTI's reply emphasized that the dissolved hydrogen gas cable oil has largely remained at 2006 levels due to the ongoing maintenance efforts EDTI has undertaken to address the problem.⁶⁷⁵

Commission findings

742. EDTI has not provided evidence outside of dissolved gas levels, which can be temporarily lowered through maintenance practices, in support of its contention that the 240BA3 circuit should be replaced. Although EDTI performed one partial discharge test, as recommended by Quanta, to demonstrate that the risk of catastrophic failure has increased and has become unacceptable, the results of the test were not provided on the record of the proceeding.

743. EDTI stated that the dissolved gas levels in the cable oil have been relatively stable since 2006 due to its maintenance program. There is insufficient evidence to suggest that this maintenance program will not adequately provide for the safe and reliable operation of this cable for the remainder of the test period. In addition the cable is some 35 years old and the Quanta witness confirmed that cables of this type can be expected to last for up to 60 years. Accordingly, the Commission denies the forecast capital additions for this project in the test period for the purposes of determining EDTI's revenue requirement. The Commission directs EDTI in its

⁶⁶⁹ Exhibit 3539-X0051, page 17, Q&A 27.

⁶⁷⁰ Exhibit 3539-X0071, Q&A 55.

⁶⁷¹ Exhibit 3539-X0051, PDF page 16.

⁶⁷² Exhibit 3539-X0051, PDF page 18.

⁶⁷³ Exhibit 3539-X0193, PDF page 230.

⁶⁷⁴ Exhibit 3539-X0196, PDF page 16.

⁶⁷⁵ Exhibit 3539-X0197, PDF page 55.

compliance filing, to remove all costs associated with this project from the 2015-2017 revenue requirement.

10.6 Information requirements for future applications respecting capital projects

744. In evidence filed on behalf of the UCA, Mr. Bell expressed concern that EDTI had not considered options to defer certain projects to the future, nor had EDTI provided evidence supporting why those projects must proceed now.⁶⁷⁶

745. Mr. Bell pointed to Decision 2013-435⁶⁷⁷ and the 10 criteria⁶⁷⁸ for project assessment under capital tracker treatment. Mr. Bell stated that, while several of the criteria were already subsumed in information provided in business cases under cost of service regulation, significant benefit could be gained if the Commission were to direct EDTI in future GTAs to include the following:

- a demonstration that a deterioration in service quality and safety would result if a proposed capital expenditure did not occur
- a demonstration of why the timing of the proposed capital expenditure is optimal and could not be deferred
- a comparison of similar projects including variance explanations related to both units and costs-per-unit

746. Mr. Bell submitted that this information would assist parties, in the future, in understanding why EDTI may be choosing to proceed with certain projects rather than deferring them to future test periods.

747. In its rebuttal, EDTI submitted that Mr. Bell's request was unnecessary as comprehensive information respecting its capital project forecasts was already available in EDTI's business cases as set out in the MFR and PIRs, as required under cost of service regulation. EDTI described the specific detail included in its MFR and PIR documents in its rebuttal evidence and concluded that each of the three criteria identified by Mr. Bell was already being provided by EDTI.⁶⁷⁹

748. EDTI argued that it has provided detailed and comprehensive information in its application, including within each business case, "detailed analysis and evaluation of each project, including an analysis of the cost, need and alternatives of the project, which includes consideration of impacts on safety, service quality, and project timing, all of which provide sufficient justification of proposed capital projects."⁶⁸⁰

749. EDTI concluded that it had submitted information that satisfied the Commission's MFRs and previous directions and provided an appropriate level of quantitative and qualitative information. EDTI also pointed to the hearing process as having provided a further opportunity

⁶⁷⁶ Exhibit 3539-X0051, UCA evidence, Q&A 19-24, pages 10-14.

⁶⁷⁷ Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

⁶⁷⁸ Decision 2013-435, paragraph 1092, bullets (a) through (j).

⁶⁷⁹ Exhibit 3539-X0071, EDTI rebuttal, Section 7, Q&A 41-43, PDF pages 50-56.

⁶⁸⁰ Exhibit 3539-X0193, EDTI final argument, paragraph 598.

for parties to seek information, and that EDTI had responded thoroughly and transparently to any such requests.

750. EDTI stated that Mr. Bell's recommendations for future applications are unnecessary and should be rejected.⁶⁸¹

751. In reply, the UCA responded that the MFR should not be used as a reason to not provide the additional information, which the UCA considered would be relevant to the testing of an application and useful to the Commission.⁶⁸²

Commission findings

752. The recommendations of Mr. Bell would increase capital project filing requirements beyond what is currently required of utilities, outside of the capital tracker proceedings. As discussed in Decision 2014-269, EDTI has been provided multiple Commission directions⁶⁸³ as to what information is considered relevant and necessary for the purposes of examining capital within a GTA and with which EDTI must remain compliant. These information requirements are in addition to what is already mandatory under the MFRs found on the Commission's website.⁶⁸⁴

753. Ultimately, the burden of demonstrating to the Commission that its forecast costs are reasonable rests with the utility. Additionally, it is open to the Commission and interveners to request additional information that is believed to be required in IRs and through cross-examination.

754. The Commission is concerned that imposing the additional requirements recommended of Mr. Bell in this case could further add to the volume and complexity of EDTI's GTA proceedings. The Commission is not convinced at this time that the adoption of distribution function capital tracker – type criteria is necessary, given the volume of information on the record of this GTA and the ability of parties to obtain additional specific capital information, should it be required.

10.7 Working capital and balances in reserve and deferral accounts

755. EDTI provided historical and forecast costs related to its working capital in Section 10 of its application. Information from Table 10.0-1 has been reproduced in the following table:

⁶⁸¹ Exhibit 3539-X0193, EDTI final argument, paragraph 612.

⁶⁸² Exhibit 3539-X0196, UCA reply argument, pages 15-16.

⁶⁸³ Decision 2006-054, directions 12 and 27; Direction 2004-067, direction at page 105; Decision 2010-505, direction at paragraph 278.

⁶⁸⁴ Minimum Filing Requirements – Phase I, May 8, 2006.

Table 38. Working capital requirements 2013-2017

Description of working capital component	2013 Decision 2014-269	2013 actual	2014 Decision 2014-269	2014 actual	2015 forecast	2016 forecast	2017 forecast
	(\$ million)						
Operating expenses	1.17	0.53	1.31	1.11	1.22	1.27	1.34
Depreciation	2.06	2.07	2.52	2.56	2.72	2.90	3.07
Debt costs	(5.61)	(5.47)	(7.08)	(7.19)	(7.88)	(8.45)	(8.85)
Common equity	1.83	1.48	2.39	3.33	2.41	2.48	2.65
Lead/lag subtotal	(0.54)	(1.39)	(0.86)	(0.19)	(1.53)	(1.80)	(1.79)
Goods and Services Tax (GST)	(0.01)	(0.01)	(0.00)	(0.00)	(0.01)	(0.02)	(0.01)
Subtotal	(0.55)	(1.40)	(0.87)	(0.19)	(1.54)	(1.82)	(1.80)
Mid-year inventory	0.70	0.69	0.71	0.69	0.67	0.67	0.67
Mid-year deferred costs and reserve balances	0.11	0.52	0.40	1.99	1.84	0.36	0.32
Total working capital	0.27	(0.19)	0.24	2.48	0.96	(0.79)	(0.81)
Over (under) 2013 and 2014 decision to actuals or forecast \$		(0.08)		2.24	0.72		
Over (under) 2013 and 2014 actuals and forecast \$				2.67	(1.52)	(1.75)	(0.02)

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 11-1.

756. EDTI stated that the calculation of forecast working capital for operating expenses, depreciation expense, debt return and common equity is based on lead/lag days of revenue and expenses. The working capital calculation for GST is based on the impact GST has on revenue and expenses. The calculation of forecast working capital for materials and supply inventory and unamortized deferred costs is based on the mid-year estimated balances for these accounts.⁶⁸⁵

757. The UCA submitted that it had concerns with respect to how EDTI had included depreciation and equity return cash flows in its working capital. The UCA stated that the inclusion of depreciation and equity return in working capital dates back to the late 1980s, when Public Utilities Board (PUB) Decision E91095⁶⁸⁶ summarized the rationale for including depreciation and equity return in working capital. In the UCA's view, the intent of the PUB with respect to depreciation was to match cash flows, and the intent with respect to equity return was to maintain the mid-year principle.⁶⁸⁷

758. The UCA submitted that there are two large cash flows missing from EDTI's working capital analysis: the timing of the issuance of long-term debt and the timing of capital additions. The UCA argued that, "To the extent the issuance of Long Term Debt and the timing of Capital Additions are not at an average of mid-year, the matching of cash flows and preservation of the mid-year convention can be materially impacted. The exclusion of the timing of Capital Additions and the timing of the issuance of Long Term Debt from an NWC [necessary working capital] analysis has the effect of rendering the analysis incomplete."⁶⁸⁸

⁶⁸⁵ Exhibit 0003.00.EDTI-3539, application, paragraphs 2680-2682, PDF page 877 of 900.

⁶⁸⁶ Decision E91095: Alberta Power Limited, General Rate Application for the 1991 test year, File 910083 2050 0005 0002, December 13, 1991, pages 164-165 and 169-170.

⁶⁸⁷ Exhibit 3539-X0192, UCA argument, paragraphs 69-71, PDF pages 18-20 of 22.

⁶⁸⁸ Exhibit 3539-X0192, UCA argument, paragraph 72, PDF page 20 of 22.

759. With respect to capital additions, the UCA submitted that EDTI has not provided any evidence that the timing of capital additions or expenditures is at or near mid-year, on average. Without this evidence, it is impossible to properly test the assumptions underpinning the inclusion of depreciation or equity return in working capital, or to determine if additional adjustments to working capital are required to properly match cash flows.⁶⁸⁹

760. With respect to issuing long-term debt, the UCA stated that EDTI has a pattern of issuing long-term debt at the end of the year. For the 12 issues of long-term debt, between 1999 and 2014, 10 were late in the year. This pattern is not consistent with the mid-year convention and the UCA submitted that EDTI routinely benefits from the fact that it issues debt later in the year, when recovering the mid-year cost of debt in rates.⁶⁹⁰

761. Additionally, the UCA took issue with EDTI including notes payable in its embedded cost of debt. In examining the EDTI financial statements, it appeared that notes payable are short-term notes payable to EPCOR and would result in the cost of short-term debt being reflected in the embedded cost of debt.⁶⁹¹

762. The UCA recommended that, in future rate applications, EDTI should be required to provide total capital additions and expenditures by month to test the matching of cash flows and the validity of the mid-year assumption. In addition, EDTI should be required to demonstrate why issuing debt at mid-year is prudent in light of the timing of cash flows. The UCA is of the view that this could be done by providing monthly short-term debt balances for the prior three years of actual results.⁶⁹²

763. EDTI responded to the UCA that its inclusion of depreciation and return in its working capital calculation is reasonable and appropriate and reflects the long-standing practice of the Commission. The method used by EDTI to include depreciation and return in the working capital calculation is consistent with the Commission's MFR schedules and with the methods used by both AltaLink and ATCO.⁶⁹³

764. In its response to EDTI-UCA-2015FEB06-003(c), EDTI stated:

The inclusion of depreciation and return on common equity in the working capital calculation provides utilities the ability to recover carrying costs as there is a timing difference when assets are constructed and put into service and the length of time required for a utility to recover its capital related costs. The AUC has provided a mechanism for utilities to recover these costs by including depreciation and return on equity in the working capital calculations in the MFR Schedules the EUB published in Bulletin 2006-25 Consensus Documents for minimum filing requirements, specifically Schedules 11-2 for Transmission and 21-2 for Distribution.⁶⁹⁴

765. EDTI submitted that the rationale for including depreciation and return in the working capital calculation, as expressed in PUB Decision E91095,⁶⁹⁵ relies on the use of the mid-year

⁶⁸⁹ Exhibit 3539-X0192, UCA argument, paragraphs 79-80.

⁶⁹⁰ Exhibit 3539-X0192, UCA argument, paragraphs 73-74.

⁶⁹¹ Exhibit 3539-X0192, UCA argument, paragraph 77.

⁶⁹² Exhibit 3539-X0192, UCA argument, paragraph 81.

⁶⁹³ Transcript, Volume 1, page 148.

⁶⁹⁴ Exhibit 3539-X0034, EDTI-UCA-2015FEB06-003(c).

⁶⁹⁵ Decision E91095, page 164 and page 169.

convention and remains valid today. EDTI submitted that the PUB stated that it considered it appropriate to include depreciation and financial items in the lead/lag study as a means of matching all cash inflows with outflows and that the PUB indicated that this is consistent with the use of the mid-year convention. EDTI submitted that its method of calculating working capital is reasonable and appropriate and fully justified based on the evidence on the record.⁶⁹⁶

766. EDTI also stated that the UCA's request that EDTI provide monthly capital additions and expenditures is misguided. EDTI explained that it does not track monthly capital additions because it applies the mid-year convention, which assumes that all capital additions are spread evenly throughout the year. EDTI submitted that the mid-year convention is a reasonable assumption that has been consistently used by the Commission, its predecessors and other regulators across North America and cited Decision 2012-237⁶⁹⁷ as follows:

The mid-year rate base convention is the accepted method for approximating the cost of capital investments in the year, and for the purposes of calculating other capital related costs. The mid-year convention uses an arithmetical average of a utility's investments to account for capital related costs uniformly over the entire year, recognizing that assets are added to rate base throughout the year. It is commonly used in regulatory jurisdictions in North America.⁶⁹⁸

767. EDTI also pointed to Decision 2010-496,⁶⁹⁹ where the Commission states that the mid-year convention "has been the norm that has been applied in recognizing rate base transactions" and that its application "is consistent with the findings of the Court of Appeal in the Working Capital Appeal Decision." The "Working Capital Appeal Decision" is a reference to *Calgary (City) v. Alberta (Energy and Utilities Board)*, 2010 ABCA 94, in which the Alberta Court of Appeal held that the predecessor to the AUC did not err in law or jurisdiction by applying the mid-year convention, as opposed to the monthly average calculation, to the cost of gas in storage component of the calculation of necessary working capital.⁷⁰⁰

768. EDTI submitted that the UCA's supposition that the validity of the mid-year assumption needs to be tested is incorrect. The mid-year convention does not mean that all capital additions in every year are exactly evenly spread; but it is an assumption that is made by convention. Thus, it would not be surprising to find that, in a particular year for a particular utility, the capital additions were not exactly evenly spread across the year. Such a finding would not be reason to change the mid-year convention.⁷⁰¹

769. EDTI stated that the UCA has not provided any reason to change the mid-year convention and has not provided any other reasonable alternative. In addition, forecasting capital additions on a monthly basis would result in significant added complexity to the regulatory

⁶⁹⁶ Exhibit 3539-X0197, EDTI reply argument, paragraphs 173-174.

⁶⁹⁷ Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

⁶⁹⁸ Decision 2012-237, paragraph 101.

⁶⁹⁹ Decision 2010-496: ATCO Gas South, Removal of Carbon Related Assets from Utility Service, Proceeding 87, Application 1579086-1, October 19, 2010.

⁷⁰⁰ Exhibit 3539-X0197, EDTI reply argument, paragraph 181.

⁷⁰¹ Exhibit 3539-X0197, EDTI reply argument, paragraph 182.

process, with no corresponding benefit. Additionally, EDTI stated the UCA's request for information in future applications should be denied.⁷⁰²

770. EDTI stated that the UCA's rationale for seeking monthly short-term debt balances is also misguided. The monthly short-term debt balances would not assist in demonstrating the timing of the need for financing. EDTI acknowledged that, in a number of years, it had placed its debt issues closer to the end of the year as opposed to mid-year. However, the need for this was not driven by short-term debt balances but instead was to align EDTI's capital structure with what was approved by the Commission.⁷⁰³ Therefore, while short-term debt is one of the mechanisms EDTI uses to finance its operations, there is no indication that providing monthly short-term debt balances will assist in demonstrating the timing of the need for financing.⁷⁰⁴

771. EDTI submitted that it has taken steps to issue its debt at mid-year, to be more in line with what has been forecast. EDTI has been pro-active in obtaining Commission approvals related to debt issues. This is illustrated by Mr. Chaudhary, who explained at the hearing:

What we've done last year is we applied to the Commission to have our approvals for debt issuances for 2014 and 2015 approved in advance, and what that has done is it's afforded us the opportunity to place our debt in 2015 in line with a date that's been included in our 2015 forecast in our application.

We work with our EPCOR treasury group to, you know, determine the ideal time or the most appropriate time for us to issue our debt. And in my opinion, based on what we did last year, we're in a position to issue debt in a manner that's consistent with what we've included in our 2015 application.⁷⁰⁵

772. Given that the timing of debt issuances later in the year was not driven by short-term debt balances and given that EDTI has taken steps to issue its debt mid-year in a manner consistent with its forecasts, EDTI submitted that the UCA's request for short-term debt balances in future applications is unnecessary and should be denied.⁷⁰⁶

Commission findings

773. The UCA requested that in future rate applications, EDTI should be required to provide total capital additions and expenditures by month, in order to test the matching of cash flows and the validity of the mid-year convention. However, EDTI explained that it does not track monthly capital additions because it applies the mid-year convention and that forecasting capital additions on a monthly basis would result in additional complexity.

774. The Commission agrees with EDTI that the additional tracking proposed by the UCA would add unnecessary complexity. Consistent with Decision 2012-237, the Commission finds that it is a long-standing convention of the Commission and its predecessors to use the mid-year convention for capital additions and capital expenditures. The mid-year convention is a reasonable method to account for capital-related costs over the entire year, while recognizing that some assets are added to rate base prior to mid-year and some assets are added to rate base after

⁷⁰² Exhibit 3539-X0197, EDTI reply argument, paragraph 184.

⁷⁰³ Transcript, Volume 1, page 153.

⁷⁰⁴ Exhibit 3539-X0197, EDTI reply argument, paragraph 175.

⁷⁰⁵ Transcript, Volume 1, pages 153-154.

⁷⁰⁶ Exhibit 3539-X0197, EDTI reply argument, paragraph 178.

mid-year. The Commission agrees with EDTI that the mid-year convention does not mean that all capital additions in every year are exactly evenly spread. Therefore, the Commission does not find that directing EDTI to provide capital additions and expenditures by month is necessary to adequately test the impact of capital additions and expenditures related to working capital and included in the forecast revenue requirement in a given year.

775. With respect to debt issuances, the Commission acknowledges that EDTI, for years prior to 2015, issued its debt closer to the end of the year. The Commission notes, however, that for 2015, EDTI has taken a more proactive approach to issuing its debt on a basis more consistent with its forecasts, as evidenced by Mr. Chaudhary's testimony on behalf of EDTI:

What we've done last year is we applied to the Commission to have our approvals for debt issuances for 2014 and 2015 approved in advance, and what that has done is it's afforded us the opportunity to place our debt in 2015 in line with a date that's been included in our 2015 forecast in our application.⁷⁰⁷

776. In 2014, EDTI received approval to issue its debt in Decision 2014-308⁷⁰⁸ and issued its actual debt in June 2015.⁷⁰⁹ There is one more debt issue forecast for the test period in 2016.

777. The Commission agrees with the UCA that, from a conceptual perspective, working capital should reflect cash flows and short term monetary items. The Commission also accepts EDTI's statement that use of mid-year convention is the accepted norm that has been applied in recognizing rate base transactions. The Commission is not prepared to re-examine the mid-year convention related to working capital at this time.

778. The Commission notes that EDTI did not propose any changes to its methodology for calculating forecast working capital. The Commission has reviewed EDTI's forecast working capital requirements as set out in Table 38 above and approves EDTI's transmission working capital forecast for 2015 to 2017, subject to any adjustments that may be necessitated by other findings set out in this decision. EDTI is directed to make any necessary adjustments to its working capital calculations to give effect to Commission findings in this decision, in its compliance filing.

11 Return on rate base

779. EDTI provided its calculations of return on mid-year transmission rate base, including supporting details for both return on debt and return on equity (ROE) in Section 12 of the application. The applied-for revenue requirement calculations in EDTI's GTA assumed an ROE of 8.75 per cent and an equity ratio of 37 per cent on a placeholder basis pending the outcome of the Commission's 2013 Generic Cost of Capital decision.

780. On March 23, 2015, the AUC issued Decision 2191-D01-2015. 2013 Generic Cost of Capital (2013 GCOC decision).⁷¹⁰ In its decision, the Commission approved a generic rate of

⁷⁰⁷ Transcript, Volume 1, pages 153-154.

⁷⁰⁸ Decision 2014-308: EPCOR Distribution & Transmission Inc., Application for Approval of 2014 and 2015 Debt and Equity Issuance, Proceeding 3400, Application 1610831-1, November 7, 2014.

⁷⁰⁹ Exhibit 3539-X0197, EDTI reply argument, Table 12.1, page 67.

⁷¹⁰ Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.

return on common equity of 8.30 per cent for 2013, 2014 and 2015 for Alberta transmission and distribution utilities, including EDTI. The Commission also approved a capital structure of 64 per cent debt and 36 per cent equity for EDTI transmission for 2013, 2014 and 2015. The ROE and capital structure were approved on an interim basis for 2016 and each subsequent year thereafter unless otherwise directed by the Commission.

781. In the current proceeding and at the request of the Commission, EDTI revised its application on May 22, 2015, to reflect, among other things, the updated ROE and capital structure approved in the 2013 GCOC decision.⁷¹¹

782. In its update, EDTI stated that in addition to reflecting the change in ROE and capital structure approved by the Commission in its 2015 forecast revenue requirement, EDTI also revised its 2016 and 2017 forecast revenue requirements to reflect the 2013 GCOC decision ROE and capital structure on an interim basis. EDTI submitted that the impact of the 2013 GCOC decision resulted in a reduction to EDTI's forecast revenue requirement of \$1.55 million for 2015, \$1.57 million for 2016 and \$1.55 million for 2017.⁷¹²

783. EDTI's updated calculations of return on mid-year transmission rate base are set out in the table below:

⁷¹¹ Exhibit 3539-X0089, EDTI additional information – 2014 actuals.

⁷¹² Exhibit 3539-X0089, EDTI additional information – 2014 actuals, PDF page 29 of 35.

Table 39. Return on mid-year transmission rate base 2013-2017

Description	2013 Decision 2014-269	2013 actual*	2014 Decision 2014-269	2014 actual*	2015 forecast	2016 forecast	2017 forecast
	(\$ million)						
Mid-year rate base (net PP&E and working capital)	461.41	471.07	589.69	629.20	657.16	686.80	722.86
Capital structure - equity (%)	36.93%	35.62%	37.36%	37.19%	36.27%	35.80%	36.23%
Capital structure - debt (%)	63.07%	64.38%	62.64%	62.81%	63.73%	64.20%	63.77%
Mid-year rate base - equity	170.42	167.78	220.32	233.99	238.34	245.86	261.87
Mid-year rate base - debt	291.00	303.29	369.37	395.21	418.82	440.94	461.00
Cost of equity (%)	8.75%	6.67%	8.75%	10.81%	8.30%	8.30%	8.30%
Cost of debt (%)	5.11%	5.06%	5.10%	4.98%	4.98%	5.06%	5.08%
WACC (%)	6.45%	5.63%	6.46%	7.15%	6.18%	6.22%	6.25%
Return on mid-year rate base - equity	14.91	11.18	19.28	25.31	19.78	20.41	21.73
Return on mid-year rate base - debt	14.87	15.36	18.83	19.67	20.85	22.32	23.42
Total return on mid-year rate base	29.78	26.54	38.10	44.98	40.63	42.73	45.15
Over (under) 2013 and 2014 decision to actuals or forecast \$		(3.24)		6.88	2.53		
Over (under) 2013 and 2014 actuals and forecast \$				18.44	(4.35)	2.1	2.42

Source: Exhibit 3539-X0087, GTA schedules updated for 2014, schedule 28-1T. *Note: 2013 and 2014 actuals are restated per Decision 2010-505 and Decision 2014-269.

11.1 Return on equity

784. EDTI updated its 2015 forecast revenue requirement to reflect the change in ROE from 8.75 per cent to 8.30 per cent, as approved in the 2013 GCOC decision on a final basis. EDTI also updated its 2016 and 2017 forecast revenue requirements to reflect the ROE of 8.30 per cent, approved in the 2013 GCOC decision.⁷¹³

Commission findings

785. The Commission finds EDTI's use of the most recently approved ROE of 8.30 per cent for 2015 on a final basis, and for 2016 and 2017 on an interim basis, to be consistent with the Commission's findings in Decision 2191-D01-2015. The Commission directs EDTI to apply to true-up its ROE for 2016 and 2017 once a decision is issued in the next generic cost of capital proceeding.⁷¹⁴

⁷¹³ Exhibit 3539-X0089, EDTI additional information – 2014 actuals, PDF page 29 of 35 and Exhibit 3539-X0087, GTA schedules updated for 2014, Schedule 28-1T.

⁷¹⁴ Proceeding 20622, 2016 Generic Cost of Capital.

11.2 Capital structure

786. As discussed earlier in Section 3.4 of this decision, the applied-for revenue requirement calculations in EDTI's GTA schedules⁷¹⁵ used equity ratios of 37.46 per cent, 37.33 per cent and 37.23 per cent for the years 2015, 2016 and 2017 respectively, on a placeholder basis.

787. At the request of the Commission, EDTI revised its application on May 22, 2015, to reflect, among other things, the capital structure approved in the 2013 GCOC decision. EDTI stated that in addition to reflecting the change in ROE and capital structure approved by the Commission in its 2015 forecast revenue requirement, EDTI also updated its 2016 and 2017 forecast revenue requirements to reflect the 2013 GCOC ROE and capital structure on an interim basis.⁷¹⁶

788. The applied-for revenue requirement calculations in EDTI's GTA schedules (updated for 2014 actuals and the impact of the 2013 GCOC decision) used equity ratios of 36.27 per cent, 35.80 per cent and 36.23 per cent for the years 2015, 2016 and 2017 respectively.⁷¹⁷

Commission findings

789. As stated in Section 3.4 of this decision, the Commission directed EDTI to update certain schedules and to reflect the 2013 GCOC decision approved debt and equity ratios of 64.0 per cent and 36.0 per cent, respectively.

790. In its May 22, 2015 update, EDTI provided a schedule of transmission capital structure and average cost of capital for the year 2015. In lines 64 and 66 of the schedule, EDTI did not reflect the 2013 GCOC decision approved debt and equity ratios of 64.0 per cent and 36.0 per cent, respectively.⁷¹⁸ This also applied to the years 2016 and 2017.⁷¹⁹

791. The Commission is not satisfied that EDTI has complied with its direction to reflect the findings in the 2013 GCOC decision, as specified in the Commission's May 22, 2015 letter. EDTI is directed to make corrections to the schedules to reflect the approved debt and equity ratios for the year 2015 on a final basis and for the years 2016 and 2017, on an interim basis. The Commission directs EDTI in its compliance filing to this decision, to recalculate its forecast transmission capital structure and average cost of capital and transmission return on rate base for 2015, 2016 and 2017 using the Commission-approved debt and equity ratios of 64.0 per cent and 36.0 per cent, respectively.

11.3 Costs associated with long-term debt

792. EDTI forecast 2015 and 2016 long-term debt issues for its transmission operations of \$25 million and \$50 million, respectively. EDTI did not forecast any long-term debt issue for 2017.⁷²⁰

⁷¹⁵ Exhibit 0065.00.EDTI-3539, MFR Schedules, Schedule 28-1T.

⁷¹⁶ Exhibit 3539-X0089, EDTI additional information – 2014 actuals, PDF page 29 of 35.

⁷¹⁷ Exhibit 3539-X0089, EDTI additional information – 2014 actuals, PDF page 29 of 35 and Exhibit 3539-X0087, GTA schedules updated for 2014, Schedule 28-1T.

⁷¹⁸ Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 28-1T, lines 64 and 66.

⁷¹⁹ Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, Schedule 28-1T, lines 71, 73, 78 and 80.

⁷²⁰ Exhibit 0055.00.EDTI-3539, Appendix G-16, Dr. Evans evidence, page 13, PDF page 14 of 24.

793. In Direction 34 of Decision 2014-269, the Commission directed EDTI as follows:

The Commission directs EDTI, in its next TFO GTA, to provide two debt forecasts: one based on a forward curve and another based on the *Consensus Forecast*, and to support its choice of the method used in the application. Further, the Commission directs EDTI to provide a 30-year bond rate in order for the Commission to assess the reasonableness of EDTI's forecast cost of debt.⁷²¹

794. EDTI retained Dr. Robert Evans of Economic Research Associates Limited to provide estimates of the 2015, 2016 and 2017 costs of new debt (forecast debt costs) for its stand-alone transmission operations based on surveys of investor expectations reported in the *Consensus Forecasts*. EDTI also retained Dr. Evans to respond to Direction 34 of Decision 2014-269 by providing forward curve debt costs and to make recommendations in respect of which method should be used.⁷²² Over the course of the proceeding, Dr. Evans provided two updates to his report. The first update was provided in responses to IRs⁷²³ and the second update was provided on May 22, 2015.⁷²⁴

795. In his evidence, Dr. Evans discussed the difference between forecast debt costs and forward curve debt costs, and he stated the following:

A “forecast debt cost” is an estimate of what the cost of debt will be at some time in the future. This estimate is frequently developed using surveys of investor expectations (e.g., the *Consensus Forecasts* survey) and current estimates of maturity risk premiums and credit risk premiums as appropriate. The Commission and its predecessors have incorporated forecast debt costs for many years in utility revenue requirements.

In contrast, a “forward curve debt cost” is the cost today for locking in a debt cost rate at some future time for a specified term. The forward curve debt cost is frequently used in commercial lending, where a borrower has reasonably certain future requirements and wants to remove the risk of changes in financing costs between today and when the funds are required. The important distinction is that the “forward curve debt cost” is not a forecast of what the cost of debt will be at some future time. Instead, the “forward curve debt cost” is a current cost rate that reflects, in part, future expectations but also the value and risk of “locking in” a cost rate and quantum of financing today.⁷²⁵

796. To determine forecast debt costs, Dr. Evans used the same four-step process that had been applied in previous applications. First, Dr. Evans established the 2015, 2016 and 2017 forecast yields on 10-year government of Canada (GOC) bonds by referring to survey data, and the *Consensus Forecasts*. Second, he added a 60 basis points maturity premium in order to develop a forecast of the yields on long-term GOC bonds. Third, he added a credit risk premium of 160 basis points to reflect the A (Low) stand-alone credit rating of EDTI's transmission operations. Finally, he added an allowance of five basis points for financing costs to arrive at his estimates of the cost of new long-term debt of 3.85 per cent, 4.25 per cent and 4.95 per cent for

⁷²¹ Decision 2014-269, paragraph 466.

⁷²² Dr. Evans' report was provided as Appendix G-16 to the application, Exhibit 0055.00.EDTI-3539.

⁷²³ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-062.

⁷²⁴ Exhibit 3539-X0094, updating statement of Robert E. Evans.

⁷²⁵ Exhibit 0055.00.EDTI-3539, Dr. Evans evidence, pages 3-4, PDF pages 4-5 of 24.

2015, 2016 and 2017, respectively.⁷²⁶ These estimates were found at Table 12.3-2 of Dr. Evans' update.

797. To determine forward curve debt costs, Dr. Evans used a two-step process. First, Dr. Evans considered one-year, two-year and three-year forward curve yields on 30-year GOC bonds, for which the 30-year term matched the term of the debt that EDTI proposed to issue in 2015 and 2016. Second, the same credit risk premiums and financing costs used to establish forecast debt costs were added to the 30-year forward curve yields, to arrive at his estimates of the forward curve debt costs of 3.95 per cent, 4.05 per cent and 4.15 per cent for 2015, 2016 and 2017, respectively.⁷²⁷ These estimates were found at Table 12.3-4 of Dr. Evans' update.

798. Dr. Evans expressed a preference for continued use of the forecast debt cost method, but he was not averse to the use of forward curve debt costs, if there was no material change in the risks and return prospects of shareholders.⁷²⁸ Dr. Evans stated:

If EDTI, with the approval of the Commission, were to incorporate forward curve interest rates into its revenue requirement and if the utility were also permitted to actually "lock in" the costs of future debt financings at those cost rates using forward contracts, then there would be no material change in the risks incurred or benefits received by shareholders. EDTI assumes that the Commission would incorporate the actual forward curve contracted rate once that was known just as it does under the present regime when the actual cost of debt raised in the "spot" market becomes known at the time of issue.

Customers would benefit from the use of forward curve interest rates to the extent that the actual forward curve cost of utility debt is less than the "spot" cost at the time the financing would have otherwise taken place. Customers also face the risk that the reverse circumstance might apply.

Because interest costs are a deduction in arriving at a utility's common equity return, the opportunity to recover actual interest costs is an important ingredient in ensuring that a utility has the reasonable opportunity to earn its allowed rate of return on equity. The use of forward curve interest rates to establish debt costs for revenue requirement purposes is not unreasonable on its face as long as parties agree that the utility should be able to incorporate its actual forward curve cost of debt into revenue requirements, thus providing a reasonable opportunity to achieve the allowed rate of return on equity.⁷²⁹

799. Dr. Evans was questioned about the possibility of using forward curve cost rates as another form of forecast, for instance as an indicator of where the market thinks debt cost will actually be, for debt "of that quality at that point in time."⁷³⁰ The question posed to Dr. Evans was:

Q: So does it (the forward curve cost rate) not serve as an indicator of where the market or a market – where the derivative market thinks debt costs will be for that quality of debt two years out or three years out?

⁷²⁶ Exhibit 3539-X0094, updating statement of Robert E. Evans, pages 1-5, PDF pages 1-5 of 16.

⁷²⁷ Exhibit 3539-X0094, updating statement of Robert Evans, pages 6-7, PDF pages 6-7 of 16.

⁷²⁸ Exhibit 3539-X0193, EDTI argument, paragraph 647, PDF page 253 of 259.

⁷²⁹ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-63(b), (c) and (d).

⁷³⁰ Transcript, Volume 5, page 998.

And so can we not use that as an indicator of, you know, that's where we – there's where the market or a market thinks debt costs will be?

Now, that's different than, say, the conference board getting out its crystal ball and going "We think the interest rates will be at this point."

There is an actual market – there's people actual going, "I'm willing to lend you money two years hence at 2.49," or whatever the number is. And that is an indicator of what the company's actual debt costs might be were they to go to the market at that time. Because if somebody is willing to risk lending it to them at that time on the assumption that that will be a decent deal at that time.

So is there no way to sort of use that as an indicator for rate-setting purposes to say, "That's where we think debt costs will be one or two years out."⁷³¹

800. Dr. Evans responded:

A: No. The forward-curve cost is not a forecast. It is an actual cost today for delivery of funds at some point in the future.⁷³²

It is, of course, clear from the numbers that Ms. Sabo drew my attention to that there is at this time a not immaterial difference between the forecast cost of debt and the cost of locking in today of the forward curve. That may well exist solely because those in the market expect interest rates to spike over the next 18 months. That may well be the reason for that.

And so the important thing is that if you choose to go the forward-curve route, that you not, at the end of the day, if the company doesn't have the opportunity to actually lock in the forward-curve rate and if interest rates do spike, that you, at that point, approve whatever is the actual cost of debt as opposed to the forward-curve cost, or that you let the company actually lock in the forward-curve cost and have everyone agree that that's the cost that you're going to use.⁷³³

801. EDTI submitted that Dr. Evans' position is that forecast debt costs and forward curve debt costs are "apples and oranges" and the cost rates should not be averaged or combined because the essential characteristics of each are different. One is a forecast of a future cost rate while the other is a current cost rate for funds to be delivered in the future.⁷³⁴

802. EDTI noted that in information requests, the CCA had asked Dr. Evans to discuss the practicality of using a combination of the forecast debt cost approach for those issues that are uncertain in terms of timing or quantum and the forward curve approach for those issues that are more certain as to time and quantum of issue (a portfolio approach). EDTI submitted that it would not be opposed to this portfolio approach suggested by the CCA as long as the regulatory treatment of the forward curve portion would be that described by Dr. Evans where EDTI actually locks in the cost rate of the future financing today; and that cost rate, including all costs

⁷³¹ Transcript, Volume 5, pages 998-999.

⁷³² Transcript, Volume 5, page 998.

⁷³³ Transcript, Volume 5, page 1000.

⁷³⁴ Exhibit 3539-X0193, EDTI argument, paragraph 650, PDF page 255 of 259.

required to actually execute the forecast curve transaction and lock in the cost rate, is flowed through in rates irrespective of the actual spot rate when the financing is obtained.⁷³⁵

803. EDTI submitted the following conclusions with respect to the cost of new long-term debt:⁷³⁶

- The Commission should continue using the forecast method to develop the cost of new long-term debt. The updated cost rates provided by Dr. Evans are 3.85 per cent, 4.25 per cent and 4.95 per cent for 2015, 2016 and 2017 respectively.
- Because the 2015 actual cost rate will likely be known before a decision is made in this matter, EDTI proposed that the actual 2015 cost rate be made part of its compliance filing in place of the 3.85 per cent current forecast rate.⁷³⁷
- If the Commission considers that it would be appropriate to rely on forward curve cost rates for 2016, then EDTI should be permitted the opportunity to lock in the actual cost of some or all of its \$50 million debt issue as soon as practicable with the locked-in cost rate used as the actual cost of debt. Customers, the Commission and EDTI should be advised of the ground rules in advance, because there is little regulatory precedent regarding use of the forward curve financings.
- The possibility of a portfolio approach such as that described by CCA is acceptable to EDTI as long as the regulatory treatment of each part of the total portfolio is reasonable in light of the risk and timing differences between the forecast method and the forward curve method.
- If the Commission wishes to consider using forward curve debt costs as “another forecast” rather than as actual debt costs, then a study should be prepared to determine the relative long-term historical forecast accuracies of: (i) forecast cost rates using Consensus Forecast and other data; (ii) forward curve cost rates; and (iii) various combinations giving alternative weighting to (i) and (ii).

804. In argument, the CCA submitted that there is merit in using the forward curve to establish the underlying long Canada bond rates to determine the cost of debt for EDTI because the forward curve approach appears to produce more stable and accurate forecasts over time than the forecast debt cost method.⁷³⁸ The CCA included the following table to support its view:

⁷³⁵ Exhibit 3539-X0193, EDTI argument, paragraphs 651-653, PDF pages 255-257 of 259.

⁷³⁶ Exhibit 3539-X0193, EDTI argument, paragraphs 659-663, PDF page 258 of 259.

⁷³⁷ EDTI noted in its argument that the actual cost rate for EDTI’s June 2015 issue is 4.17 per cent. Noted at Exhibit 3539-X0193, footnote 542.

⁷³⁸ Exhibit 3539-X0194, CCA argument, paragraph 91, PDF page 29 of 42.

Table 40. Comparison of forecast debt costs versus forward curve debt costs⁷³⁹

			2015	2016	2017
	Forecast costs of new long-term debt		(%)		
1	November 25, 2014	Ex 55 Appendix G-16	4.85	5.45	6.00
2	February 6, 2015	Ex X005 EDTI-AUC-2015FEB06-062	4.65	5.25	5.80
3	May 2015	Ex X0094	3.85	4.25	4.95
4		Range of forecasts	1.00	1.20	1.05
	Forward curve costs of new long-term debt				
5	November 25, 2014	Ex 55 Appendix G-16	4.20	4.25	4.3
6	February 6, 2015	Ex X005 EDTI-AUC-2015FEB06-062	3.75	3.85	3.90
7	May 2015	Ex X0094	3.95	4.05	4.15
8		Range of forward curve	0.45	0.40	0.40
	Average of two methods				
9	November 25, 2014	CCA calculation	4.53	4.85	5.15
10	February 6, 2015	CCA calculation	4.20	4.55	4.85
11	May 2015	CCA calculation	3.90	4.15	4.55
	Differences between two methods				
12	November 25, 2014	CCA calculation	0.65	1.20	1.70
13	February 6, 2015	CCA calculation	0.90	1.40	1.90
14	May 2015	CCA calculation	-0.10	0.20	0.80

805. The CCA argued that when comparing the two methods in Table 40 above, the range of volatility using the forecast debt costs approach is more than double that of the forward curve debt costs approach.⁷⁴⁰

806. The CCA also argued that the long Canada bond rates based on the forward curve approach reflects market based rates.⁷⁴¹ The CCA included the following table to support this view:

⁷³⁹ Exhibit 3539-X0194, CCA argument, paragraph 92, PDF page 30 of 42.

⁷⁴⁰ Exhibit 3539-X0194, CCA argument, paragraph 93, PDF page 31 of 42.

⁷⁴¹ Exhibit 3539-X0194, CCA argument, paragraph 91, PDF page 29 of 42.

Table 41. Comparison of 10-year bond and 30-year bond costs⁷⁴²

			2015	2016	2017
	Forecast costs of 10-year bond				
1	November 25, 2014	Ex 55 Appendix G-16	2.70	3.30	3.85
2	February 6, 2015	Ex X005 EDTI-AUC-2015FEB06-062	2.40	3.00	3.55
3	May 2015	Ex X0094	1.60	2.0	2.7
4		Range of forecasts*			
	Forward curve costs of 30-year bond				
5	November 25, 2014	Ex 55 Appendix G-16	2.57	2.65	2.71
6	February 6, 2015	Ex X005 EDTI-AUC-2015FEB06-062	2.07	2.14	2.19
7	May 2015	Ex X0094	2.32	2.41	2.49
8		Range of forward curve**	0.45%	0.40%	0.40%

807. The CCA argued that in Table 41 above, there is much less volatility in the forward curve rate and that “it is important to note that the forward curve is the actual market rate which those parties who are actually prepared to lend money base their debt rates on.”⁷⁴³

808. The CCA submitted that it is not clear what EDTI is requesting when stating that “the utility should be able to incorporate its actual forward curve cost of debt into revenue requirements.” The CCA submitted that actual debt costs, whether incurred by a debt issue or by a forward curve only become incorporated into rates after the test period. In the proceeding following the current test period, the actual debt and associated costs will be tested and the Commission will determine whether those costs should be embedded in rates.⁷⁴⁴

809. The CCA stated that the Commission will test the prudence of the actual debt rate incurred, whether it was incurred through a forward curve or through a spot rate, at the time of issuance. EDTI must demonstrate that the benefits of the timing of such issues outweigh the risks and costs arising therefrom and the process of testing actual rates will occur regardless of whether the debt forecast or the forward curve method of debt issuance was used.⁷⁴⁵

810. The CCA submitted that in Alberta the establishment of debt rates in the decision, however they are derived, is included in the rates that the utility receives during the test period. The actual costs, regardless of how the debt is issued, are paid by the utility and have no impact on rates during the test period. It is only in the case where there is a debt deferral account that the actual costs are trued up to the forecast costs; and that is only done in the subsequent proceeding. Outside of the test period, the embedded cost of debt is included in rates on a go-forward basis after prudence testing.⁷⁴⁶

811. In the CCA’s view, the issue of reimbursing EDTI for actual costs should a forward contract be used is a “red herring.” The CCA stated that, “while it may be that the mechanical

⁷⁴² Exhibit 3539-X0194, CCA argument, paragraph 95, PDF page 31 of 42. *The Commission observes on line 4 of the CCA’s table, there was no range of forecast provided. The Commission calculates the range to be 1.1 per cent, 1.3 per cent and 1.15 per cent for the years 2015, 2016 and 2017, respectively. **The Commission also observes on line 8 of the CCA’s table, the range of forward curve per cents appear to be incorrect. The Commission calculates the range to be 0.50 per cent, 0.51 per cent and 0.52 per cent for the years 2015, 2016 and 2017, respectively.

⁷⁴³ Exhibit 3539-X0194, CCA argument, paragraph 96, PDF page 31 of 42.

⁷⁴⁴ Exhibit 3539-X0198, CCA reply argument, paragraph 73, PDF page 24 of 28.

⁷⁴⁵ Exhibit 3539-X0194, CCA argument, paragraph 124, PDF page 40 of 42.

⁷⁴⁶ Exhibit 3539-X0198, CCA reply argument, paragraph 74, PDF pages 24-25 of 28.

process of incurring the debt is different under a forward cost curve contract, generally that is hardly an issue as parties historically have not gotten into the details and mechanics of how utilities acquire the debt and the particular instrument they use.⁷⁴⁷

812. The CCA submitted that EDTI had confused the issue of forecasts and the rate at which debt can be issued. EDTI pays actual debt costs throughout the term of the debt issue, whereas customers pay the rate determined in the decision, regardless of how determined, during the test period and thereafter pay the embedded rate. Therefore, apart from the two out of thirty or so years of the life of the debt, the actual costs are paid for by customers.⁷⁴⁸

813. The CCA submitted that if the Commission accepts Dr. Evans' forecast debt costs, the debt rates included in the decision will be 3.85 per cent, and 4.25 per cent for 2015 and 2016. If the Commission accepts that EDTI can lock in rates today for 3.95 per cent and 4.05 per cent, the 20 basis points difference amounts to \$100,000 per year on the \$50 million that EDTI proposes to finance in 2016 or \$3 million over the life of a 30-year debt issue.⁷⁴⁹

814. The CCA stated that there is no need to conduct a study about the accuracy of one method relative to another and that the question is not which method is more accurate. The CCA submitted that parties' and the Commission's role is to provide a reasonable debt rate to be included in rates, after which EDTI can proceed to issue debt in the best manner it sees fit. Therefore, the CCA submitted that the only decision the Commission need make is what debt rate to use in the decision for each of 2015 and 2016.⁷⁵⁰

815. The CCA submitted that it supported Dr. Evans' forecast debt cost for 2015 and Dr. Evans' forward curve debt cost for 2016, therefore the rates to be included in the decision would be 3.85 per cent and 4.05 per cent, respectively.⁷⁵¹

816. EDTI replied that the CCA's recommendation in argument uses different methods in different years and that the only discernable relationship between the CCA's 2015 and 2016 recommendation is that the lowest cost rate in each year has been chosen, irrespective of which method produces the lowest cost rate.⁷⁵² EDTI noted that its actual June 2015 debt issue came in at 4.17 per cent.⁷⁵³

817. EDTI submitted that the CCA's argument went beyond the evidence on the record. EDTI submitted that there is no expert evidence to support the CCA's argument that "the forward curve approach may also be used to forecast the market expectations for long term borrowing," and that Dr. Evans' evidence is to the contrary. EDTI submitted that the CCA used inferences on the record, but that the resulting construction was the CCA's opinion not evidence.⁷⁵⁴

818. EDTI submitted that the CCA's argument that "long Canada bond rates based on the forward curve approach reflect market based rates"⁷⁵⁵ was once again new evidence and that

⁷⁴⁷ Exhibit 3539-X0194, CCA argument, paragraph 123, PDF page 40 of 42.

⁷⁴⁸ Exhibit 3539-X0198, CCA reply argument, paragraph 80, PDF page 26 of 28.

⁷⁴⁹ Exhibit 3539-X0198, CCA reply argument, paragraph 78, PDF page 26 of 28.

⁷⁵⁰ Exhibit 3539-X0198, CCA reply argument, paragraphs 81-86, PDF pages 26-28 of 28.

⁷⁵¹ Exhibit 3539-X0198, CCA reply argument, paragraph 88, PDF page 28 of 28.

⁷⁵² Exhibit 3539-X0197, EDTI reply argument, paragraph 190, PDF page 70 of 80.

⁷⁵³ Exhibit 3539-X0197, EDTI reply argument, page 67, Table 12.1, PDF page 70 of 80.

⁷⁵⁴ Exhibit 3539-X0197, EDTI reply argument, paragraphs 192 and 193, PDF pages 72-73 of 80.

⁷⁵⁵ Exhibit 3539-X0197, EDTI reply argument, paragraphs 193 and 196, PDF pages 72-73 of 80.

there was no expert evidence to support this conclusion. EDTI submitted that, as indicated by Dr. Evans, forward curve rates are negotiated rates with large banks and financial institutions and that these are distinct from debt costs that are observable in public markets where securities are traded.⁷⁵⁶

819. EDTI replied that the CCA's volatility analysis set out in its argument is misleading. The forecast method is applied using yields on 10-year Government of Canada bonds. But the forward curve yields in this analysis are 30-year obligations. Given the tendency for the yields of longer-term bonds to be more stable and less subject to movements in shorter-term administrative interest rates, the analysis is biased in favour of greater volatility associated with the forecast method.⁷⁵⁷

820. EDTI submitted that the CCA has not understood the concept of market rates. EDTI stated that Dr. Evans' evidence is that conventional bond issues such as those made in the past by most utilities and pipelines are done through investment dealers, and the cost rates at which those financings take place are subject to competitive conditions in markets for tradeable securities at the time of the issue. Therefore, it is possible to compare issue costs to costs incurred by other public issuers of securities. In contrast, there is no "tradeable market" of forward-curve financings because they are typically undertaken with a firm's commercial bank on a negotiated basis. The negotiated terms will reflect overall market conditions at the time the arrangements are made, but there is no public market in which forward curve arrangements or obligations trade and which can be readily used as a benchmark for determining the reasonableness of a negotiated forward-curve financing for a specific utility.⁷⁵⁸

821. EDTI submitted that Dr. Evans explained why it would be unfair to use the forward curve debt rate as a forecast and not permit EDTI to actually lock-in forward curve financing because:

... is not reasonable and would be contrary to the public interest inasmuch as it would needlessly increase risks to utility shareholders and potentially deny to customers the very benefits from forward curve financing that are the purpose of the exercise in the first instance. (Footnote: If interest rates declined further from current levels, then the positions of shareholders and customers would reverse. However, since the prospect of rising interest rates is a significant impetus for considering forward curve financing, the possibility that future "spot" interest rates could decline below current forward curve rates is not assigned a high probability. If parties do assign a high probability to such an event, then customers would be clearly "better off" under the current regulatory regime, obviating the need for consideration of forward curve financing.⁷⁵⁹

Commission findings

822. EDTI submitted that the actual cost of its bond issue in June 2015 was 4.17 per cent and that both the 2015 forecast debt cost of 3.85 per cent and forward curve debt cost of 3.95 per cent understated this actual cost.⁷⁶⁰

⁷⁵⁶ Transcript, Volume 5, pages 966-967 and 977.

⁷⁵⁷ Exhibit 3539-X0197, EDTI reply argument, paragraph 197, PDF page 72 of 80.

⁷⁵⁸ Exhibit 3539-X0197, EDTI reply argument, paragraph 202-203, PDF page 74 of 80.

⁷⁵⁹ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-63(e), (f) and (g).

⁷⁶⁰ Exhibit 3539-X0197, EDTI reply argument, paragraph 188 and Table 12.1, PDF pages 69-70 of 80.

823. As the actual cost of debt for 2015 is known, the Commission approves EDTI's request to reflect its actual cost of debt issued for 2015 of 4.17 per cent in its forecast revenue requirement for 2015, rather than the forecast debt cost of 3.85 per cent or the forward curve debt cost of 3.95 per cent. EDTI is directed to reflect the 4.17 per cent for its 2015 cost of debt in its compliance filing to this decision.

824. In Decision 2014-269, the Commission provided the following direction:

466. The Commission directs EDTI, in its next TFO GTA, to provide two debt forecasts: one based on a forward curve and another based on the *Consensus Forecast*, and to support its choice of the method used in the application. Further, the Commission directs EDTI to provide a 30-year bond rate in order for the Commission to assess the reasonableness of EDTI's forecast cost of debt.⁷⁶¹

825. In response to the Commission's direction, EDTI provided the *Consensus Forecast* and Dr. Evans provided evidence with respect to EDTI's cost of debt were it to raise debt in the forward curve debt market, if the Commission were to direct EDTI to do so.

826. The Commission's purpose for its direction was to evaluate different methods to determine EDTI's forecast debt for rate setting purposes. The Commission wanted to explore alternatives to the *Consensus Forecast* for forecasting debt costs in order to better understand what may be a reasonable forecast of interest rates during the test period.

827. The Commission agrees with the CCA that the issue before the Commission is what debt cost rate should be used for the forecast of debt costs over the test period and that this forecast should include the best information available. There has been evidence, argument and reply argument on the record of this proceeding with respect to how EDTI may raise debt in the forward curve market, if the Commission directed EDTI to do so. The Commission has weighed the evidence with respect to setting forecast debt costs, and whether the forward curve debt costs can be used in determining forecasts, consistent with the Commission's statutory mandate to set just and reasonable rates. In doing so, the Commission has explored what is the best debt rate forecast available to the Commission for the purpose of setting rates during the test period.

828. During the oral hearing, the panel canvassed this issue, as follows:

Q. Okay. So in some of the discussion that you were having with Ms. Sabo, it sounded as if the discussion was around having the company actually raise debt in the forward market or in the derivative market.

And my understanding was that what we were talking about or what we were seeing in the application was an alternative approach to, say, going to the Conference Board of Canada forecast to try and get a bead on what do we think interest rates will be two years out, three years out for the purpose of trying to establish what that forecast cost of debt for the company would be in order to set rates.

Are we clear that that's what we're doing?

A. The forward-curve cost is different from the forecast cost. And -- so the purpose is actually slightly different. If you wanted to use forward-curve financing, then you would

⁷⁶¹ Decision 2014-269, paragraph 466.

be seeking to have the company lock in a cost rate today that would become known, perhaps even before the beginning of the test year in question, let's say, 2016, and you would then adopt that as the regulatory cost of debt irrespective of what after the fact the spot cost rate would be in mid-2016 and irrespective of whether or not that turned out to be, in hindsight, a good decision or a poor decision.

So that is one way of dealing with the cost of debt from a regulatory perspective. And if you believe that interest rates are poised to spike or if you believe that investor expectations are unlikely to decline from current levels, then you might well want to see that kind of an option exercised.

The other option is to forecast the cost of debt for 2016, build the forecast into the rates, and then afterwards adjust to what the actual is as at the time the financing takes place.

So those are two different options. Under the forward-curve option, I think you -- my advice to you is that you and your fellow commissioners in some sense protect yourselves against shameless Monday morning quarterbacking by any of the parties before you by making sure everyone's onboard with that forward-curve financing before you authorize it and before the company locks it in.

Q. And, see, that's where I think we might be missing each other completely, because could we not use the forward-curve data as another form of forecast, which we could arguably adjust to take out any derivative costs or returns that had been built into it for the individuals who are going to take the risk on the option, and simply look at it as an indicator of where the market thinks debt cost will actually be for debt of that quality at that point in time?⁷⁶²

829. With respect to using forward curve debt costs as a forecast, Dr. Evans responded to Commission panel questions:

Q. What if it's just a forecast cost for the purposes of rates being set, which will ultimately be adjusted at the time of the next GTA for the actual cost of debt incurred by the company? It's just a different forecast.

And, granted, if the actual debt history of the company three years hence is different than what the forecast that was used to set rates was and you make an adjustment at that time, is that workable? Is that reasonable? Because one way or the other, the Commission has to come up with a forecast of what those future debt instruments will actually cost. And if you use the forward curve as a way of saying for forecast purposes that's the number -- we can talk about whether you need any adjustments to it -- recognizing that it's a forecast, and the actual performance of the debt instruments may be different, but that's going to be adjusted for when you reset the rates at the time of the next GTA, is there anything wrong with that in your view, sir?

A. That would be workable, subject to two caveats. That at the time of the issue, the actual issue, that you do not judge the reasonableness of that cost by reference to the previously available forward-curve cost. In other words, if the actual cost ends up being, just to use a number, 4 percent, and the forward-curve cost would have been six months before or nine months before, say, 3 percent, that you do not say, well, you should have done this, so now we're only going to flow through 3 percent.

⁷⁶² Transcript, Volume 5, pages 996-998.

Q. That's not -- that's not what I'm suggesting. I'm suggesting you would use 4 percent in that case.

A. That's Monday morning quarterbacking.

Q. Right.

A. And in the case of transmission, where there's basically one customer, I think it becomes easier to do what you're suggesting, which is if there's a difference then between the forecast and the actual -- and there will be some difference, long or short -- but as long as you're permitted to flow that through, then we're back to the actual cost. And I think that would be fine.

Q. Right. But let's be clear, that you would only be able to flow it through on a go-forward basis from the time of the commencement of the next general tariff application. But, in effect, the company would bear the risk of it being either greater or lower than the forecast during the three years of the test period, and then you would true it up on a go-forward basis at the time of the next GTA. I want to be clear that's what we're talking about.

A. I guess, I would be a little bit troubled by that because now we're using something that isn't really a forecast rate. And we're saying, well, in the past Consensus Forecast has tended to overestimate. Maybe this will in some way help to reduce that. Because it happens to be a lower rate.

But I -- and then I know that that's -- that's not quite what you're saying, but I think you have to use the right concept for the right purpose.

Q. Just to be clear, I'm not saying take the forward curve because it happens to be lower. I mean, if it happened to be higher, I would still take the forward curve if we understood that that was a better indicator of what those future interest rates would actually be.

I mean, it needs to cut both ways; right? It's just looking for a measure of what that forecast debt cost will be and looking at whether or not the forward curve gives the Commission a decent indication of what those interest costs will be. Purely for the purposes of you've got to have a forecast so you can set rates.

A. Yeah. I would urge you to consider that and to, I guess, move along the lines which I have suggested here. And if you feel that forward-curve financing is something that is appropriate, that you undertake in your decision to make it plain where you come out so that parties know what to expect in terms of the future.⁷⁶³

830. The Commission has reviewed the evidence of Dr. Evans and the submissions by parties on this issue. Dr. Evans submitted that if EDTI were to incorporate forward curve interest rates into its revenue requirement and if the utility were also permitted to actually “lock in” the costs of future debt financings at those rates using forward contracts, then there would be no material change in the risks incurred or benefits received by shareholders.⁷⁶⁴ Dr. Evans also submitted that to direct EDTI to use the forward curve cost rate and not allow EDTI to lock-in rates would be

⁷⁶³ Transcript, Volume 5, pages 1005-1008.

⁷⁶⁴ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-63(b), (c) and (d).

unfair, un-reasonable and contrary to the public interest inasmuch as it would needlessly increase risks to utility shareholders.⁷⁶⁵

831. EDTI asserted that to use the forward curve cost rate as the forecast to be included in its revenue requirement, and not allow EDTI to lock-in those rates would be un-reasonable. The Commission disagrees. This is because the use of the forward curve cost rate as a forecast would not unreasonably increase risks to utility shareholders.

832. There is no evidence on the record of this proceeding that a forecast based on the forward curve introduces any more risk than a forecast based on the *Consensus Forecast*. In any event, forecast debt cost rates are included in forecast revenue requirement, based on the best information available at the time the forecast is approved. The risk that the actual debt costs incurred during the forecast period differ from the forecast amount, is part of the inherent forecast risk faced by utilities when setting forecast revenue requirement. The forecast risk associated with debt rates is not substantively different than the risk associated with any other forecast cost to be included in a utility's forecast revenue requirement. In keeping with the risks of providing utility service, the Commission finds that EDTI bears the inherent risk that forecast debt cost rates, as approved in the GTA proceeding on which its tariff is based, may not materialize in practice. In any event, EDTI is compensated for this forecast risk as part of the return on equity that it receives.

833. Although the consideration of the two methodologies examined by Dr. Evans in his evidence was based on the assumption that the Commission would direct EDTI to implement the approved forecast debt costs or, in the alternative, direct EDTI to adopt forward curve debt costs for securing debt, the Commission considers that Dr. Evans' estimated forecast costs of new long-term debt and estimated forward curve costs of new long-term debt provided in Tables 12.3-2 and 12.3-4 of his updated evidence provide a sufficient basis to assess debt cost forecasts for 2016.

834. The CCA stated that the forward curve is the forecast market rate at which parties are actually prepared to contract to lend money. In response to the CCA, EDTI indicated that there is no public market in which forward curve arrangements or obligations trade that can be readily used as a benchmark for determining the reasonableness of a negotiated forward curve financing. Although, there is no public market for forward curve arrangements, there is a market, and the Commission considers that the forward curve acts as an indication of what future interest rates are currently expected to be and can be considered for forecasting purposes.

835. EDTI proposed that, if the Commission were to adopt forward curve debt cost rates, for the purposes of establishing the debt costs in EDTI's revenue requirement, then EDTI is prepared to lock-in the actual cost rate using forward curve agreements, assuming no material change in the market in the interim.⁷⁶⁶ However, the Commission's consideration of the use of the forward curve as a forecast, does not mean that the Commission is required to make a determination on whether EDTI would be required to lock-in its actual cost of debt using the forward curve for the test years. To be clear, in this decision, the Commission is setting a reasonable forecast debt cost for the purposes of establishing EDTI's forecast revenue requirement for the test period. The Commission is not establishing an actual cost of debt.

⁷⁶⁵ Exhibit 3539-X0005, EDTI-AUC-2015FEB06-63(e), (f) and (g).

⁷⁶⁶ Exhibit 3539-X0197, EDTI reply argument, paragraph 212, PDF page 78 of 80.

836. The Commission is of the view that the *Consensus Forecast* is unrelated to market transactions, while forward curves reflect actual market transactions. Accordingly, the Commission accepts the forward curve as a reasonable indicator of interest rates during the test period.

837. The Commission is mindful of EDTI's submissions that new evidence was presented by the CCA in argument on a number of cost of debt matters. However, the information and calculations in tables 40 and 41 were prepared from evidence on the record other than provided in the CCA argument. EDTI was able to comment on the reformulated information and in fact, EDTI provided its responses to this information in reply argument.

838. Accordingly, the Commission finds that the 2016 forward curve cost of debt of 4.05 per cent is a reasonable forecast of the cost of debt in 2016. EDTI is directed to reflect the 4.05 per cent cost of debt for 2016 in its compliance filing to this decision.

839. The Commission approves the forecast cost of debt at the actual cost of 4.17 per cent for 2015 and 4.05 per cent for 2016, for new long-term debt issues, as set out above. EDTI has not forecast a debt issue for 2017, and therefore the Commission does not need to make a determination on the forecast cost of new debt for 2017. For revenue requirement purposes, the Commission directs EDTI to set its embedded cost of debt for 2017 equivalent to its embedded cost of debt including EDTI's approved 2015 and 2016 debt issue costs, as shown in EDTI's schedule of debt capital employed and embedded cost, Schedule 28-2T,⁷⁶⁷ and adjusted for the Commission's findings with respect to the 2016 forecast cost of new debt.

12 Depreciation

840. In its application, EDTI continued to use the direct life method (DLM) of depreciation. This method was first approved for use by EDTI in determining its depreciation expense in Decision 2006-054,⁷⁶⁸ respecting assets other than vehicles, and Decision 2008-125,⁷⁶⁹ respecting vehicles.

841. EDTI did not provide a depreciation study in its application, nor did EDTI propose changes to its depreciation methodology or depreciation parameters related to average service life, curve or net salvage.

842. EDTI applied the previously approved depreciation rates to its forecast mid-year property, plant and equipment balances for the three test years. Historical and forecast information is provided in the following table:

⁷⁶⁷ Exhibit 3539-X0087, GRA schedules updated for 214 actuals, Schedule 28-2T, years 2016 and 2017.

⁷⁶⁸ Decision 2006-054: EPCOR Transmission Inc., 2005/2006 Transmission Facility Owner Tariff, Application 1389884, EPCOR Distribution Inc., 2005/2006 Distribution Tariff – Phase I, Application 1389885, June 15, 2006.

⁷⁶⁹ Decision 2008-125: EPCOR Distribution & Transmission Inc., 2007-2009 Distribution Tariff, 2007-2009 Transmission Facility Owners Tariff, Code of Conduct Exemption, Proceeding 14, Application 1558686-1, December 3, 2008.

Table 42. Summary of depreciation expense 2013-2017

Description	2013 Decision 2014-269	2013 actual	2014 Decision 2014-269	2014 actual	2015 impacted forecast	2016 Impacted forecast	2017 impacted forecast
	(\$ million)						
Gross provision for depreciation							
Transmission	18.08	18.18	21.47	21.89	23.42	24.95	26.53
Direct general PP&E	.85	.86	1.07	.97	1.04	1.09	1.15
Subtotal gross provision	18.93	19.05	22.54	22.86	24.45	26.04	27.67
Amortization of reserve difference	(0.35)	(0.35)	(0.35)	(0.35)	(0.34)	(0.34)	(0.34)
Amortization of contributions	(1.77)	(1.80)	(1.79)	(1.81)	(1.84)	(1.85)	(2.14)
Total depreciation expense	16.81	16.89	20.40	20.70	22.27	23.84	25.19
Over (under) 2013 and 2014 decision to actuals or forecast \$		0.09		0.30	1.87		
Over (under) 2013 and 2014 decision to actuals or forecast %		0.5%		1.5%	9.2%		

Source: Exhibit 3539-X0087, GTA schedules updated for 2014 actuals, schedules 6-1 and 6-2.

843. In Decision 2014-269, the Commission directed as follows:

488. The Commission directs EDTI to maintain its current depreciation practices for the Heartland assets at this time. However, the Commission directs EDTI to maintain the accounting and depreciation records for its Heartland assets, and assets of a similar nature, in a manner that would allow EDTI at some future point to isolate the depreciation and net book value for those specific assets. The Commission also directs EDTI to explore the effects of ISO Rule 502.2 as it relates to EDTI's transmission lines and towers. Specifically, EDTI should consider the requirements of enhanced functional specifications, and the impact that any new design and selection requirements may have on the expected service lives of newly constructed assets falling under this rule.

489. The Commission further directs EDTI to maintain the 2013 and 2014 forecast depreciation expense respecting the Heartland transmission line assets on a placeholder basis until such time that an AESO directed projects review process for EDTI is undertaken to determine the prudence of the final capital additions and the related calculations of return and depreciation related to the Heartland transmission line assets.

844. In both its compliance filing to Decision 2014-269 and its 2015-2017 GTA, EDTI confirmed it had maintained its current depreciation practices for the Heartland project assets, and identified the Heartland project assets in its accounting and depreciation records in a manner that would allow for separate identification of the depreciation and net book value of the assets at a future point in time. EDTI explained in its compliance filing, that it would explore the effects of ISO Rule 502.2 and include applicable findings in its next tariff application, as ISO Rule 502.2 was in the process of being reviewed and potentially updated by the Transmission Rules/Towers Review Working group. EDTI also confirmed that its 2013 and 2014 forecast

depreciation expense for the Heartland project assets remained on a placeholder basis until such time as the AltaLink 2013-2014 DACDA application is finalized.^{770 771}

12.1 Need for a review of depreciation parameters and depreciation methodology

845. During the oral hearing, the Commission explored in further detail the timing of, and the expectation for, any update to EDTI's depreciation parameters or a methodology review by EDTI. The Commission also questioned EDTI's understanding of the current status of the ISO Rule 502.2 working group assessment as it relates to newly constructed assets falling under this rule. EDTI responded to questions by Commission counsel regarding the underlying principles of its simplified (direct life) method of depreciation. EDTI stated that the DLM does not require an annual review of average service lives and that EDTI adopted this method in response to a Commission direction to implement a simple method of depreciation which is easy to maintain, would not require a significant amount of recordkeeping and would be fairly easy to understand.⁷⁷²

846. EDTI stated that it was unaware of any other way of dealing with the costs of removing an existing asset from service, under the DLM of depreciation, other than to capitalize those costs into the new asset. In the case of costs associated with removing an asset where the asset was not being replaced, the costs would be treated as decommissioning costs and would be expensed.⁷⁷³

847. EDTI indicated that it was planning to undertake a depreciation study for both EDTI distribution and transmission for its 2018 forecast, but was not aware if alternatives to DLM would be examined. EDTI considered that moving away from DLM would result in a significant change to its business that could not be justified by any benefits associated with such a move.

848. EDTI described several factors taken into consideration when a depreciation study is completed such as infant mortality of assets, service lives used by comparable utilities, recommendations from manufacturers and any historical reasons for impacts on an asset's life such as weather, fires or storms. EDTI stated that at the time of its last technical update to review asset service lives in 2012, some categories of lives were adjusted to reflect the impact of recent technological changes.

849. EDTI confirmed that it had not explored the effects of ISO Rule 502.2 on its transmission lines and towers, but subject to the availability of the revised version of ISO Rule 502.2, it intended doing so for the purpose of its next depreciation study.⁷⁷⁴

850. EDTI stated in its argument, that the record demonstrated that the applied-for depreciation expense and method used to determine its depreciation expense are reasonable and prudent and should be approved by the Commission.⁷⁷⁵

⁷⁷⁰ Proceeding 3474, Exhibit 0001.00.EDTI-3474, 2013-2014 TFO Tariff Application, paragraphs 52-54, PDF page 25 of 175.

⁷⁷¹ Exhibit 0004.00.EDTI-3539, Appendix A, paragraphs 58-59, PDF pages 20-21 of 21.

⁷⁷² Transcript, Volume 2, page 360.

⁷⁷³ Transcript, Volume 2, page 375.

⁷⁷⁴ Transcript, Volume 2, pages 370-371.

⁷⁷⁵ Exhibit 3539-X0193, EDTI argument, paragraph 616, PDF page 246 of 259.

Commission findings

851. The Commission has reviewed the calculation of EDTI's depreciation expense for the test years and is satisfied with the calculations. On that basis, subject to true-up, or adjustments arising from directions elsewhere in this decision, the Commission approves EDTI's depreciation expense, as filed.

852. The Commission is also satisfied with EDTI's plans to undertake a depreciation study for the purposes of its next tariff application and directs EDTI to conduct and file a depreciation study in its next GTA. The Commission also directs EDTI to conduct and file, as a component of the depreciation study, explicit research and conclusions respecting alternative methods of accounting for the cost of removal of (old) retired assets under the DLM of depreciation beyond EDTI's current practice of capitalizing the cost of removal at the time a (new) replacement asset is installed and placed into service.

853. Further, the Commission considers it necessary for EDTI to explore the effects of the ISO Rule 502.2 functional specifications on the estimated useful service lives of EDTI's transmission lines and towers, and to file its findings in EDTI's next GTA. The Commission directs that EDTI include consideration of the estimated useful service lives of EDTI's transmission lines and towers as a component of the aforementioned depreciation study, irrespective of the availability of the revised version of ISO Rule 502.2. EDTI shall refer to the version of ISO Rule 502.2 that was in place at the time the Heartland project was constructed and, should the functional specifications change, file the same information under the new version of ISO Rule 502.2. EDTI is further directed in its consideration of service lives to consider other sources of information respecting estimated useful service lives, such as manufacturer's information, engineering studies or economic studies⁷⁷⁶ for the Heartland project lines and towers.

12.2 Heartland project – depreciation parameters

854. In argument, the CCA recommended EDTI adopt the average service life and net salvage parameters that will be determined by the Commission for AltaLink in Proceeding 3524 for EDTI's portion of the Heartland project assets. The CCA submitted that the updated parameters ultimately approved in Proceeding 3524 should be approved on a placeholder basis and used to calculate depreciation expense on EDTI's portion of the Heartland project in EDTI's 2015-2017 AESO directed projects deferral account reconciliation.⁷⁷⁷

855. EDTI countered that the Commission, in Decision 2014-269, had already stated that it was not prepared to direct EDTI to adopt AltaLink's depreciation methodology without a more in-depth examination of the effects and associated implications of doing so. EDTI submitted that depreciation rates for the Heartland project assets are reasonable and are consistent with EDTI's approved DLM.⁷⁷⁸ EDTI reiterated its position that it would not be "appropriate for EDTI to have different methodologies for the depreciation of assets on its books."⁷⁷⁹

⁷⁷⁶ [Uniform System of Accounts](#) and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities, page 7, paragraph 18 B. "Service lives. Estimated useful Service Lives of depreciable property must be supported by engineering, economic, or other depreciation studies."

⁷⁷⁷ Exhibit 3539-X0194, CCA argument, paragraphs 81-84, PDF pages 27-28 of 42.

⁷⁷⁸ Exhibit 3539-X0193, EDTI argument, paragraphs 618-622, PDF page 247 of 259.

⁷⁷⁹ Exhibit 3539-X0197, EDTI reply argument, paragraph 169, PDF page 63 of 80.

Commission findings

856. The Commission, consistent with Decision 2014-269, considers that adopting AltaLink's depreciation methodology and proposed depreciation parameters from Proceeding 3524, on a placeholder basis without a more in-depth examination of the potential effects on EDTI's depreciation expense and any associated implications, to be premature.

857. The Commission will consider the depreciation methodology and parameters for the Heartland project assets upon receipt of EDTI's depreciation study, to be filed in EDTI's next GTA. The Commission has directed that this study is to include information concerning the expected service lives for transmission lines and towers built to the functional specifications of the then current ISO Rule 502.2.

858. The Commission directs EDTI to continue to determine the 2015-2017 forecast depreciation expense respecting the Heartland project assets using its currently approved DLM of depreciation on a placeholder basis until the prudence of the final capital additions for the Heartland project assets has been determined in Proceeding 3585.

13 Order

859. It is hereby ordered that:

- (1) EPCOR Distribution & Transmission Inc.'s 2015, 2016 and 2017 transmission facility owner tariffs, terms and conditions, and reserve and deferral accounts are approved, subject to the findings, directions and conclusions in this decision.
- (2) EPCOR Distribution & Transmission Inc. is directed to submit a compliance filing on or before January 4, 2016 addressing the Commission's findings and directions in this decision, and correcting the errors and omissions it has discovered or that were identified during the course of this proceeding.
- (3) EPCOR Distribution & Transmission Inc. in its compliance must include a summary of all changes it has made in its compliance filing, as a result of the findings and directions in this decision.

Dated on October 21, 2015.

Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Kay Holgate
Commission Member

(original signed by)

Kate Coolidge
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
EPCOR Distribution & Transmission Inc. (EDTI) Fasken Martineau Dumoulin LLP
ATCO Electric Ltd.
AltaLink Management Ltd. (AltaLink)
Consumers' Coalition of Alberta (CCA)
Independent System Operator
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP

Alberta Utilities Commission Commission panel M. Kolesar, Vice-Chair K. Holgate, Commission Member K. Coolidge, Acting Commission Member Commission staff A. Sabo (Commission counsel) K. Kellgren (Commission counsel) A. Wilson (student-at-law) L. Mullen D. Cherniwchan S. Karim M. Kopp-van Egteren M. McJannet

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
EPCOR Distribution & Transmission Inc. (EDTI) C. Bystrom J. Liteplo	Main company panel J. Baraniecki S. Chaudhary L. Ciocoiu R. McNeil B. Wiles P. Zrobek Debt rate panel Dr. R. Evans Quanta reports panel L. Ciocoiu B. Wiles G. Sheerin W. Snyder Dr. J. Spare J. Widdifield Compensation and escalation panel J. Baraniecki S. Chaudhary R. Resch Dr. D. Ryan
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	R. Retnanandan
Office of the Utilities Consumer Advocate (UCA) T. D. Marriott	R. Bell
Alberta Utilities Commission Commission Panel M. Kolesar, Vice-Chair K. Holgate, Commission Member K. Coolidge, Acting Commission Member Commission Staff A. Sabo (Commission counsel) K. Kellgren (Commission counsel) A. Wilson (student-at-law) L. Mullen D. Cherniwchan S. Karim M. Kopp-van Egteren M. McJannet	

Appendix 3 – Summary of Commission directions

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

1. On that basis, the Commission considers that for the purposes of this decision, EDTI appears to have effectively complied with Direction 16, but directs EDTI to confirm in its compliance filing that it has not made any changes in any comparative analyses to the approved numbers and dollar values from previous decisions with respect to FTE reallocations between O&M and capital costs. The Commission also directs that in future applications, EDTI shall expressly identify and fully explain any changes made in its comparative analyses to the approved numbers and dollar values from previous decisions or, if no such changes have been made, to indicate this in the application. ... Paragraph 23
2. The Commission expects that EDTI's compliance with Direction 31 will be addressed in Proceeding 20692 and in EDTI's compliance filing to that decision. However, the Commission directs EDTI, in its compliance filing to this decision, to recalculate its forecast transmission capital structure, and average cost of capital and transmission return on rate base for 2015, using the Commission-approved debt and equity ratios of 64.0 per cent and 36.0 per cent respectively. In the order section of this decision (Section 13), the Commission has included additional time for EDTI to submit its compliance filing, to allow EDTI the opportunity to include any adjustments to its generic cost of capital for 2013 and 2014 that may arise from the decision in Proceeding 20692. Paragraph 36
3. Given the inconsistency of costs from one year to the next, or from one forecasting period to the next, the Commission considers that a three-year average using the most recent actuals available is sufficient for the purposes of forecasting life cycle projects such as emergency replacement of equipment. The Commission acknowledges that project cost forecasts are uncertain and can differ in any given year due to unforeseen circumstances. The expectation is that the cost forecasts would, on average, be close to the actuals over time, as over-forecasting and under-forecasting are experienced. For all projects that are forecast as a bucket, the Commission directs EDTI to use a three-year average of 2012 to 2014 actuals in its compliance filing to this decision. Paragraph 80
4. With respect to EDTI's operational performance and service quality statistics exceeding those of other transmission utilities in Canada, the Commission recognizes that the comparator SAIFI and SAIDI statistics on the record of the proceeding include both urban and rural utilities, and may not provide an accurate comparison. Nonetheless, the Commission is cognizant that EDTI's SAIFI and SAIDI results exceed the average for other transmission utilities by a significant amount. EDTI is directed to file a comparison of its SAIFI and SAIDI results with those of other urban transmission utilities, to the extent they are available, at the time of its next GTA. Paragraph 82
5. In light of the preceding analysis regarding the relatively constant size of EDTI's system and the historical expenditures on performance improvement projects, the Commission finds that the forecast operating FTE additions for the test period have not been adequately supported. Accordingly, the Commission directs EDTI to reduce the forecast operating FTEs for each of the test years by 2.0 FTEs. Paragraph 145

6. EDTI is directed to use an average cost per FTE of \$130,000 for 2015 and \$140,000 for 2016 and 2017, which results in FTE-related operating cost reductions of \$260,000 for 2015 and \$280,000 for each of 2016 and 2017. EDTI is further directed not to substitute contractor resources or increased overtime for the directed FTE reductions made for the test years, for the purposes of calculating its revenue requirement for the test years, in its compliance filing. EDTI is also directed to provide a schedule identifying where the directed FTE adjustments have been made in the compliance filing. Paragraph 146
7. The Commission directs EDTI in its next application to disregard Direction 6 provided in Decision 2012-272 with respect to the calculation of vacancy rates. Paragraph 161
8. The Commission further directs EDTI to provide an analysis of vacancies and to explain the rationale for its calculations, with specific reference to the treatment of new positions, transfers and “backfilling.” The Commission does not understand how, if new positions are properly reflected in the vacancy calculation, it would be possible to have a negative vacancy rate. Paragraph 162
9. In light of the materiality of Account 560, however, the Commission finds that parties would benefit from additional information on the cost components included in this account. The Commission directs EDTI to provide, as part of future applications, a detailed breakdown of categories and costs included in Account 560, and to separately identify the costs recorded in Account 560 that are not related to O&M in other transmission operating accounts to facilitate consideration of their inclusion and level of cost in this account. Paragraph 185
10. To better understand the possible distortion in compensation or benefits caused by using different comparator groups to assess compensation and benefits, the Commission directs EDTI in its next GTA, if it intends to rely on the BENVAL methodology, to file additional information on the BENVAL results for the subset of the comparator group in the benefits study that corresponds to the companies in the main compensation study, i.e., that are common to both the BENVAL study and the main compensation study. Paragraph 196
11. As an additional matter, the description and details of the BENVAL methodology was not provided on the record of the proceeding. The Commission directs EDTI in future GTAs if it intends to rely on the BENVAL methodology, to provide the details of the methodology in a format similar to the information provided in EDTI’s application in Proceeding 2758, Exhibit 0085.02.EDTI-3758, AUC-EDTI-33(a), Attachment 1 for EDTI’s 2013-2014 TFO application. Paragraph 197
12. The record of the proceeding is unclear as to whether the 3.5 per cent escalation rate proposed for 2015 was inclusive of all labour, merit and step increases. In the compliance filing to this decision, the Commission directs EDTI to confirm whether its proposed escalation rate for non-union employees included all labour, merit and step increases. EDTI is also directed to indicate in its compliance filing, whether its application of the approved escalation rates for non-union employees includes all labour, merit and step increases. Paragraph 220
13. During the course of the proceeding, the collective agreement with the CSU was ratified for the period 2014-2017. For 2015-2017, the Commission finds EDTI’s salary escalation rates agreed to in the new collective agreement for the CSU to be reasonable on a final basis. No placeholder during the forecast period is required, given that the agreement with the CSU was ratified during the course of the proceeding and the actual escalation

- rates are known. In arriving at this finding, the Commission has also considered that the CSU escalation rates for the four years negotiated in the agreement are, on the whole, comparable to the approved escalation rates for non-union employees. Therefore, the Commission approves salary escalation rates for the CSU of 3.16 per cent in 2015, 2.33 per cent in 2016 and 2.23 per cent in 2017. The Commission directs EDTI to reflect the ratified collective agreement CSU employee escalation rates in its compliance filing application to this decision. Paragraph 227
14. With respect to EDTI's assertion that the actual 2014 escalation rate following ratification of the collective agreement should be accounted for on a go-forward basis, the Commission finds that EDTI should account for the actual 2014 escalation rate in calculating its revenue requirement for the test period, in its compliance filing to this decision. In the compliance filing to this decision, EDTI is also directed to explain all of the adjustments to revenue requirement it has included to account for the actual 2014 escalation rate for the CSU agreement. Paragraph 228
 15. However, now that EDTI has some historical information, the Commission considers for comparative purposes it would be useful for EDTI to provide historical information for its allocators of common costs. EDTI is directed to provide in its next GTA, an analysis which compares the utilization of historical and forecast allocators, including a detailed justification as to why a forecast allocator or historically-based allocator provides better information for the allocation of costs for each service. Paragraph 297
 16. Given the lack of operating and capital costing information from distribution, the Commission is not persuaded that there is sufficient information to justify the change in capital overhead and MOP rates forecast for the 2015-2017 test years. As a result, the Commission directs EDTI to revise its forecast MOP rate and capital overhead rates to be consistent with the rates approved in Decision 2014-269, adjusted to include any change associated with the capitalization of STI costs. EDTI, in its compliance filing, is directed to explain any impact to MOP rates and capital overhead rates because of the change in the capitalization of STI costs for the test years. EDTI is also directed to describe the accounting for the STI costs from labour accounts through intermediate overhead accounts to capital accounts. Paragraph 300
 17. Consistent with Decision 2012-237, the onus resides with the applicant to justify its costs included in its GTA. Accordingly, the Commission directs EDTI transmission to file distribution related information in its next GTA to support transmission forecasts. Paragraph 302
 18. Although the Commission recognizes that there may be potential benefits to utility customers arising from the work performed by the corporate development department, the Commission is not persuaded that these costs are directly related to the provision of electric transmission utility service. Further, EDTI failed to quantify and justify any cost reductions that may arise from the growth and diversification of the EPCOR group. For these reasons, EDTI is directed to remove corporate development costs allocated to EDTI transmission in its compliance filing. Paragraph 316
 19. Although the sell-down of EUI's financial interest in Capital Power provides EUI with access to funds that could potentially be used for EDTI transmission, the Commission agrees with the UCA that the sell-down of Capital Power is entirely within the discretion of EUI and its shareholder. EDTI's cost of debt is determined on a stand-alone basis, by which the cost of debt is representative of the cost at which it could have obtained debt in

- the marketplace. Hence, the source of funds loaned to EDTI does not affect the cost of debt to EDTI. EDTI is directed to remove the forecast costs of the Capital Power sell-down from its revenue requirement for the test period, in its compliance filing to this decision. Paragraph 324
20. The Commission is of the view that a decision by business units to transfer from the EPCOR Tower to Rosedale or another location should not necessarily lead to an increase in allocated corporate rent costs, based on a decline in direct assigned costs and utilized space. This view is based, in part, by a lack of clarity in the evidence on the record as to whether the vacated space will be utilized by corporate or another business unit, be vacant during the test period, or leased. The Commission finds that EDTI has not justified why the costs associated with higher corporate rent costs that arise because of underutilized space should be included in revenue requirement. EDTI has failed to explain why these costs are required for the provision of utility service. Accordingly, EDTI transmission is directed to remove from its revenue requirement for the test period the cost increases to EDTI that are attributed to the vacant space and higher corporate rent allocations associated with the 2015 move of EPCOR Water Services Inc. employees from the EPCOR Tower to Rosedale. Paragraph 341
21. The Commission agrees with EDTI that Table 26 above demonstrates cost savings from vacating the EPCOR Tower. However, EDTI has failed to include in the above table and in its work centre redevelopment project business case, a complete assessment of costs that include the resulting higher corporate allocation of rental costs, the savings in direct rent, and the asset usage fee associated with using assets of EDTI distribution. More importantly, the Commission is not satisfied that the costs arising from a lower utilization of EPCOR Tower are required for the provision of utility service. Accordingly, EDTI is directed to remove the increased corporate allocation of EPCOR Tower costs associated with the work centre redevelopment project from its 2016 and 2017 revenue requirement. Paragraph 344
22. For the remaining allocated costs, the Commission finds that the operating costs for 2015-2017 be held to the 2014 rate approved in Decision 2014-269, plus annual adjustment for inflation. The Commission considers that applying inflation to the approved 2014 operating costs is consistent with the range in operating costs (\$15.17-\$19.17 per square foot) that EDTI provided in the Collier's report (2014 Q4). The Commission directs EDTI to adjust its forecast operating costs to the rates approved in 2014 escalated by the inflation rate approved in Section 7.4.4. Paragraph 345
23. Accordingly, the Commission directs EDTI to incorporate the use of a three-year average using 2012-2014 actuals to determine its transmission work for others for inclusion in its 2015-2017 forecast revenue requirement, in the compliance filing to this decision. Paragraph 354
24. Accordingly, EDTI is directed to remove the deferral account true-up respecting the Heartland project from its 2015 forecast and to reflect this amount in its forecast for 2016, in its compliance filing to this decision. Paragraph 367
25. For these reasons, the Commission directs EDTI to reduce its 2015 opening rate base by the amounts reflecting the capitalization of STI costs in 2014. In its compliance filing to this decision, EDTI is to reflect this direction in its actual closing 2014 CWIP balances on a project by project basis, in order to ensure that the 2015 forecast and actual opening rate base will not include any capitalized 2014 STI amounts. Paragraph 399

26. Accordingly, EDTI is directed in its compliance filing, to include a list identifying the projects affected by this direction and the corresponding dollar impacts in 2014. The Commission also directs EDTI to include an updated version of its CWIP continuity schedule reflecting the Commission's direction regarding the capitalization of STI costs in 2014, and an explanation of any corresponding impacts of this direction and any other direction in this decision that affects its CWIP continuity schedule. Paragraph 400
27. However, from the information on the record of this proceeding, it is not apparent whether, and in what amount, any contributions between EDTI and AltaLink are reflected in EDTI's 2015-2017 GTA. Therefore, the Commission directs EDTI in its compliance filing to this decision, to identify the contribution amount, if any, that has been included in the \$268.60 million capital additions recorded by EDTI. Paragraph 402
28. The Commission is concerned that EDTI appears not to have been aware of Permit & Licence Nos. U2012-662 and U2012-663 or Connection Order U2012-671 until mid-2014. The Commission directs EDTI in its next GTA to describe the process used to monitor the status of permits, licences and orders it receives from the Commission. Paragraph 458
29. The Commission directs EDTI to remove all forecast capital expenditures and additions, and related costs with respect to the south central project from its forecast 2015-2017 revenue requirement, and reflect this direction in its compliance filing to this decision. Paragraph 473
30. The Commission directs EDTI to remove all forecast capital expenditures and related costs with respect to the 240-kV GIS substation project from its forecast 2015-2017 revenue requirement, and reflect this direction in its compliance filing to this decision. Paragraph 482
31. The Commission does not, however, give a general approval for this program in future test periods. The rationale for adding additional relay rooms on the basis of capacity constraints, risk of water damage and arc flash risk will be evaluated in future applications on a case-by-case basis for each substation. The Commission, at this time, does not consider that the need for additional relay rooms is sufficient on the basis of the risk of water damage alone, as demonstrated by the infrequent flooding events recorded and the minimal costs associated with those flooding events. The Commission also finds that the arc flash risk associated with the proximity of relay panels to other substation equipment is not sufficiently demonstrated in this application. If EDTI is to rely on concerns regarding the risk of arc flash in future applications, EDTI is directed to provide additional information for relay room additions that demonstrates there is a genuine arc flash risk and that the solution of installing a protective barrier is not feasible or preferable. Paragraph 496
32. On that basis, the Commission directs EDTI to capitalize the applied-for costs of the SEAS reports into a separate regulatory asset account, and amortize the associated costs over a period of five years. Paragraph 520
33. The Commission approves the forecast capital additions for the protective relay and control systems life cycle replacement projects for the purposes of determining EDTI's revenue requirement in the test period. EDTI is directed to include the forecast \$0.10 million increase in project costs on the Woodcroft substation 72-kV breaker failure life cycle replacement project, which was provided in an undertaking to the Commission, in its updated 2015 cost forecast in the compliance filing. Paragraph 559

34. The Commission approves the forecast capital additions for the SCADA system life cycle replacement projects for the purposes of determining EDTI's revenue requirement in the test period. In its compliance filing, EDTI is directed to include the \$0.03 million adjustment identified by EDTI in response to an IR, for the 2016 transducer forecast.
..... Paragraph 566
35. This project category consists of small projects which may be required to bring substation ancillary systems up to safety, environmental or regulatory codes or standards. The business case and application provided no further information regarding what those codes or standards may be, what projects are included in this subcategory, why the projects in this category could not be included in another category of life cycle programs, or why the work required to bring substation ancillary systems up to code is not considered an O&M cost. The Commission acknowledges that the forecast costs are not significant. However, given that the business case for this program provides inadequate justification for the project requirements or costs, the Commission denies the costs in this category for the test years on a forecast basis for the purposes of determining EDTI's revenue requirement during the test period. The Commission directs EDTI to remove the forecast costs associated with this project from its revenue requirement in its compliance filing. Any actual costs incurred in the test period for these projects may be capitalized in EDTI's next tariff application if the Commission is satisfied the expenditures were prudent. .
..... Paragraph 623
36. Based on the foregoing, the Commission does not approve the forecast capital additions and expenditures associated with EDTI's proposed noise mitigation project at the Meadowlark substation for the purposes of determining EDTI's revenue requirement in the test period. The Commission directs EDTI to remove the forecast costs associated with this project from its revenue requirement in its compliance filing. Paragraph 645
37. The Commission is aware of the safety component which defines the need for a fence grounding system. The Commission finds EDTI's proposal to replace the fence bonding connections at all substations to be reasonable in order to prevent emergency repairs or replacements and to prevent harm to EDTI personnel and the public. The Commission approves the forecast capital additions for the substation ancillary system life cycle replacement project for the purposes of determining EDTI's revenue requirement for the test period. However, as EDTI did not identify how substations will be selected each year for fence bonding connection replacement, EDTI is directed to provide this information in its compliance filing and future applications. Paragraph 648
38. Accordingly, the Commission denies the forecast capital additions for these projects for the purposes of determining EDTI's revenue requirement in the test period. The Commission directs EDTI to remove the forecast capital additions and related costs with respect to the Rosedale and Victoria MV switchgear addition projects from its forecast 2015-2017 revenue requirement, in the compliance filing to this decision. . Paragraph 711
39. EDTI stated that the dissolved gas levels in the cable oil have been relatively stable since 2006 due to its maintenance program. There is insufficient evidence to suggest that this maintenance program will not adequately provide for the safe and reliable operation of this cable for the remainder of the test period. In addition the cable is some 35 years old and the Quanta witness confirmed that cables of this type can be expected to last for up to 60 years. Accordingly, the Commission denies the forecast capital additions for this project in the test period for the purposes of determining EDTI's revenue requirement.

- The Commission directs EDTI in its compliance filing, to remove all costs associated with this project from the 2015-2017 revenue requirement. Paragraph 743
40. The Commission notes that EDTI did not propose any changes to its methodology for calculating forecast working capital. The Commission has reviewed EDTI's forecast working capital requirements as set out in Table 38 above and approves EDTI's transmission working capital forecast for 2015 to 2017, subject to any adjustments that may be necessitated by other findings set out in this decision. EDTI is directed to make any necessary adjustments to its working capital calculations to give effect to Commission findings in this decision, in its compliance filing. Paragraph 778
41. The Commission finds EDTI's use of the most recently approved ROE of 8.30 per cent for 2015 on a final basis, and for 2016 and 2017 on an interim basis, to be consistent with the Commission's findings in Decision 2191-D01-2015. The Commission directs EDTI to apply to true-up its ROE for 2016 and 2017 once a decision is issued in the next generic cost of capital proceeding. Paragraph 785
42. The Commission is not satisfied that EDTI has complied with its direction to reflect the findings in the 2013 GCOC decision, as specified in the Commission's May 22, 2015 letter. EDTI is directed to make corrections to the schedules to reflect the approved debt and equity ratios for the year 2015 on a final basis and for the years 2016 and 2017, on an interim basis. The Commission directs EDTI in its compliance filing to this decision, to recalculate its forecast transmission capital structure and average cost of capital and transmission return on rate base for 2015, 2016 and 2017 using the Commission-approved debt and equity ratios of 64.0 per cent and 36.0 per cent, respectively. Paragraph 791
43. As the actual cost of debt for 2015 is known, the Commission approves EDTI's request to reflect its actual cost of debt issued for 2015 of 4.17 per cent in its forecast revenue requirement for 2015, rather than the forecast debt cost of 3.85 per cent or the forward curve debt cost of 3.95 per cent. EDTI is directed to reflect the 4.17 per cent for its 2015 cost of debt in its compliance filing to this decision. Paragraph 823
44. Accordingly, the Commission finds that the 2016 forward curve cost of debt of 4.05 per cent is a reasonable forecast of the cost of debt in 2016. EDTI is directed to reflect the 4.05 per cent cost of debt for 2016 in its compliance filing to this decision. Paragraph 838
45. The Commission approves the forecast cost of debt at the actual cost of 4.17 per cent for 2015 and 4.05 per cent for 2016, for new long-term debt issues, as set out above. EDTI has not forecast a debt issue for 2017, and therefore the Commission does not need to make a determination on the forecast cost of new debt for 2017. For revenue requirement purposes, the Commission directs EDTI to set its embedded cost of debt for 2017 equivalent to its embedded cost of debt including EDTI's approved 2015 and 2016 debt issue costs, as shown in EDTI's schedule of debt capital employed and embedded cost, Schedule 28-2T, and adjusted for the Commission's findings with respect to the 2016 forecast cost of new debt. Paragraph 839
46. The Commission is also satisfied with EDTI's plans to undertake a depreciation study for the purposes of its next tariff application and directs EDTI to conduct and file a depreciation study in its next GTA. The Commission also directs EDTI to conduct and file, as a component of the depreciation study, explicit research and conclusions respecting alternative methods of accounting for the cost of removal of (old) retired assets under the DLM of depreciation beyond EDTI's current practice of capitalizing the

cost of removal at the time a (new) replacement asset is installed and placed into service.

..... Paragraph 852

47. Further, the Commission considers it necessary for EDTI to explore the effects of the ISO Rule 502.2 functional specifications on the estimated useful service lives of EDTI's transmission lines and towers, and to file its findings in EDTI's next GTA. The Commission directs that EDTI include consideration of the estimated useful service lives of EDTI's transmission lines and towers as a component of the aforementioned depreciation study, irrespective of the availability of the revised version of ISO Rule 502.2. EDTI shall refer to the version of ISO Rule 502.2 that was in place at the time the Heartland project was constructed and, should the functional specifications change, file the same information under the new version of ISO Rule 502.2. EDTI is further directed in its consideration of service lives to consider other sources of information respecting estimated useful service lives, such as manufacturer's information, engineering studies or economic studies for the Heartland project lines and towers. Paragraph 853
48. The Commission directs EDTI to continue to determine the 2015-2017 forecast depreciation expense respecting the Heartland project assets using its currently approved DLM of depreciation on a placeholder basis until the prudence of the final capital additions for the Heartland project assets has been determined in Proceeding 3585. Paragraph 858

Appendix 4 – Variance explanations between 2013 and 2014 actual and decision capital expenditures, capital additions and closing CWIP balances

([return to text](#))

Section	Project	2013				2014			Notes
		Opening CWIP	Cap ex	Cap adds	Closing CWIP	Cap ex	Cap adds	Closing CWIP	
9.2.1.2	Genesee - G4/G5 switchyard expansion (direct assigned (DA))	-	-	-	-	0.2	-	0.2	(1)
9.2.1.3	Genesee interface to HVDC converter station (DA)	-	-	1.0	(1.0)	1.3	0.2	0.1	(2)
9.2.1.5	Transformer capacity upgrade - Lambton (DA)	-	0.1	-	0.1	0.6	-	0.7	(3)
9.2.1.6	904L line de-bottlenecking (DA)	-	0.1	(0.6)	0.7	0.1	-	0.8	(4)
9.2.1.7	Heartland 500-kV transmission (DA)	-	30.2	18.2	12.0	16.0	28.0	-	(5)
9.2.1.9	South central transmission reinforcement (Garneau) (DA)	-	(0.1)	-	(0.1)	0.4	-	0.3	(6)
	Subtotal direct assigned projects	-	30.3	18.6	11.7	18.6	28.2	2.1	
9.2.2.1	Protective relaying & control system life cycle (LC) repl and imprv (LC)	-	-	0.2	(0.2)	(0.3)	(0.7)	0.2	(7)
9.2.2.3	SCADA MTU life cycle replacement (LC)	-	(1.4)	-	(1.4)	0.7	(2.2)	1.6	(8)
9.2.2.4	Communication system LC replc and system imprv (LC)	-	(0.5)	(1.1)	0.6	(0.3)	(0.2)	0.5	(9)
9.2.2.7	Circuit breaker replacement (LC)	-	0.2	0.2	-	0.3	0.3	-	(10)
9.2.2.12	500 kV air blast circuit breaker replacement (LC)	-	0.3	0.3	-	0.0	0.0	0.0	(11)
9.2.2.14	Medium voltage switchgear additions - Rosedale	-	(0.2)	-	(0.2)	(2.0)	-	(2.2)	(12)
9.2.2.15	Medium voltage switchgear additions - Victoria	-	-	-	-	(0.4)	-	(0.4)	(13)
9.2.3.1	Life cycle replc of 72-kV T cable splices ... cable sections (LC)	-	(0.1)	(0.1)	-	(0.5)	(0.5)	(0.0)	(14)
9.2.3.2	Life cycle replacement of 240-kV cable sections (LC)	-	(0.4)	-	(0.4)	1.9	3.0	(1.5)	(15)
	Subtotal life cycle projects	-	(2.2)	(0.6)	(1.6)	(0.4)	(0.3)	(1.8)	
9.2.2.18	Communications systems upgrade (performance improvement (PI))	-	(0.5)	(0.3)	(0.2)	(2.3)	(4.2)	1.7	(16)
9.2.2.20	SCADA MTU system security upgrade (PI)	-	0.3	0.3	-	(0.2)	(0.2)	-	(17)
9.2.3.6	System planning load & sustainability study (PI)	-	(0.1)	-	(0.1)	(0.2)	-	(0.3)	(18)
	Subtotal performance improvement projects	-	(0.2)	0.0	(0.3)	(2.7)	(4.4)	1.4	
	All remaining projects	-	(0.2)	(0.1)	0.0	1.5	0.4	1.2	
	All contributions	-	2.3	2.2	0.1	0.3	0.7	(0.3)	(19)

Section	Project	2013				2014			Notes
		Opening CWIP	Cap ex	Cap adds	Closing CWIP	Cap ex	Cap adds	Closing CWIP	
	Total representing actuals higher (lower) than decision	-	30.1	20.1	10.0	17.2	24.7	2.5	
	Total variance after removing Heartland (row 9.2.1.7)	-	(0.2)	1.8	(2.0)	1.2	(3.3)	2.5	

Notes:

- (1) The 2014 costs were related to preliminary work associated with the functional specification, PPS, participant involvement program.
- (2) The 2013 increase in capital additions of \$1 million was due primarily to capitalizing the 138-kV transmission line into service in 2013 as opposed to 2014.
The 2014 increase in capital expenditure of \$1.3 million was related to a \$3.9 purchase of 1203L line from AltaLink offset by cost reductions related to revised routing of lines 430L and 1209L - none of which was contemplated at the time of EDTI's 2013-2014 application.
Source: Exhibit 0003.00.EDTI-3539, application, paragraph 1914; Transcript, Volume 2, page 390.
- (3) The 2014 increase in capital expenditures was related to preliminary work, and progress payments for the two required transformers.
Source: Exhibit 3539-X0005, information response EDTI-AUC-2015FEB06-29.
- (4) The 2013 increase in CWIP was due to EDTI not being able to put their portion of the project into service.
The 2014 increase in expenditures was due to minor grounding, site leveling, gravelling and as-built work that was not anticipated at the time EDTI submitted its 2013-2014 GTA.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 1953-1954.
- (5) The 2013 increase in CWIP and capital additions of \$18.2 million was due to restricted access to the project sites, unseasonable weather which made site access difficult and AC mitigation in addition to delays and failures related to three transformers.
The 2014 increase in CWIP and capital additions of \$28 million is due primarily to AC mitigation costs incurred post energization.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 1962-1963, Exhibit 3539-X0005, information response EDTI-AUC-2015FEB06-31 and Exhibit 3539-X0084, 2014 transmission capital variance - row 2.
- (6) 2014 CWIP and capital expenditures of \$0.4 million include preliminary engineering work, land for new cable at Garneau, PIP, PPS and prep of facility application.
Source: Exhibit 0003.00.EDTI-3539, application, paragraph 1977.
- (7) The 2013 increase in capital additions over the decision amounts was related the effects of Decision 2014-269 and advancing work into 2013, that had been originally scheduled for completion in 2014.
The 2014 decreases in capital expenditures of \$0.3 million and capital additions of \$0.7 million were related mainly to project components being delayed to 2015.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 2026-2029 and Exhibit 3539-X0084, 2014 transmission capital variance - row 4.
- (8) The 2013 decrease in capital expenditures of \$1.4 million was due to the project delay until 2014.
The 2014 decrease in capital additions of \$2.2 million was due to project delays until 2016 related to the timing of the OMS/DMS projects.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 2074-2075 and Exhibit 3539-X0084, 2014 transmission capital variance - row 6.
- (9) The 2013 decrease in capital addition of \$1.09 million was due primarily to project delays related to safety concerns.
The 2014 decrease in capital additions of \$0.2 million was due primarily to completion at lower than forecast costs.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 2113-2114 and Exhibit 3539-X0084, 2014 transmission capital variance - row 7.
- (10) The 2013 increase was related to the bulk oil circuit breaker replacement projects as described in paragraph 6 of T-PIR-03.
The 2014 increase was due to accelerating the replacement of a 72kV air blast circuit breaker in 2014 rather than 2015.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 2166-2167 and Exhibit 3539-X0084, 2014 transmission capital variance - row 10.
- (11) The 2013 increase in capital addition of \$0.3 million was due primarily to higher than expected labour and other costs, and the effects of Decision 2014-269.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 2252-2253.

- (12) The 2013 capital expenditure of \$0.2 million related to feasibility study and preliminary engineering work.
The 2014 capital expenditure decrease of \$2.0 million is related to project delays related to the consultation process.
Source: Exhibit 0003.00.EDTI-3539, application, paragraph 2286.
- (13) The 2014 capital expenditure decrease of \$0.3 million is related to the cost of land being less than forecast.
Source: Transcript, Volume 3, pages 480-481.
- (14) The 2013 decrease in capital expenditures and additions of \$0.1 million related to a decision to not replace 72RS5 cable terminations.
The 2014 decrease in capital expenditures and additions of \$0.5 million related to not completing the 72-kV RW3 splice replacement as scheduled.
Source: Exhibit 0003.00.EDTI-3539, application, paragraph 2414 and Exhibit 3539-X0084, 2014 transmission capital variance – row 24.
- (15) The increase in capital expenditures and 2014 capital additions of \$3.0 million was due primarily to higher contractor costs for carrying out the replacement of cables.
Source: Exhibit 0003.00.EDTI-3539, application, paragraph 2438, and Exhibit 3539-X0084, 2014 transmission capital variance – row 25.
- (16) The 2013 decrease in capital addition of \$0.30 million was due primarily to decreases in contractor and overtime costs related to the installation of a fibre optic cable between the Castle Downs and Victoria substation as described in paragraphs 8 and 9 of T-PIR-05.
The 2014 decrease in capital expenditures and capital additions of \$4.2 million is related primarily to projects not being completed as scheduled.
Source: Exhibit 0003.00.EDTI-3539, application paragraph 2343 and Exhibit 3539-X0084, 2014 transmission capital variance – row 18.
- (17) The 2013 increase in capital additions of \$0.3 million was related to the timing of the capitalization of the project from what was identified and approved in Decision 2014-269.
The 2014 decrease in capital additions of \$0.2 million was related to the timing of the capitalization of the project from what had been identified and approved in Decision 2014-269.
Source: Exhibit 0003.00.EDTI-3539, application, paragraphs 2358-2359 and Exhibit 3539-X0084, 2014 transmission capital variance - row 19.
- (18) The actual 2013 and 2014 costs are related to the preparation of the SEAS report which have been incurred at a cost lower than forecast.
Source: Exhibit 0003.00.EDTI-3539, application, paragraph 2538.
- (19) Within the 2013 increase in capital expenditures and additions was a \$2.2 million contribution adjustment for Poundmaker resulting from a customer contribution decision.
Source: Exhibit 3539-X0005, information response EDTI-AUC-2015FEB06-32.

Appendix 5 – Abbreviations

Abbreviation	Name in full
ABC	Alberta Building Code
ABCB	air blast circuit breaker
AC	alternating current
AESO	Alberta Electric System Operator
AFUDC	allowance for funds used during construction
AHI	asset health index
AIES	Alberta Interconnected Electric System
AltaLink	AltaLink Management Ltd.
ARS	Alberta Reliability Standards
AUC	Alberta Utilities Commission
cap add	capital additions
cap ex	capital expenditures
CCA	Consumers' Coalition of Alberta
CFI	consequence of failure index
CIP	critical infrastructure protection
CPI	Consumer Price Index
CSU	Civic Service Union 52
CWIP	construction work in progress
D&T	distribution & transmission
DA	direct assigned
DACDA	direct assigned capital deferral account
DC	direct current
DFR	digital fault recorder
DGA	dissolved gas analysis
DLM	direct life method
EDTI	EPCOR Distribution & Transmission Inc.
EEA	EPCOR Energy Alberta GP Inc.
EPCOR	EPCOR Group
EPRI	Electric Power Research Institute
EUB or board	Alberta Energy and Utilities Board
EUI	EPCOR Utilities Inc.
FTE	full-time equivalent
G&A	general and administration
GCOC	Generic Cost of Capital decision
GIS	gas insulated switchgear

Abbreviation	Name in full
GOC	government of Canada
GTA	general tariff application
HPFF	high pressure fluid filled
HR	human resources
HV	high voltage
HVAC	heating, ventilation and air conditioning
HVDC	high voltage direct current
IBEW	International Brotherhood of Electrical Workers 1007
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IR	information request
IT	information technology
km	kilometre
kV	kilovolt
LAN	local area network
LC	life cycle
LRT	light rail transit
LTC	load tap changer
MOP	master overhead pool
MRF	minimum filing requirement
MTI	mid-term incentive
MTU	master terminal unit
MV	medium voltage
MW	megawatt
NIA	noise impact assessment
NID	need identification document
NPV	net present value
NWC	necessary working capital
O&M	operating and maintenance
OFPT	oil filled pipe type
OHS	Occupational Health and Safety
OMS/DMS	outage management system/distribution management system
P&C	protection and control
P&L	permit and licence
PBR	performance-based regulation
PI	performance improvement

Abbreviation	Name in full
PILC	paper-insulated lead-case cables
PIR	post-implementation review
POD	point of delivery
ppm	parts per million
PPS	proposal to provide service
PSL	permissible sound levels
PUB	Public Utilities Board
PVC	polyvinyl chloride
Quanta	Quanta Technology, LLC
RFP	request for proposal
RI	risk index
ROE	return on equity
RTU	remote terminal unit
SAIDA	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SCM	supply chain management
SEAS	system planning load and sustainability study and equipment life and condition assessment
SIP	statement of intent to participate
STI	short-term incentive
T&C	terms and conditions
TFO	transmission facility owner
TTC	target total cash: salaries and STI
TTDC	target total direct compensation: TTC plus MIT
TW	Towers Watson
Tx2	power transformer
UCA	Office of the Utilities Consumer Advocate
UofA	University of Alberta
USA	uniform system of accounts
V	volt
XLPE	cross linked polyethylene



ATCO Pipelines

2015-2016 General Rate Application

February 29, 2016

Alberta Utilities Commission

Decision 3577-D01-2016

ATCO Pipelines

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Proceeding 3577

February 29, 2016

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1 Introduction

1. On December 15, 2014, ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., filed an application with the Alberta Utilities Commission requesting approval of its 2015-2016 general rate application (GRA). ATCO Pipelines is requesting approval from the Commission for its forecast revenue requirement of \$214,728,000 for 2015 and \$250,362,000 for 2016. The revenue requirement approved by the Commission will be collected from NOVA Gas Transmission Ltd. (NGTL), as per the terms of integration between the two systems. ATCO Pipelines is also seeking the Commission's approval of ATCO Pipelines':

- forecast opening balances for plant, property and equipment, as at January 1, 2015
- continued use of deferrals and placeholders
- proposed depreciation rate changes
- proposed settlement of certain regulatory deferral accounts

2. On June 22, 2015, ATCO Pipelines filed an updated application revising its forecast revenue requirements for 2015 and 2016, as follows:

Table 1. 2015 and 2016 revenue requirement

2015 revenue requirement	(\$000)
As filed, December 15, 2104	214,728
Reduction	<u>(4,495)</u>
As revised, June 22, 2015	<u>210,233</u>
2016 revenue requirement	
As filed, December 15, 2104	250,362
Reduction	<u>(4,890)</u>
As revised, June 22, 2015	<u>245,472</u>

3. ATCO Pipelines explained that the reduction to its revenue requirements resulted from:

- (1) Decision 2191-D01-2015,¹ 2013 Generic Cost of Capital (GCOC) issued on March 23, 2015 reduced ATCO Pipelines equity ratio from 38 per cent to 37 per cent and the return on equity to 8.30 per cent from 8.75 per cent for 2015 resulting in a forecast revenue

¹ Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.

requirement reduction of \$3.357 million in 2015 and \$4.097 million in 2016 when applying interim placeholders consistent with the decision.

- (2) As indicated in ATCO Pipelines' letter to the Commission dated June 11, 2015, ATCO Pipelines reduced its forecast 2015 and 2016 Urban Pipeline Replacement (UPR) capital expenditures by five per cent to reflect the impact of recent construction costs re-bids. The resulting impact to ATCO Pipelines forecast revenue requirement is a reduction of \$238,000 in 2015 and \$1.029 million in 2016.
- (3) ATCO Pipelines applied reductions to revenue requirement of \$304,000 in 2015 and \$761,000 in 2016 because the House Mountain project was denied by the Commission in Decision 19756-D01-2015,² issued February 19, 2015.
- (4) ATCO Pipelines updated its opening rate base to reflect 2014 actuals, which resulted in an \$877,000 reduction in 2015 and an increase of \$400,000 in 2016. Main drivers of the changes were a higher capital program than originally estimated to the end of 2014 and timing of project in-service dates that were originally forecast to be in service by the end of 2014 but went into service in the beginning of 2015 (Shepard Energy Centre, Sarcee Trail and AC mitigation).
- (5) ATCO Pipelines revised its depreciation expense forecast for 2015 and 2016 to reflect corrections identified in response to AP-AUC-2015FEB03-104 and AP-AUC-2015FEB03-107, which resulted in an increase to forecast revenue requirement of \$342,000 in 2015 and \$463,000 in 2016.
- (6) ATCO Pipelines revised its income tax expense forecast for 2015 and 2016 to reflect the Alberta government's recent announcement of its decision to increase the corporate provincial tax rate to 12 per cent effective July 1, 2015, resulting in an effective tax rate of 11 per cent for 2015 and 12 per cent for 2016. The impact of this adjustment on ATCO Pipelines' 2015-2016 revenue requirement is a net forecast revenue requirement reduction of \$61,000 in 2015 and an increase of \$134,000 in 2016.³

Process

4. The Commission issued notice of the application on December 17, 2014. In response to the notice, statements of intent to participate were filed by the following parties:

- The Office of the Utilities Consumer Advocate (UCA)
- The City of Calgary
- NGTL
- Nexen Energy ULC
- Canadian Association of Petroleum Producers (CAPP)
- Consumers' Coalition of Alberta (CCA)
- Cenovus Energy Inc.
- Encana Corporation

² Decision 19756-D01-2015: ATCO Gas and Pipelines Ltd. (South), Request for Technical Approval to Insert Composite Pipe into Existing House Mountain Transmission Pipeline, Proceeding 19756, Application 1611130-1, February 19, 2015.

³ Exhibit 3577-X0184, ATCO Pipelines updated application, letter to AUC, page 7 of 9.

5. In a letter dated January 16, 2015, the Commission set the process schedule for consideration of the application.
6. On February 18, 2015, ATCO Pipelines filed a submission with the Commission requesting an extension to the filing of responses to information requests (IRs) from February 19, 2015 to March 20, 2015. ATCO Pipelines explained that it required the extension so that it could adequately respond to the large volume of complex IRs.
7. Given the volume of IRs filed, the Commission approved ATCO Pipelines' requested extension, and revised the schedule to the following:

Process step	Deadline date	Revised deadline date
IR responses from ATCO Pipelines	February 19, 2015	March 20, 2015
Intervener evidence	March 5, 2015	April 1, 2015
IRs to interveners	March 19, 2015	April 15, 2015
IR responses from interveners	April 2, 2015	April 29, 2015
Rebuttal evidence	April 13, 2015	May 11, 2015

8. On March 20, 2015, ATCO Pipelines filed responses to IRs from interveners and the Alberta Utilities Commission. Pursuant to sections 9 and 13 of Rule 001: *Rules of Practice*, ATCO Pipelines also requested confidential treatment for IR responses pertaining to:
- documentation from Wipro Solutions Canada Limited (Wipro)
 - a report prepared by KPMG (the KPMG report) and specifically the details related to the supporting price validation
 - the master services agreement (MSA) between the ATCO Utilities and Wipro
 - information related to the Northeast Calgary Connector (a component of the UPR project)
9. On March 25, 2015, the Commission received submissions on the motion for confidential treatment and further process for the proceeding from CAPP, the CCA, Calgary and the UCA. In a March 26, 2015 letter, ATCO Pipelines responded to intervener submissions.
10. On March 30, 2015, the UCA submitted an additional motion to the Commission pursuant to Section 9 of Rule 001 and Section 8 of the *Alberta Utilities Commission Act*, SA 2007, c. A-37.2, for an order that ATCO Pipelines provide full and complete responses to the IRs of the UCA.
11. On April 2, 2015, CAPP, the CCA, Calgary and the UCA provided their comments on the motion for confidential treatment of information responses. ATCO Pipelines provided its reply comments on the motion on April 9, 2015. The Commission also received submissions from parties with respect to the preferred timing of a hearing, second round of IRs, and the sequence for dealing with any motions for better responses to IRs.
12. In a letter dated April 30, 2015, the Commission granted ATCO Pipelines' request for confidentiality and established a second round of IRs.

13. The Commission established the remainder of the process schedule, as follows:

Process step	Revised dates
Filing of confidential undertakings	May 6, 2015
Filing of confidential information by ATCO Pipelines to parties that have filed undertakings	May 11, 2015
Round 2 IRs to ATCO Pipelines	May 21, 2015
ATCO Pipelines responses to Round 2 IRs	June 2, 2015
Intervener motions (if any) on ATCO Pipelines' IRs for further and better responses	June 8, 2015
Intervener evidence	June 15, 2015
IRs on intervener evidence	June 29, 2015
Responses to IRs on intervener evidence	July 10, 2015
Rebuttal evidence	July 20, 2015

14. The Commission determined that an oral hearing would take place in Calgary starting August 10, 2015, with completion tentatively scheduled for August 14, 2015.

15. On May 27, 2015, ATCO Pipelines filed a letter with the Commission requesting an extension to the deadline for filing responses to Round 2 IRs from June 2, 2015 to July 3, 2015. ATCO Pipelines explained that the extension was required because of the volume and complexity of IRs, particularly with respect to information technology (IT) issues.

16. On May 29, 2015, Calgary expressed concern with respect to the regulatory schedule and requested that the process schedule be revised to allow a three-week period for intervener evidence. Alternatively, Calgary suggested that the Commission establish a separate proceeding to examine the prices and term of IT services under the Wipro MSA. Calgary stated that a common proceeding would be more efficient because the same IT issues would also be subject to examination in Proceeding 20272, ATCO Electric Ltd.'s (ATCO Electric Transmission) 2015-2017 general tariff application (GTA).

17. Given the submissions from ATCO Pipelines and Calgary, the Commission, in a letter dated May 29, 2015, suspended the schedule to consider the most effective process to examine IT rates and services with Wipro and set the remainder of the process schedule for this Proceeding 3577.

18. In a letter dated June 2, 2015, the UCA indicated that it would participate in any stand-alone IT proceeding and supported a common hearing on IT pricing. The UCA stated that the existing process schedule did not provide enough time to adequately assess IT matters. Consequently, the UCA submitted that because of ATCO Pipelines' extension request, a new procedural schedule and oral hearing dates were required.

19. In Bulletin 2015-11,⁴ issued on June 4, 2015, the Commission initiated an ATCO Utilities' IT common matters proceeding, Proceeding 20514, to examine prices and term of IT services under the MSAs between the ATCO Utilities (ATCO Pipelines and ATCO Electric

⁴ Bulletin 2015-11, Initiating the ATCO Utilities information technology (IT) common matters proceeding to examine IT costs related to the master services agreements (MSA) between the ATCO Utilities and Wipro Solutions Canada Limited (Wipro), June 4, 2015.

Transmission) and Wipro. Proceeding 20514 was initiated to more effectively address IT matters raised in both Proceeding 3577 and Proceeding 20272, ATCO Electric Transmission's 2015-2017 GTA. In order to facilitate an orderly transfer of relevant information between the proceedings, ATCO Pipelines and ATCO Electric Transmission were directed to refile all IT costs, MSAs (including all responses to IRs related to these issues and any placeholders broken out by operation and maintenance costs), capital expenditures, revenue requirement impact, and forecast IT volumes for the applicable test years.

20. In a letter dated June 5, 2015, the Commission noted that due to the creation of the common matters proceeding for IT costs, a large portion of the responses to Round 2 IRs that related to ATCO Pipelines' May 27, 2015 extension request would now be examined in Proceeding 20514. The Commission recognized that the remainder Round 2 IRs in Proceeding 3577 were also extensive and an extension to filing responses to Round 2 IRs was warranted to allow ATCO Pipelines to respond to Round 2 IRs. The Commission granted ATCO Pipelines an extension for filing responses to Round 2 IRs to June 16, 2015, and issued the following schedule:

Process step	Deadline dates
ATCO Pipelines responses to Round 2 IRs	June 16, 2015
Intervener motions for further and better responses to IRs from ATCO Pipelines	June 23, 2015
Intervener evidence	June 30, 2015
IRs on intervener evidence	July 14, 2015
Responses to IRs on intervener evidence	July 28, 2015
Rebuttal evidence	August 5, 2015
Oral hearing	August 10-14, 2015

21. In its June 5, 2015 letter, the Commission requested that interested parties to Proceeding 3577 file submissions on the reasonableness of the existing hearing dates, the possibility of proceeding with the remainder of the application through a written process, or any other procedural concerns by June 11, 2015.

22. By way of a June 15, 2015 letter, the Commission determined upon review of the comments from interested parties that it would be premature to change the existing schedule and oral hearing. The Commission also set a deadline date of June 23, 2015, for interveners to submit motions on further and better responses to IRs from ATCO Pipelines.

23. On June 22, 2015, ATCO Pipelines filed an update to its application.

24. On June 23, 2015, the Commission received motions from the UCA, Calgary and CAPP. These motions requested that the Commission direct ATCO Pipelines to provide further and better responses to specific information requests. The UCA further requested that the Commission suspend the current process schedule pending resolution of its motion in light of the deadline for filing intervener evidence of June 30, 2015.

25. In a letter dated June 26, 2015, the Commission established a schedule to process the motions filed by interveners and the additional requests of Calgary for filing additional information on the public record of this proceeding.

26. On July 30, 2015, the Commission issued its ruling on the motions. ATCO Pipelines was directed to file further responses to IRs, in accordance with this ruling.

27. The Commission established the following schedule for the remainder of this proceeding and set dates for an oral hearing, as follows:

Process step	Deadline
Filing of further responses, including confidential responses, from ATCO Pipelines	August 10, 2015
Intervener evidence	August 24, 2015
IRs on intervener evidence	September 3, 2015
Response to IRs on intervener evidence	September 18, 2015
ATCO Pipelines rebuttal evidence	October 5, 2015
Oral hearing commences – Calgary	October 13, 2015

28. On October 7, 2015, the Commission received a motion⁵ from the UCA requesting that the Commission either:

- (a) strike the portion of ATCO Pipelines rebuttal evidence which deals with the domestic *Income Tax Act* obligation as it relates to the applied for licence fee, or in the alternative,
- (b) provide parties with sufficient time to consider the new material, obtain advice, retain experts, potentially tender responding evidence and prepare cross-examination for the oral hearing on the new material. The UCA submitted that this may include the option of rescheduling a portion of the hearing or making use of another proceeding where the licence fee is at issue.

29. The UCA objected to the portion of ATCO Pipelines' rebuttal evidence which dealt with the domestic *Income Tax Act* obligations on the basis that this constituted new material and that the material was previously requested in IRs and was not provided.

30. On October 9, 2015, the Commission released its ruling on the UCA's motion stating that certain portions of ATCO Pipelines' rebuttal evidence introduced new evidence on potential domestic tax obligations that may require ATCO Ltd. to charge ATCO Pipelines a licence fee. ATCO Pipelines also introduced new evidence on its interpretation of various sections of the *Income Tax Act* relevant to ATCO subsidiaries in Canada. The Commission found that a separate process was required to allow interveners adequate time to consider the new material and to assess whether additional intervener evidence was required, and for ATCO Pipelines to properly rebut such further evidence. Accordingly, the Commission removed the licence fee issue from Proceeding 3577, and assigned a placeholder of zero dollars to be included in ATCO Pipelines' revenue requirement until a determination is made on the recovery of licence fees.

31. In its ruling, the Commission recognized that ATCO Electric Transmission had proposed a licence fee in its 2015-2017 GTA in Proceeding 20272. As a result, the Commission requested further submissions from parties on the record of this proceeding, by October 22, 2015, on the most effective process and timing to consider the issue of licencing fees.

⁵ Exhibit 3577-X0269, UCA motion re striking new tax evidence.

32. The oral hearing for ATCO Pipelines 2015-2016 GRA was held between October 13, 2015 and October 16, 2015. The Commission set the deadlines for argument and reply argument of November 13, 2015, and November 27, 2015, respectively, which allowed time for the filing of outstanding undertakings and any related interrogatory process.

33. In an October 28, 2015 letter, the Commission reviewed the submissions from parties and considered that the most efficient process to address licence fee costs would be to hold a common licence fee proceeding, which would include an oral hearing. ATCO Electric Transmission and ATCO Pipelines were directed to file a joint licence fee application with the Commission by November 16, 2015, including all evidence and IR responses from ATCO Electric Transmission, ATCO Pipelines and interveners, which were on the record of proceedings 3577 and 20272.

34. In a November 26, 2015 letter, the CCA requested that the Commission suspend the process schedule to allow it to assess any potential impact on the revenue requirement arising from an announcement of recent employee reductions from the ATCO Group.

35. On November 27, 2015, the Commission issued a ruling denying the CCA's request and stated:

3. Given the timing of the close of record of this proceeding and the uncertain effect of the ATCO Group's recent employee reductions on ATCO Pipelines, ATCO Pipelines is directed in its compliance filing to the Commission's pending decision on Proceeding 3577, to clearly identify the impact on FTEs [full-time equivalents] and revenue requirement for the 2015 and 2016 test years because of the recently announced reductions to the ATCO Group workforce. Accordingly, the Commission will establish a placeholder for FTEs and their related costs due to the recent employee reductions to ATCO Group, and these costs will be addressed in ATCO Pipelines' compliance filing.⁶

36. The UCA submitted a motion dated November 30, 2015, requesting the Commission expand placeholder treatment to include all other cost items beyond FTEs because of the recent announcement of ATCO Group employee reductions.

37. On December 2, 2015, the Commission set out a process regarding the UCA's request. In a December 10, 2015 ruling, the Commission denied the UCA's request because the Commission did not consider that an expansion of the placeholders was required. The Commission requested ATCO Pipelines "... to clearly identify the impact on FTEs and revenue requirement for the 2015 and 2016 test years because of the recently announced reductions to the ATCO Group workforce."⁷ The placeholder for FTEs would allow an opportunity for parties to assess the impact of the workforce reductions and revenue requirement impact, while avoiding a rehearing of ATCO Pipelines' forecast costs that were applied for on a prospective basis for broader issues of in-scope/out-of-scope labour, in-line inspection (ILI) work and forecast capital projects.

38. The Commission considers that the record for this proceeding closed on December 10, 2015.

⁶ Exhibit 3577-X0340, Commission's ruling letter, October 27, 2015, paragraph 3.

⁷ Exhibit 3577-X0353, Commission's ruling letter, December 10, paragraph 16.

39. In reaching the determinations contained within this decision, the Commission 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.

2 Background

40. On December 4, 2013, the Commission issued Decision 2013-430⁸ with regard to ATCO Pipelines' 2013-2014 GRA and directed ATCO Pipelines to submit a compliance filing no later than January 22, 2014.

41. ATCO Pipelines filed an application with the Commission on January 22, 2014, requesting approval its 2013-2014 final revenue requirements in its compliance filing to Decision 2013-430.

42. On June 10, 2014, the Commission issued Decision 2014-162,⁹ which approved ATCO Pipelines' final revenue requirements for 2013 and 2014 of \$182.9 million and \$192.6 million, respectively.

43. On March 24, 2015, in Decision 3586-D01-2015,¹⁰ the Commission approved ATCO Pipelines 2015 interim revenue requirement at 60 per cent of ATCO Pipelines' 2015 forecast revenue requirement increase, which resulted in a monthly rate of \$17,157,800 to be collected, effective April 1, 2015. The interim monthly rate remains in effect until another interim rate and/or final rate is approved by the Commission.

3 Discussion of issues

44. Decision 3577-D01-2016 includes a discussion of the contentious cost items forecast in ATCO Pipelines GRA. The Commission has reviewed all remaining forecast costs that were not identified as contentious cost items in the decision and is satisfied that they are reasonable. Any forecast costs, not specifically addressed in the decision, are approved as filed subject to any specific findings contained in this decision.

4 Rate base

45. ATCO Pipelines updated its application on June 22, 2015 with its revised revenue requirements and tables outlining the rate base, plant in service and capital expenditures. ATCO Pipelines requested approval of its forecast revenue requirement of \$210,233,000 for 2015 and

⁸ Decision 2013-430: ATCO Pipelines, 2013-2014 General Rate Application, Proceeding 2322, Application 1609158-1, December 4, 2013.

⁹ Decision 2014-162: ATCO Pipelines, 2013-2014 Revenue Requirement, Compliance Filing to Decision 2013-430, Proceeding 3037, Application 1610269-1, June 10, 2014.

¹⁰ Decision 3586-D01-2015: ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., 2015 Interim Revenue Requirement, Proceeding 3586, Application 1611091-1, March 24, 2015.

\$245,472,000 for 2016. The revenue requirement was based on the rate base provided in the following table:

Table 2. ATCO Pipelines rate base¹¹

		2013 actual	2014 estimate	2015 forecast	2016 forecast
		(\$000)			
01	Mid-year plant in service	843,187	946,052	1,116,419	1,375,186
02	Necessary working capital	28,006	25,421	27,443	29,385
03	Rate base	871,193	971,473	1,143,862	1,404,571

46. The mid-year plant in service was provided in the following table:

Table 3. ATCO Pipelines plant in service at December 31¹²

Line		2013 actual	2014 estimate	2014 adjusted	2015 forecast	2016 forecast
		(\$000)				
01	Property plant and equipment	1,620,627	1,782,282	1,783,060	2,072,037	2,294,363
02	Less: work in progress	79,642	54,822	54,822	81,541	18,684
03	Update - UPR adjustment		(2,407)	(252)		
04	Update - House Mountain adjustment		(500)	(500)		
05	Update - opening balance true-up			38,945		
06	Accumulated depreciation	567,384	589,453	585,551	616,894	652,201
07	Net contributions	92,788	127,217	121,685	125,728	123,639
08	Current year-end balance	880,813	1,011,290	982,557	1,250,281	1,500,091
09	Previous year-end balance	805,561	880,813		982,557	1,250,281
10	TOTAL	1,686,374	1,892,103		2,232,838	2,750,372
11	Mid-year plant in service	843,187	946,052		1,116,419	1,375,186

4.1 Opening rate base

47. In its June 22, 2015 update,¹³ ATCO Pipelines updated its opening rate base for actuals to the end of 2014. The resulting impact on the 2015-2016 forecast revenue requirement is:

¹¹ Exhibit 3577-X0182, ATCO Pipelines updated application, financial schedules, Schedule 2.1-1.

¹² Exhibit 3577-X0182, ATCO Pipelines updated application, financial schedules, Schedule 2.2-1.

¹³ Exhibit 3577-X0184, ATCO Pipelines updated application, letter to AUC, page 6 of 9.

Table 4. Updated opening rate base

2015-2016 revenue requirement Adjustment #4 – 2015 opening rate base	2015 forecast	2016 forecast
	(\$000)	
Dec 31, 2014 net plant, property and equipment adjustment ¹	5,345	
Dec 31, 2014 work in progress timing adjustment ²	(34,078)	-
Opening rate base adjustment	(28,733)	5,345
Dec 31, 2014 work in progress timing adjustment ²	34,078	-
Closing rate base adjustment	5,345	5,345
Revised mid-year rate base	(11,694)	5,345
Rate of return	6.43%	6.43%
Return on rate base	(752)	344
Impact on income tax expense	(125)	56
Net revenue requirement impact	(877)	400

1 Higher capital program than originally estimated to the end of 2014.

2 Mainly due to timing of project in-service dates, consisting primarily of Shepard Energy Centre, Sarcee Trail and AC Mitigation. These projects were originally forecast to be in service by the end of 2014, but were put in service in early 2015.

Commission findings

48. The Commission reviewed the variances between ATCO Pipelines' 2014 actual and approved rate base and is satisfied with the explanations provided by ATCO Pipelines through information responses to IRs. However, the Commission has compared the original 2014 forecast opening property, plant and equipment filed on December 17, 2015,¹⁴ with the corresponding table filed in its June 22, 2015 application update, and it does not appear that the financial schedules align with the adjustment to opening rate base noted above, in Table 4. ATCO Pipelines is therefore directed, in its compliance filing, to review its June 22, 2015 opening rate base adjustments, and all other adjustments it provided in its application update at Exhibit 3577-X0184, and provide the Commission with confirmation that ATCO Pipelines' financial schedules are consistent with revised information reflected in the June 22, 2015 update. ATCO Pipelines is directed to reflect any revisions required to its financial schedules in the compliance filing to this decision.

4.2 Capital expenditures

49. ATCO Pipelines provided the following table showing forecast capital expenditures for the test years and actuals for 2013 and estimates for 2014:

¹⁴ Exhibit 0010.02.ATCOPIPE-3577, ATCO Pipelines financial schedules.

Table 5. Total capital expenditures by category¹⁵

	2013 actual	2014 estimate	2015 forecast	2016 forecast
	(\$000)			
UPR	454	13,687	198,987	138,000
Growth	67,491	73,938	34,822	45,501
Improvements	38,453	52,693	57,474	48,079
Replacements	28,480	26,791	13,692	13,018
Relocations	8,058	11,284	1,120	1,120
IT projects	2,954	3,904	3,899	4,030
Total	145,890	182,297	309,994	249,748
Contributions	24,906	14,975	1,200	1,120

50. Specifically, in its updated application, ATCO Pipelines revised its forecast UPR project capital expenditures to \$198,987,000 in 2015 and \$138,000,000 in 2016, and removed the House Mountain project from the improvements category of capital expenditures.

51. ATCO Pipelines explained that the growth capital expenditures were driven by new NGTL FT-D2 industrial delivery service, which is largely in the Alberta Industrial Heartland area and new FT-D3 utility load growth of the local distribution companies in ATCO Pipelines' footprint driving the need for pipeline facilities. Alberta System Upgrades, the need for which was identified as part of the NGTL planning process for the integrated Alberta System, was mainly due to the Inland Loop Growth project requested by NGTL in the Edmonton area market.

52. The revised expenditures ATCO Pipelines forecast for improvements for 2015 and 2016 are focused on three main areas in its provision of safe, reliable service:

- improvements for pipeline integrity, primarily upgrades to facilitate ILI on existing pipelines
- facility and Salt Cavern gas storage upgrades
- buildings and other improvements

53. The forecast improvement capital expenditures for pipeline integrity related initiatives were outlined in Table 2.3.3-1 and represent nearly 50 per cent of the total improvement forecast in 2015 and over 60 per cent of the forecast in 2016.

54. ATCO Pipelines explained that replacement projects were largely driven by the results of pipeline inspections and directly reflected the value of ATCO Pipelines' pipeline integrity program.

55. The relocation projects are driven by the level of municipal and provincial road authority activity for new roads and highways and other third-party development. Third-party development results in requests for ATCO Pipelines to relocate its facilities and are forecast to be 100 per cent offset by contributions.

56. ATCO Pipelines noted that the IT expenditures to maintain, support and enhance information systems necessary in the provision of safe, reliable service and to facilitate the integration of these systems were included under its asset management system

¹⁵ Exhibit 3577-X0179, ATCO Pipelines updated application, Table 2.3-1, Section 2.3, page 1 of 2.

4.3 Business cases

57. The interveners took issue with the quality of many of ATCO Pipelines' business cases citing deficiencies including the lack of cost-benefit analysis and explanations of need and timing. Both Calgary and the UCA proposed changes to the existing criteria. The concerns raised by the interveners and the responses from ATCO Pipelines with respect to these issues will be reviewed in this section.

58. The UCA adopted Mr. Bell's recommendation that ATCO Pipelines should address the following three issues in the justification of forecast capital project costs for inclusion in rates:

- (i) the utility should demonstrate that, in the absence of the proposed capital expenditures, deterioration in service quality and safety would result;
- (ii) the utility should demonstrate why the project timing is optimal, and that the project could not be deferred to a future GRA;
- (iii) the utility should provide a comparison of the project costs of similar projects over the last five years to the forecasts for each project.¹⁶

59. The UCA noted that Mr. Bell had based this recommendation on criteria developed in the context of performance-based regulation (PBR).¹⁷ Although "these criteria were articulated in PBR and the associated capital tracker context, most of these criteria apply equally in a cost of service context." Mr. Bell asserted that "applying these recommended criteria would: provide transparency and consistency to how the Commission considers capital projects, and "reflect practical approaches and longstanding principles."¹⁸

60. The UCA referred to Decision 3539-D01-2015,¹⁹ wherein the Commission questioned whether imposing additional requirements for business cases could further add to the volume and complexity of the utility's proceedings. The UCA also took note of ATCO Pipelines' rebuttal evidence where ATCO Pipelines claimed that the adoption of Mr. Bell's recommended criteria in the cost-of-service context "would require extra costs as ATCO Pipelines would be required to staff up to provide these type of more extensive analyses."²⁰

61. The UCA argued that adding Mr. Bell's criteria to ATCO Pipelines' business cases was simply a common sense way of getting key relevant information on the record at an early stage in the proceeding resulting in better, not more, effort and potentially increasing the efficiency of the process. Since ATCO Pipelines is in the best position to provide the information relating to these criteria, it should be expected to disclose relevant and probative information in its initial application.²¹

62. Mr. Bell's third criterion, he suggested that a comparison of costs of similar projects over the past five years, reflects an internal calculation any business or sophisticated customer

¹⁶ Exhibit 3577-X0224, R. Bell evidence for UCA, Q23/A23, page 19.

¹⁷ Exhibit 3577-X0224, R. Bell evidence for UCA, Q21/A21, page 14, citing paragraph 1092 of Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

¹⁸ Exhibit 3577-X0333, UCA argument, paragraph 97.

¹⁹ Decision 3539-D01-2015: EPCOR Distribution & Transmission Inc., 2015-2017 Transmission Facility Owner Tariff, Proceeding 3539, Application 1611027-1, October 21, 2015.

²⁰ Exhibit 3577-X0333, UCA argument, paragraph 102.

²¹ Exhibit 3577-X0333. UCA argument, paragraph 103.

undertakes to justify spending. The UCA stated that the current process only discovers this type of context information, if at all, through IRs and cross-examination, and is not an efficient use of resources. As admitted by ATCO Pipelines in cross-examination, that context is useful and helpful to solving problems. Further, Mr. Bell noted in cross-examination that he expected ATCO Pipelines has kept internal records of historical capital expenditures for similar projects as a way of determining whether project costs were reasonable.²²

63. The UCA considered the capital costs proposed to be included in the revenue requirement for the upgrade to the Exshaw Lime Delivery Station was the “poster child” that justified Mr. Bell’s criteria.²³ The UCA pointed out that in its rebuttal evidence ATCO Pipelines stated that, in relation to the Exshaw Lime Delivery Station:

There are in fact multiple issues that have been identified over a period of time... The result of the ongoing issues is increased risks to the provision of safe, reliable service including pressure control devices, gas metering, line heater reliability, and most recently, inoperable isolation valves... Once the inoperable isolation valves were identified, it was determined appropriate to rectify all issues at the stations in facility upgrades. It is most efficient to complete the upgrades in this manner as opposed to piecemeal replacements to address each issue as it arises.²⁴ [underlining by UCA]

64. The UCA considered that ATCO Pipelines provided evidence that, in the absence of the proposed facility upgrade, deterioration in service quality and safety would result; and provided information as to why the project should be completed now i.e., due to “inoperable isolation valves.” However, ATCO Pipelines did not provide any evidence regarding these inoperable isolation valves until pressed in a second round IR.²⁵ There had been no mention of the inoperable isolation valves in the business case for the Exshaw upgrade provided in ATCO Pipelines’ application. Similarly, ATCO Pipelines acknowledged under cross-examination that there was no mention of isolation valves in response to a UCA first round IR.²⁶

65. During cross examination by the UCA’s counsel of the ATCO Pipelines panel, ATCO Pipelines’ witness agreed that the isolation valve issue triggered a “... critical mass of work that made it efficient to proceed [with the Exshaw upgrade] now.”²⁷ This critical mass of information is the sort of thing sought by Mr. Bell’s second criterion about optimal timing. ATCO Pipelines explained what had changed recently to justify moving forward, with a longstanding project, now.²⁸

66. The information that was eventually disclosed satisfied the UCA regarding the need for upgrades at the Exshaw plant and at the Edson OSB Delivery Station.²⁹

67. The UCA argued that the addition of the three criteria to ATCO Pipelines’ business cases would result in a better and more efficient process. Rather than adding cost, volume or complexity to proceedings, as ATCO Pipelines had suggested, the UCA submitted that the additional information provided under these criteria would help address, head on, the issues that

²² Exhibit 3577-X0333, UCA argument, paragraphs 104 and 111.

²³ Exhibit 3577-X0333, UCA argument, paragraph 105.

²⁴ Exhibit 3577-X0265, ATCO Pipelines rebuttal evidence, paragraph 35.

²⁵ Exhibit 3577-X0279, AP-UCA-2015FEB03-022(b).

²⁶ Exhibit 3577-X0333, UCA argument, paragraphs 107-109.

²⁷ Transcript, Volume 3, page 487, lines 4-7.

²⁸ Exhibit 3577-X0333, UCA argument, paragraph 110.

²⁹ Exhibit 3577-X0333, UCA argument, paragraph 110.

ATCO Pipelines' business cases will actually turn on, at an early stage. The UCA maintained that driving ATCO Pipelines to "cut to the chase" when justifying projects may simplify and streamline proceedings.³⁰ The UCA requested that the Commission direct ATCO Pipelines to include Mr. Bell's three additional criteria in its business cases in its next GRA.

68. Calgary argued that ATCO Pipelines had not followed "previous Commission's business case directives or even internal ATCO/ATCO Pipelines business case processes as prescribed in the Wipro MSA, and, therefore, ATCO Pipelines had failed to discharge its onus and recommended that the asset management initiative and Maximo Phase 2 and Hyperion IT projects be disallowed by the Commission."³¹

69. Calgary submitted that it did not make sense for the Commission to allow ATCO Pipelines to follow a lower standard for its regulatory business cases than ATCO or ATCO Pipelines requires from Wipro, its IT supplier, or which ATCO requires internally.

70. Calgary outlined previous Commission business case directives in its evidence and provided its view on the Commission's business case requirements, as follows:³²

The Commission's requires applicants to provide certain information for all major capital projects, in sufficient detail, in rate applications. The Commission's requirements for Business Cases include the following four items:

- i) a detailed justification including demand, energy and supply information;
- ii) a breakdown of the project cost;
- iii) the options considered and their economics; and
- iv) the need for the project.

71. Calgary argued that the Commission regularly considers the benefits, if any, to customers that would result from approving costs applied for by a utility. Proposed projects required justification through a cost-benefit analysis and the perceived benefits to customers should, at least, exceed the costs being passed on to customers. Calgary submitted, "Quite simply, if the costs exceed the benefits, the project should be disallowed."³³

72. Calgary outlined a cost-benefit analysis in its evidence that would meet the Commission's business case requirements. Also, Calgary noted that a number of Commission decisions highlighted the need for a cost-benefit analysis.³⁴

73. Calgary suggested that the Commission disallow the IT capital forecast amounts related to the Geographic Information System (GIS), Pipelines Integrity Management System (PIMS) and Maintenance Management System (MMS) enhancements, due to the absence of business cases.

74. ATCO Pipelines disagreed with both Calgary's and the UCA's arguments that challenged the adequacy of ATCO Pipelines business cases. While Calgary appeared to recognize the traditional criteria applicable to business cases, ATCO Pipelines argued that Calgary placed undue weight on the requirement for a quantitative cost-benefit analysis and incorrectly

³⁰ Exhibit 3577-X0333, UCA argument, paragraph 118.

³¹ Exhibit 3577-X0327, Calgary argument, paragraph 44.

³² Exhibit 3577-X0227, Calgary evidence, Q5/A5, page 4 and Exhibit 3577-X0237, CAL-AUC-2015SEP18-002.

³³ Exhibit 3577-X0327, Calgary argument, paragraph 47.

³⁴ Exhibit 3577-X0227, Calgary evidence, Q6/A6 and Q7/A7, pages 5-6.

concluded that a business case, including a quantitative cost-benefit analysis, was required. In particular, Calgary argued that ATCO Pipelines did not adequately justify, through a cost/benefit analysis, its forecast costs associated with its International Standard for Organization (ISO) 55001 asset management initiative. With regard to the UCA, the UCA improperly proposed the application of entirely new business case criteria. Both Calgary and the UCA appeared to believe the current, traditional business case criteria for ATCO Pipelines were inadequate.

75. ATCO Pipelines submitted that for two decades it had followed the Commission's criteria for major capital projects, as was explicitly set forth in the Alberta Energy and Utilities Board (EUB or board), predecessor to the AUC, in Decision 2000-9:³⁵

The Board has always required, and continues to require, the following information for all major capital projects:

- a detailed justification including demand, energy, and supply information;
- a breakdown of the proposed cost;
- the options considered and their economics; and
- the need for the project.

The Board will expect the information above, provided in sufficient detail, in all future filings.³⁶

76. ATCO Pipelines noted that in its 2013-2014 GRA, the Commission had approved, as filed, 32 capital expenditure business cases. The Commission noted that after reviewing the business cases it found the projects to be warranted and forecast capital expenditures were found to be reasonable.³⁷

77. ATCO Pipelines submitted that the UCA's request for the Commission to impose new business case criteria drawn from the PBR regime was procedurally unfair and failed to consider the specific reasons and context underlying the development of those specific criteria. While ATCO Pipelines acknowledged that certain of the criteria for capital tracker business cases are consistent with ATCO Pipelines' business case requirements, criteria (c), (d), (e), (h), (i) and (j) of the PBR criteria ought not to be applied to the business cases in the current proceeding, or at all. ATCO Pipelines noted that the Commission recently concluded a review of its Rule 020: *Rules Respecting Gas Utility Pipelines*, after inviting comments from stakeholders. Rule 020 addresses, *inter alia*, the information required to demonstrate project need, including both abbreviated and complete need assessments. The UCA did not provide comments in that review.

78. ATCO Pipelines submitted that the Commission recently rejected the application of these same PBR based criteria to business cases for EPCOR Distribution & Transmission Inc. in Decision 3539-D01-2015, where the Commission stated:

745. Mr. Bell pointed to Decision 2013-435 and the 10 criteria for project assessment under capital tracker treatment. Mr. Bell stated that, while several of the criteria were already subsumed in information provided in business cases under cost of

³⁵ Decision 2000-9: Canadian Western Natural Gas Company Limited, 1997 Return on Common Equity and Capital Structure, and 1998 General Rate Application – Phase I, Applications 980413 and 982421, Files 1303-1 and 1304-1, March 2, 2000.

³⁶ Decision 2000-9, page 32.

³⁷ Decision 2013-430, Section. 4.5.3, pages 20-39.

service regulation, significant benefit could be gained if the Commission were to direct EDTI in future GTAs to include the following:

- a demonstration that a deterioration in service quality and safety would result if a proposed capital expenditure did not occur
- a demonstration of why the timing of the proposed capital expenditure is optimal and could not be deferred
- a comparison of similar projects including variance explanations related to both units and costs-per-unit

...

752. The recommendations of Mr. Bell would increase capital project filing requirements beyond what is currently required of utilities, outside of the capital tracker proceedings...

...

754. The Commission is concerned that imposing the additional requirements recommended of Mr. Bell in this case could further add to the volume and complexity of EDTI's GTA proceedings. The Commission is not convinced at this time that the adoption of distribution function capital tracker – type criteria is necessary, given the volume of information on the record of this GTA and the ability of parties to obtain additional specific capital information, should it be required.³⁸

79. ATCO Pipelines argued that to apply such criteria without notice and on an “after the fact” basis was a clear violation of the rules of natural justice and procedural fairness. ATCO Pipelines submitted that the PBR criteria were inappropriate for the ATCO Pipelines system, which remained regulated on a cost-of-service model.

80. ATCO Pipelines submitted that imposing the UCA's proposed PBR criteria on ATCO Pipelines would be entirely inconsistent with Decision 3539-D01-2015.

81. Further, the UCA's suggestion that there are no grounds for distinguishing between criteria developed in the PBR context versus those in the GRA context for ATCO Pipelines is contrary to the UCA's position in the past as noted in Decision 2013-435:

267. Given that capital trackers were expected to be an exceptional feature of PBR plans, the UCA argued that the level of engineering support for a capital project proposed for capital tracker treatment needs to exceed the level of support for capital projects under cost-of-service regulation in order to demonstrate the need for treatment outside of the I-X mechanism. In this regard, the UCA did not agree with the companies' view that a business case analysis of the type filed for capital projects under cost-of-service regulation is sufficient...³⁹

82. ATCO Pipelines submitted Calgary's position represented a direct attack on the business case criteria developed over the years for ATCO Pipelines. Calgary seeks to modify such criteria and its recommendations for disallowances are based on such modifications. ATCO Pipelines considered all of the 60 plus business cases prepared in conjunction with this GRA were in line with the Commission's past requirements.

83. ATCO Pipelines objected to Calgary's attempts to incorporate business case criteria from the Wipro MSA proceeding.⁴⁰ ATCO Pipelines claimed that the business case criteria Calgary

³⁸ Decision 3539-D01-2015, paragraphs 745, 752 and 754.

³⁹ Decision 2013-435, paragraph 267.

⁴⁰ The ATCO Utilities (ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.) Information Technology (IT) Common Matters Proceeding, Proceeding 20514.

selected from the Wipro MSA relate to Wipro business case criteria, and they are not and should not, be equated to the traditional business case criteria developed by the Commission for its GRAs. ATCO Pipelines considered that Calgary's emphasis on quantifiable, cost-benefit criteria, was attempting to recraft the Commission's traditional business case criteria for ATCO Pipelines. ATCO Pipelines' counsel cautioned against using the Wipro MSA as a substitute for ATCO Pipelines' traditional business case criteria.⁴¹

84. ATCO Pipelines argued that both the threshold and level of detail provided in ATCO Pipelines' traditional GRA business case criteria represented a reasonable balance between providing relevant information and the cost, time and effort required to do so. ATCO Pipelines submitted that if the traditional criteria were to be revisited, that it should be done in conjunction with a consideration of all elements of the business cases, including the \$500,000 threshold.⁴²

85. ATCO Pipelines noted that Calgary considered the Hyperion and Maximo Phase 2 business cases deficient based on its application of its new criteria. ATCO Pipelines argued that these business cases were in the same format and provided the same level of information as the business cases that supported the implementation of IT systems, including Maximo Phase 1, in ATCO Pipelines' last GRA. ATCO Pipelines pointed out that neither the Commission, nor any interested party, found the 2013-2014 GRA business cases deficient. ATCO Pipelines submitted that Calgary was seeking to impose its own interpretation of what constitutes appropriate business case criteria, which is an interpretation at odds with how such criteria, as outlined from Decision 2001-97, have been historically applied.⁴³

Commission findings

86. The Commission has considered the positions of the interveners and the applicant regarding changes to the criteria set out in Decision 2000-9, where the EUB found:

The Board reiterates its concern over the manner in which CWNG provided information to both customers and the Board in this proceeding. Stakeholders of CWNG require sufficient detail in their analyses of projects and expenditures. The Board has always required, and continues to require, the following information for all major capital projects:

- a detailed justification including demand, energy, and supply information;
- a breakdown of the proposed cost;
- the options considered and their economics; and
- the need for the project.

The Board will expect the information above, provided in sufficient detail, in all future filings.⁴⁴

87. The Commission must consider what is satisfactory for ATCO Pipelines' business cases given the criteria set out in Decision 2000-9 and the business cases submitted in this proceeding. The Commission considers that the additional criteria recommended by Mr. Bell as a result of PBR capital tracker criteria should not apply to utilities under cost-of-service regulation, including ATCO Pipelines' current application. This finding is consistent with Decision 3539-

⁴¹ Transcript, Volume 2, page 300, line 21 to page 302, line 24.

⁴² Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 137.

⁴³ Exhibit 3577-X0328, ATCO Pipelines argument, paragraph 162.

⁴⁴ Decision 2000-9, page 32.

D01-2015, EPCOR Distribution & Transmission Inc., 2015-2017 Transmission Facility Owner Tariff, where the Commission stated at paragraphs 752-754:

752. The recommendations of Mr. Bell would increase capital project filing requirements beyond what is currently required of utilities, outside of the capital tracker proceedings. As discussed in Decision 2014-269,^[45] EDTI has been provided multiple Commission directions as to what information is considered relevant and necessary for the purposes of examining capital within a GTA and with which EDTI must remain compliant. These information requirements are in addition to what is already mandatory under the MFRs found on the Commission's website.

753. Ultimately, the burden of demonstrating to the Commission that its forecast costs are reasonable rests with the utility. Additionally, it is open to the Commission and interveners to request additional information that is believed to be required in IRs and through cross-examination.

754. The Commission is concerned that imposing the additional requirements recommended of Mr. Bell in this case could further add to the volume and complexity of EDTI's GTA proceedings. The Commission is not convinced at this time that the adoption of distribution function capital tracker – type criteria is necessary, given the volume of information on the record of this GTA and the ability of parties to obtain additional specific capital information, should it be required. [footnotes removed]

88. The Commission continues to be of the view that these statements of the Commission are equally applicable to ATCO Pipelines, and further, the application of capital tracker criteria, previously and currently, proposed by Mr. Bell for assessing ATCO Pipelines' business cases is denied.

89. In addition to the requirements included in Rule 020, as referenced by ATCO Pipelines in this proceeding, the Commission considers that ATCO Pipelines is still required to file business cases for capital projects it proposes for inclusion in revenue requirement. The Commission agrees with the EUB's findings in Decision 2000-9, and with the requirement that information provided in business cases should be of sufficient detail to allow for the testing of the utility's capital projects and the associated expenditures included in a business case.

90. Further, parties have referred to the \$500,000 threshold that applies to ATCO Pipelines, and this threshold was confirmed for ATCO Pipelines' business cases in Decision 2003-100,⁴⁶ as follows:

With regard to the minimum cost threshold requiring ATCO Pipelines to conduct business case analyses, the Board continues to accept ATCO Pipelines' minimum cost threshold for major projects of \$500,000; however, this threshold would not preclude the Board or interveners from requesting ATCO Pipelines to justify or provide better explanations or information in relation to smaller capital expenditures.⁴⁷

⁴⁵ Decision 2014-269: EPCOR Distribution & Transmission Inc., 2013 and 2014 Transmission Facility Owner Tariff, Proceeding 2758, Application 1609817-1, September 18, 2014.

⁴⁶ Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application – Phase I, Application 1292783-1, December 2, 2003.

⁴⁷ Decision 2003-100, page 13.

91. The Commission considers that the information to be provided, as directed in Decision 2000-9, requires further discussion based on submissions on the record. The findings in Decision 2000-9 for Canadian Western Natural Gas are equally applicable to ATCO Pipelines' business cases. Given the unique arrangement of ATCO Pipelines with NGTL, and the fact that the revenue requirement is recovered through NGTL, the Commission is of the view that it would be instructive to provide some further comment on Decision 2000-9 and ATCO Pipelines' business cases.

92. First, with respect to "a detailed justification including demand, energy and supply information," the information in the business cases should include a detailed description of the project, a discussion of the overall requirement for the project, how the project fits into the existing infrastructure and/or operations and any drivers of the project, which may include economics or safety considerations. Where appropriate, a discussion of the demand, energy and supply information should be included.

93. With respect to the second bullet, "a breakdown of the proposed cost," all projects require an estimate of the capital costs that are proposed to be included in the rate base, and the reasons for the proposed expenditures. The costs should be presented for each year the project is under development or construction until it is added to rate base. New operational expenses, if any, should be estimated if the project is put into rate base before the end of the test period.

94. The third bullet relates to "the options considered and their economics" and should describe the options and alternatives examined. For each alternative, any economic considerations should be provided to support the cost-benefit analysis of the preferred alternative, such that it is clear why the preferred alternative is supported i.e. the rationale for the preferred alternative. For example, a comparison of the cumulative net present value of the revenue requirement, also sometimes referred to as cumulative net present value of cost of service, or cumulative NPVCOS, over at least 10 years should be provided as an economic measure in order to assess the alternatives.

95. The fourth bullet, "the need for the project" should include the rationale of need for the project as outlined under Rule 020, but should also include information as to the growth, replacement, improvement, safety, quality of service, or some combination thereof, and the reasonable timing of the project.

96. In this proceeding, the Commission finds that the business cases provided for forecast capital projects lacked relevant information including, for example, the costs for project alternatives. In addition, the impact on operating costs or cost comparisons based on supporting evidence such as engineering evidence, or qualitative considerations, was not provided for certain business cases, including, for example, the Upgrade Fort Saskatchewan South Fractionator, Lloydminster Gate 3 and Looping, Lac Des Arcs Tap and Lateral, and the Homeglen ILI Run.

97. Although ATCO Pipelines' business cases could have included more detailed information justifying their capital expenditures and alternatives, the Commission is not prepared to apply a general reduction to ATCO Pipelines' forecast because of deficient business cases in light of the discussion that follows with respect to specific capital projects and forecasting accuracy.

98. Any forecast capital expenditures that are underpinned by specific business cases that are not addressed in this decision, are approved as filed.

99. The Commission, however, reminds ATCO Pipelines that the onus is on the utility to provide sufficient information in its business cases to support its capital projects which underpin forecast capital expenditures that are to be included in its revenue requirement.

100. With respect to Calgary's submission that the business case requirements should be consistent with those of ATCO or ATCO Pipelines with Wipro, the Commission does not consider that it is necessary to change the criteria to match what is required with respect to the agreements between ATCO and Wipro. The Commission is not prepared to introduce such a standard at this time, solely for ATCO Pipelines.

101. The asset management projects for 2015 and 2016, which include Hyperion, Maximo Phase 2 and enhancements to GIS, PIMS and MMS, are discussed separately in Section 4.5.9 of this decision.

4.4 Capital additions and capital expenditures forecasting accuracy

102. CAPP argued that ATCO Pipelines had not demonstrated the ability to forecast capital expenditures, and hence rate base, with any reasonable accuracy. CAPP submitted that ATCO Pipelines' capital expenditures were \$1.2 million and \$47.4 million greater than the Commission's approved amounts in 2013 and 2014 respectively. CAPP suggested this raised two points:

1. AP's 2015-2016 GRA application did not state that its cash flow or ability to complete capital projects was impacted by the Commission's decision to reduce its allowed Replacement and Improvements expenditures.
2. The aggregate capital originally forecast in 2013-2014 was greater than the actual capital spent in 2013-2014, suggesting to CAPP that AP continues to over-forecast its capital expenditures in relation to those projects put into service.⁴⁸

103. CAPP proposed that the capital expenditures and, hence rate base and all rate-base related costs, be treated on an "actual" or annual deferral account basis.

104. CAPP requested the Commission ensure that ATCO Pipelines' return on equity (ROE) and recovery of operating costs reflect only those assets that are used to provide rate-regulated services during the test years, based on the following three principles:

1. Rate regulated utilities should only earn a return on projects that are used to provide rate-regulated services (i.e. are in-service);
2. Rate regulated utilities should only recover costs directly related to the operation of its system during the test period;
3. The over-forecasting of costs, previously disallowed expenses or expenses not incurred during the test period should be disallowed in the calculation of Placeholders and Deferral accounts.⁴⁹

105. Irrespective of deferral treatment, CAPP did not support ATCO Pipelines earning a return on items that are not in service such as the forecast UPR, Maximo or unspecified general projects until these projects are in service, but accepts their inclusion in deferral accounts. CAPP

⁴⁸ Exhibit 3577-X0326, CAPP argument, page 4.

⁴⁹ Exhibit 3577-X0326, CAPP argument, page 19.

submitted that ATCO Pipelines' request to change definitions, to calculate deferral account or placeholder balances inconsistently and to include expenses or payments that do not relate to the test period, should be disallowed.

106. CAPP disagreed that ATCO Pipelines had a good record of forecasting capital expenditures. In respect of a table, provided by ATCO Pipelines in its argument that purports to demonstrate this forecasting record, CAPP submitted that the table showed the difference between ATCO Pipelines' approved capital expenditures and its actual expenditures. It does not speak to ATCO Pipelines' ability to forecast capital expenditures. CAPP reproduced the table (below) from page 41 of ATCO Pipelines' argument using forecast and actual capital expenditures for 2011-2014. CAPP argued that this revised table illustrated that ATCO Pipelines over-forecast its capital expenditures for this period by \$52.75 million.

107. CAPP's reproduced table of capital expenditures from 2011 to 2014 is set out below:⁵⁰

Table 6. Comparison of actual and forecast capital expenditures from 2011-2014

Capital	2011 ⁽¹⁾	2012 ⁽¹⁾	2013 ^(2/3)	2014 ^(2/3)	Total
Actual	111,782	74,152	145,890	185,918	517,742
Forecast	156,749	80,662	155,747	177,335	570,493
	(44,967)	(6,510)	(9,857)	8,583	(52,751)
	-28.69%	-8.07%	-6.33%	4.84%	-9.25%

(1) AUC Decision 2013-430 (ATCO Pipelines' 2013-2014 GRA), Table 2.

(2) 2013 & 2014 Forecast - AUC 3577 AP-AUC-2015Feb03-20 Attachment 2; page 1/22.

(3) 2013 & 2014 Actual - AUC 3577 AP-AUC-2015Feb03-20 Attachment 1; page 1/21.

108. CAPP observed that not only did ATCO Pipelines significantly over-forecast capital expenditures during the period but it also significantly over-forecast its rate base. As a result, ATCO Pipelines significantly over-earned in 2013 and 2014. ATCO Pipelines' approved rate base was reduced from an even higher ATCO Pipelines forecast rate base that was greater than actual rate base by \$7.63 million in 2013 and \$22.23 million in 2014. ATCO Pipelines' argument that it had improved its forecasts of capital expenditures was not supported by the evidence and was also irrelevant. ATCO Pipelines' earnings are a function of its rate base, not capital expenditures. CAPP proposed to the Commission that the most effective way to manage over-earning based on an inflated rate base was to give all capital expenditures deferral account treatment, only allowing assets into rate base when the specific facilities are actually in service.⁵¹

109. In addition, CAPP provided the following analysis of earnings between 2009 and 2014:⁵²

⁵⁰ Exhibit 3577-X0341, CAPP reply argument, page 3.

⁵¹ Exhibit 3577-X0341, CAPP reply argument, page 4.

⁵² Exhibit 3577-X0326, CAPP argument, page 1.

Table 7. Comparison of approved return on equity versus actual for 2009-2014

Year	2009	2010	2011	2012	2013	2014 estimate	2014 actual ⁽²⁾
	(%)						
Approved equity thickness	43.00	45.00	45.00	38.00	38.00	38.00	37.00
Approved ROE	9.00	9.00	8.75	8.75	8.75	8.75	8.30
Actual ROE	Note 1	10.85	11.53	11.16	10.14	9.83	10.31
Over earning of ROE		1.85	2.78	2.41	1.39	1.08	2.01

Actual ROE values are derived from Rule 005, Schedule 2 unless otherwise noted.

Note 1 - For 2009, ATCO Pipelines was reported as ATCO Pipelines-North (actual ROE = 10.75 per cent) and ATCO Pipelines-South (actual ROE = 11.3 per cent).

Note 2 - Actual 2014 ROE updated from CAPP -1 in IR AUC--4 Attachment 1; page 3/18.

110. The UCA considered that there are three general areas that should be considered in the justification of forecast capital project costs for inclusion in rates. The utility should demonstrate, in the absence of the proposed capital expenditures, that deterioration in service quality and safety would result. The utility should also demonstrate why the project timing is optimal and the utility should provide a comparison of the actual costs of similar projects over the last five years to the forecast costs for each project, together with an explanation for any differences between these amounts.

111. The UCA was also concerned that ATCO Pipelines had over-forecast the amount of work it will be able to do during the test period. On average, over the last four years, customers have paid for 17 per cent more capital in rates than was actually spent.

112. Notably, ATCO Pipelines is forecasting a significant increase in spending for ILI in the test years, despite ILI having been a legal requirement since 2006, according to ATCO Pipelines, and an industry-standard practice for many years before that.

113. The UCA argued that ATCO Pipelines had increased the amount of capital related to ILI from \$358,000 in 2013 and \$4,358,000 in 2014 to \$10,155,000 in 2015, and \$16,470,000 in 2016. Given the history of over-forecasting of capital additions, the fact that ILI is a longstanding practise that ATCO Pipelines has failed to implement, and the increase in spending on ILI in 2015 and 2016, the UCA questioned whether ATCO Pipelines can or will accomplish all of its plans to implement ILI as well as its other capital project work during the test years.⁵³ The UCA recommended that the forecast of capital additions be reduced by 17 per cent to reflect this historical pattern of ATCO Pipelines over-forecasting capital expenditures, and to reflect the ability of ATCO Pipelines to achieve all of its planned capital projects.⁵⁴

114. The UCA asserted ATCO Pipelines had a history of a systemic over-forecasting capital expenditures as demonstrated in the following table of capital additions. Actual capital additions are shown to be lower than forecast in each year:⁵⁵

⁵³ Exhibit 3577-X0224, R. Bell evidence for the UCA, page 23.

⁵⁴ Exhibit 3577-X0333, UCA argument, paragraphs 125-127.

⁵⁵ Exhibit 3577-X0224, R. Bell evidence for UCA, Q26/A26, page 21.

Table 8. Comparison of actual versus approved capital additions from 2011-2014

Capital additions	Reference ⁵⁶	2011	2012	2013	2014	Total
		(\$000)				
Actual	Exhibit 3577-X0056	88,466	70,704	118,786	174,179	452,135
Approved	Exhibit 3577-X0178	136,976	91,002	141,465	176,262	545,705
Variance		(48,510)	(20,298)	(22,679)	(2,083)	(93,570)
%		-35.41%	-22.31%	-16.03%	-1.18%	-17.15%

115. Since ATCO Pipelines did not provide detailed approved capital additions for 2011 and 2012, the UCA submitted that a more detailed analysis of the over-forecasting could not be provided, but it was clear that there was a systematic over-forecasting of capital additions.

116. Approved capital additions were approximately 17 per cent higher than actual capital additions over the years 2011 to 2014. This resulted in \$93 million of capital in rates that was not spent. ATCO Pipelines' forecast capital expenditures for 2015 and 2016, including in relation to ILI, showed substantial escalation when compared to previous years.⁵⁷

117. ATCO Pipelines argued that the UCA's speculation on ATCO Pipelines' ability to implement ILI during the test period, without any expertise on ILI or knowledge of ATCO Pipelines' system or staffing or contracting practices, should be rejected by the Commission. ATCO Pipelines argued that denying ILI funding would send entirely the wrong signal to ATCO Pipelines in the current climate of increased public expectations of pipeline operators.

118. ATCO Pipelines noted the UCA's claims that it had a "... history of over forecasting capital expenditures" but argued that its trending in capital expenditures was the opposite, as evidenced by the table provided below:⁵⁸

Table 9. Comparison of actual versus approved capital expenditures from 2011-2014

Capital expenditures	Reference	2011	2012	2013	2014	Total
		(\$000)				
Actual	Exhibit 3577-X0056	111,782	87,630	146,382	185,105	530,899
Approved	Exhibit 3577-X0178	154,874	82,159	144,684	138,547	520,264
Variance		(43,092)	5,471	1,698	46,558	10,635
% annual		-27.82%	6.66%	1.17%	33.60%	2.04%
3-year % (2012-2014)		14.7%				
2-year % (2013-2014)		17.0%				

119. ATCO Pipelines argued that it was on target with its necessary applied-for capital work for the 2013-2014 test period. As noted in the ATCO Pipelines argument, the UCA based its recommendation for a disallowance of 17 per cent of capital additions on stale data that was used to reduce ATCO Pipelines' costs in the past and on the unwarranted assumption that ATCO Pipelines would not be able to complete its forecast work in the test period.

⁵⁶ Actual from AP-UCA-2015Feb03-010(a) Attachment 27 and approved from AP-UCA-2015May21-078(a) Attachment 28.

⁵⁷ Exhibit 3577-X0333, UCA argument, paragraph 136(f).

⁵⁸ Exhibit 3577-X0328, ATCO Pipelines argument, paragraph 69.

120. ATCO Pipelines disagreed that any capital reduction, let alone an arbitrary, across-the-board reduction, was warranted. As evidenced by the capital expenditures table above, ATCO Pipelines had demonstrated a good record of forecasting capital expenditures. ATCO Pipelines pointed to its actual and forecast capital additions variance, which shows an improving trend, before looking at project circumstances for individual variances.

Commission findings

121. The Commission observes that the UCA places emphasis on capital additions, while ATCO Pipelines argues its position based on capital expenditures. CAPP, on the other hand, would prefer to use actuals and a deferral account method of treatment before capital expenditures are added to rate base.

122. The Commission is of the view that the evidence on the record shows that ATCO Pipelines has a history of over-forecasting capital expenditures in Table 6 and capital additions in Table 8, of 17.15 per cent and 9.25 per cent respectively, over the 2011-2014 period. The Commission finds that an adjustment to forecast capital expenditures is reasonable and will ultimately result in a corresponding reduction to capital additions. However, the Commission considers that the reduction is only warranted for certain categories of capital expenditures.

123. The Commission finds that no adjustments are required to UPR capital expenditures due to the rebids that have occurred during the course of the proceeding and that the UPR amount will be adjusted in the related deferral account. Further, no adjustment is required to growth capital expenditures because these amounts are impacted by the NGTL directed growth capital expenditures deferral account and to the forecast relocation capital expenditures (which are offset by contributions). IT capital projects, in particular, have been considered on a case-by-case basis in Section 4.5.9 of this decision. ATCO Pipelines' applied-for gap analysis related to ISO 55001 certification is addressed in the O&M section of this decision, in Section 6.3.1.

124. The Commission finds that the forecasting accuracy for replacement and improvement capital expenditures appears to have been problematic, as reflected in the data summarized by CAPP, which shows a \$39 million or 10 per cent difference between forecast and actual expenditures over the period studied for the replacement and improvement categories.

125. ATCO Pipelines is directed to reduce its forecast by 10 per cent for replacement and improvement capital expenditures. The Commission considers a 10 per cent reduction is reasonable given the historical information provided by ATCO Pipelines for capital expenditures in this category, and given the forecast work and capital expenditures that are likely to result from capital projects to be undertaken in 2015 and 2016.

126. The Commission also considers that capital expenditures in general are best examined on a forecast, prospective basis. If capital expenditures were entirely subject to deferral accounts, this would not provide an incentive for ATCO Pipelines to manage its forecast capital costs. Accordingly, CAPP's proposed deferral account for capital expenditures is denied.

127. In addition to the Commission's reduction to ATCO Pipelines' 2015-2016 improvements and replacement capital expenditures, the Commission has provided its concerns and findings with respect to specific capital projects in the sections that follow. Capital expenditures related to capital projects for the 2015-2016 test years that are not subject to specific directions in this decision, are approved as filed.

4.5 Capital projects

128. In the section that follows, the Commission includes a discussion of capital projects that were contentious in the proceeding. The Commission has reviewed the information on the record with respect to the capital projects not specifically addressed in this decision, and is satisfied that ATCO Pipelines has justified the need for these projects, and therefore approves the forecast capital expenditures for the test period, as filed.

4.5.1 Urban Pipeline Replacement projects

129. On January 17, 2014, the Commission issued Decision 2014-010⁵⁹ which approved the proposal related to the need for ATCO Pipelines' UPR pipelines. The UPR proposal is comprised of 12 individual pipeline projects, four in Edmonton and eight in Calgary. ATCO Pipelines stated that the need for the UPR project is driven by safety, reliability and future growth considerations. The existing Edmonton and Calgary pipeline systems that ATCO Pipelines proposes to replace with the pipelines that make up the UPR program will either be transferred to ATCO Gas for conversion to distribution use, or abandoned. ATCO Pipelines proposed to complete the UPR project over a period of five years. In Decision 2014-010, the Commission found that ATCO Pipelines had demonstrated a need to relocate the Edmonton and Calgary systems and was satisfied that approval of the UPR proposal is the best alternative to address that need. ATCO Pipelines' UPR application was approved subject to the direction that ATCO Pipelines must advise the Commission of any material changes to the timing or any other aspect of the implementation of the UPR proposal at the time of any related facilities application or at the time of its next GRA, whichever comes first.⁶⁰

130. ATCO Pipelines provided the following table⁶¹ outlining its forecast expenditures for several UPR projects of which some of the capital expenditures were outside the test years:

⁵⁹ Decision 2014-010: ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., Urban Pipeline Replacement Project, Proceeding 1995, Application 1608617-1, January 17, 2014.

⁶⁰ Decision 2014-010, paragraphs 249 and 300.

⁶¹ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 2.3.1, pages 4-5 of 7.

Table 10. Forecast ATCO Pipelines UPR capital expenditures

Description	2013 LTD	2014	2015	2016	2017	2018	Total project
(\$000)							
Edmonton							
Northwest Edmonton Connector	24,951	1,847	-	-	-	-	26,798
Southwest Edmonton Connector	971	5,500	43,362	22,187	542	-	72,562
Northeast Edmonton Connector	-	-	-	4,788	27,864	380	33,032
South Edmonton Connector	-	-	-	-	37,382	5,367	42,749
Calgary							
East Calgary Connector	12,427	930	47,731	1,615	-	-	62,703
Southeast Calgary Connector	8,526	2,701	47,569	1,615	-	-	60,411
Northeast Calgary Connector	6,978	2,709	57,950	6,544	190	-	74,371
Peigan Trail Lateral	-	-	950	34,485	2,850	237	38,522
West Calgary Connector	-	-	1,425	66,766	2,584	-	70,775
Northwest Calgary Connector	-	-	-	-	53,319	1,092	54,411
Southwest Calgary Connector	-	-	-	-	60,800	3,064	63,864
Total capital	53,853	13,687	198,987	138,000	185,531	10,140	600,198

*Costs do not include ATCO Gas costs.

131. On December 19, 2014, ATCO Pipelines provided correspondence in the Northeast Calgary Connector facilities proceeding, and committed to undertaking a rebid of the UPR projects, due to a “sharp reduction in oil prices.” ATCO Pipelines submitted that this was a reasonable response to the dramatic oil price decline and this represented a measured approach to ensuring UPR project costs continued to reflect market pricing, while balancing such concerns against the harm of an undue delay in the implementation of the UPR project.

132. ATCO Pipelines submitted that the rebid confirmed market pricing savings, which was first noticed in the Northeast Calgary Connector rebid and resulted in ATCO Pipelines reducing its UPR project costs by five per cent in its June application update. ATCO Pipelines proposed the use of a deferral account to provide customers any benefit from future tenders in the test period when actual costs are below the original forecast.

133. The CCA was concerned that expenditures to complete the UPR projects have increased dramatically over the estimates provided in the UPR hearing in 2014. The CCA submitted that the total project forecast costs still had a great deal of uncertainty as ATCO Pipelines still had not completed detailed design or costing for the required improvements at the Edmonton Ethane Extraction Plant related to the South Edmonton Connector.

134. The CCA observed that five years after ATCO Pipelines conceived of the UPR and four years after the Northwest Edmonton Connector was installed, prior to the Commission mandating the UPR hearings, ATCO Pipelines still had not completed detailed design and costing for the replacement facilities at the Edmonton Ethane Extraction Plant and finalized the plans for the pipelines that are currently serving it, i.e., Pembina, Swan Hills, Bonnie Glen, and Devon. These pipelines were identified as critical to be removed from high-pressure service. Also, ATCO Gas had not provided costing for the future major gate and distribution infrastructure to support the modifications at the Edmonton Ethane Extraction Plant in its capital

tracker application for 2016-2017 and the ATCO Gas expenditures for this element of UPR were still unknown and not part of the total cost to date.

135. The CCA submitted that even without this critical information from ATCO Gas and detailed costing for ATCO Pipelines' final elements, the projected UPR costs already total \$828 million. The delay in having detailed plans and costing for the referenced projects was even more troubling since the Pembina line was singled out as a line that was not safe for continued operation in its current location in the UPR hearing, yet it was one of the last to be addressed in ATCO Pipelines' UPR schedule. Another area of concern was in the business cases for Northeast Edmonton Connector, Peigan Trail Lateral and the Southwest Calgary Connector, where it was documented that NGTL had not yet confirmed required sizing. The CCA noted that it is a full two years past the UPR application, and final sizing is still not completed, with no update or understanding of the nature, or progress of the discussions between ATCO Pipelines and NGTL related to the long-term supply for Edmonton and Calgary and the UPR sizing criteria.

136. The CCA was also concerned with the lack of transparency related to hydraulic reviews in the UPR process. The documentation provided for the technical justification of each of the connector pipelines was a single sentence acknowledging NGTL's confirmation of the proposed sizing. The CCA submitted that this was inadequate for the justification of projects of this magnitude. The CCA recommended that going forward, detailed hydraulic analysis be required for ATCO Pipeline projects approved by NGTL. The CCA submitted that critical information required to make informed decisions in the public interest had been excluded from the public because of confidentiality between ATCO Pipelines and NGTL. Of particular note were the large cost overruns of the UPR project, combined with ambiguity of actual costs.

137. The CCA submitted that the information provided in the UPR and ILI business cases was insufficient for a thorough public review of proposed expenditures. To best address the public interest, the CCA requested that the Commission direct ATCO Pipelines to provide a complete description of the hydraulic elements of the UPR projects, including pipeline flows in critical scenarios for all high pressure lines and NGTL's long-term plans for sourcing the Edmonton and Calgary UPR systems. ATCO Pipelines should include clear labeled maps showing all of its high pressure assets in the urban areas of Calgary and Edmonton, including high pressure lines that were not part of the UPR plan or discussions. The Alberta Energy Regulator licencing information for all ATCO Pipelines' lines should be included. Additionally, the information should clearly identify all high pressure lines within the city limits of Edmonton and Calgary, and the vintage and normal operating pressures that will remain post-UPR. The CCA asserted that without the requested information it was not possible to provide adequate oversight on these proposed projects.

138. CAPP objected to the inclusion of the Peigan Trail Lateral, West Calgary Connector and the Northeast Edmonton Connector projects in ATCO Pipelines' 2015-2016 revenue requirement, because the scope, the NGTL's hydraulic approvals and detailed engineering were not complete. CAPP argued that the onus was on ATCO Pipelines to submit information that was complete and could be tested for reasonableness. The costs should be disallowed, until the scope of the project was finalized and costs known and could be tested by interveners.⁶²

139. ATCO Pipelines submitted that the Peigan Trail Lateral and the West Calgary Connector projects were slated for construction in 2016, while the Northeast Edmonton Connector was

⁶² Exhibit 3577-X0326, CAPP argument, page 6.

scheduled to be constructed in 2017. ATCO Pipelines included forecast costs to complete the detailed engineering and construction for the Peigan Trail Lateral and the West Calgary Connector projects in the test period. It was common under prospective based regulation to include in test years forecast projects in advance of when they are scheduled to be completed. ATCO Pipelines argued that such was the very nature of prospective ratemaking. To exclude projects from the two-year test period simply because they remain, to some extent, under development was an attack on prospective ratemaking. ATCO Pipelines submitted that it had provided extensive evidence on these projects, and their associated cost forecasts were supported by results from rebids on three other UPR projects.

140. ATCO Pipelines argued that the CCA was referencing evidence from the ATCO Gas capital tracker application in Proceeding 20604 that is not on the record in this proceeding and should be given no weight by the Commission. Also, the CCA was raising issues with respect to components of the UPR project that were not part of the test period but were slated for construction in later years.

141. ATCO Pipelines noted the CCA's concern with the lack of budgeted amounts for the major gate station required at the Edmonton Ethane Extraction Plant, no description of the distribution infrastructure required and no commitment as to whether ATCO Gas will utilize ATCO Pipelines' lines. ATCO Pipelines explained that these facilities were not slated for construction in the test period, and that further, "The high level budgets were developed and presented in this application to ensure transparency of the overall UPR program. However, detailed estimates and business cases for projects outside of the test period will be filed in future GRAs."⁶³

4.5.1.1 UPR deferral account

142. As a result of rebidding three UPR projects and noting that a reduction had occurred, ATCO Pipelines proposed a deferral account, which could be used during the test period to provide customers any benefit from future tenders below the original forecast.

143. The UCA noted that Mr. Bell's evidence specifically identified the deferral account proposed by ATCO Pipelines for the UPR projects as being of concern. He stated:

The decision of when and how to effect the UPR program is ultimately within the control of AP's management. AP should be expected to rigorously administer procurement practices to ensure that its system is developed in the most cost effective manner possible.⁶⁴

144. The UCA fully agreed with the principles that Mr. Bell articulated in his evidence, but took the following position:⁶⁵

... However, based on its evaluation of the full record of the proceeding, including cross examination, at this time and in these circumstances the UCA supports AP's request for deferral account treatment for the UPR project component of 2015-2016 Revenue Requirement. This is despite the fact that Mr. Bell stated that "[t]hese circumstances

⁶³ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 73.

⁶⁴ Exhibit 3577-X0224, R. Bell evidence for UCA, Q32/A32, page 26.

⁶⁵ Exhibit 3577-X0333, UCA argument, paragraph 60.

should not qualify for deferral account treatment” – a statement that the UCA would typically support.

145. CAPP supported the use of a deferral account for UPR projects and other projects in order to mitigate the over-forecasting of projects by ATCO Pipelines that were not in service during the test period.

Commission findings

146. The Commission agrees with ATCO Pipelines that the CCA has focussed some of its comments on projects that are not included in the test years and therefore the Commission has restricted its findings to the UPR projects that are included in the test years.

147. In respect of the Peigan Trail Lateral and the West Calgary Connector, the Commission agrees that it is in keeping with prospective rate making that forecast estimates are necessary for any capital expenditures expected during the test years. Given that prospective rate making is the regulatory model in use for ATCO Pipelines, the Commission is satisfied that ATCO Pipelines has provided reasonable estimates for UPR projects during the test years. In respect of details and other aspects of the various UPR projects yet to be approved, they will be subject to future approval in either a facilities or rates proceedings.

148. The Commission agrees with the CCA that the lack of transparency with respect to the hydraulic analysis, technical justification and the confidential nature of NGTL’s approval for UPR projects is a serious concern. In spite of information that may be confidential, in future general rate applications, the Commission directs ATCO Pipelines to provide more detailed information to support the hydraulic analysis, technical justification and financial justification of its pipeline projects, including NGTL’s rationale for its approvals. The Commission considers that this approach is reasonable because it allows for efficient processing of the current application but acknowledges that further information is required on a go-forward basis. It will also allow ATCO Pipelines the opportunity to consult with NGTL on what information can be disclosed on a public basis, and if there are concerns with confidentiality, ATCO Pipelines can apply to the Commission for confidential treatment of information that may be required to support its revenue requirement with respect to UPR projects or other pipeline projects that may require information from NGTL.

149. The Commission acknowledges the concerns of interveners with the significant increase in capital expenditures that were forecast for the UPR projects. As observed by the UCA, it is of interest that the increases appear to be with contract pricing rather than an increase in the labour or material components of UPR projects.

150. It appears to the Commission that the timing of the tendering may have much to do with the bid prices and re-tendering has provided some price relief, in part due to the economic downturn. ATCO Pipelines reduced its forecast expenditures during the test years by five per cent, and these forecasts are approved as filed. However, given the current economic climate, ATCO Pipelines is directed to provide an update on its efforts to reduce UPR capital costs in the compliance filing, and to provide the actual costs of these projects for the 2015 test year.

151. In light of the above and the nature of the UPR projects that are yet to be completed, the Commission finds that the proposed deferral account for UPR capital expenditures, meets the criteria for deferral account treatment set out in Decision 2003-100:

1. Materiality of the forecast amount.
2. Uncertainty regarding the accuracy and ability to forecast the amount.
3. Whether or not the factors affecting the forecast are beyond the utility's control.
4. Whether or not the utility is typically at risk with respect to the forecast amount.⁶⁶

152. Further, the UPR deferral account appropriately balances the interests of customers and the utility consistent with Commission's finding from Decision 2010-189.⁶⁷

73. In another Board decision, also referenced in Decision 2003-100, the Board, when examining the merits of an application for a deferral account on the facts of that proceeding, took the view that "deferral accounts should not be for the sole benefit of either the company or the customers." Deferral accounts, rather, should "provide a degree of protection to both the Company and the customers from circumstances beyond their control," and hence "[s]ymmetry must exist between costs and benefits for both the Company and its customers." The Board also noted that it expected that "the individual mechanisms involved in the use of each deferral account should be applied in a consistent and fair manner in both test years and non-test years." This will be referred to as the symmetry factor.

74. The deferral accounts proposed in this proceeding will be examined on its overall merits, as the Board and Commission have done in the past on a case-by-case basis. Nonetheless, the Commission considers the four factors plus the symmetry factor as instructive for the purpose of this evaluation.⁶⁸ (footnotes removed)

153. Accordingly, the Commission approves the reduced forecast capital expenditures as provided in the June 2015 application update by ATCO Pipelines. The Commission also approves the proposed UPR deferral account.

4.5.1.2 UPR procurement process

154. On March 20, 2015, the Commission granted confidential treatment for UPR information responses that largely related to ATCO Pipelines' procurement process. As a result, the summary of argument from the UCA and ATCO Pipelines on the UPR procurement process is provided at a high level to ensure the confidential nature of the information on the record is maintained.

155. As noted in Section 7.1 of the application, UPR forecast capital costs have increased from approximately \$369 million to \$600 million over a three-year period.

156. The UCA argued that the competitive bid process did not result in competitive bid pricing despite relatively flat labour and material costs because the bid process timelines were shortened, the number of bidders were too small, the tender process was confusing, and UPR costs were forecast on an incomplete tender process. Further, ATCO Pipelines' standard procurement process was not structured to mitigate cost pressures, and potential bid errors were not corrected.

157. To remedy the UCA's concerns, ATCO Pipelines proposed deferral account treatment, so that parties can test ATCO Pipelines' procurement practices and whether ratepayers will have obtained lower costs as a result of the weakened Alberta economy.

⁶⁶ Decision 2003-100, pages 115-116.

⁶⁷ Decision 2010-189: ATCO Utilities, Pension Common Matters, Proceeding 226, Application 1605254-1, April 30, 2010.

⁶⁸ Decision 2010-189, pages 17-18.

158. ATCO Pipelines argued that the bids received were part of a robust bid process with good depth of qualified bidders. Further, the UPR needs proceeding provided 2011-2012 high-level estimates, and were based on the first UPR constituent project completed before the UPR needs proceeding ‘time-out,’ and came within five per cent of budget. With respect to any bid errors, ATCO Pipelines explained that they could be addressed within the bid review process. In addition, all bidders were afforded a reasonable period to submit their bid, especially given they were in an earlier UPR bid process.

Commission findings

159. The Commission has reviewed the evidence with respect to ATCO Pipelines’ procurement process and is satisfied that the bid process is reasonably competitive and has a sufficient number of qualified bidders. However, the Commission concurs with the UCA that the UPR cost increases are significant and material to customers, from not only a transmission perspective, but also with respect to the timing and future tie-ins with the ATCO Gas distribution system. Given these concerns, the Commission has approved deferral account treatment for UPR capital expenditure in the test years, which will afford interested parties an opportunity to provide submissions on the costs to be recovered related to the UPR procurement process in future applications.

4.5.2 Inland Looping project

160. ATCO Pipelines proposed the construction of the Inland Looping project in the period, which consists of up to 26.7 kilometres (km) of 508 millimetre (mm) pipeline (maximum operating pressure of 8,450 kilopascals) looping the Inland Transmission system from the western end of Norma Transmission (LSD 04-34-53- 18-W4) to the junction of Inland Wye (LSD 01-04-55-20- W4). In consultation with ATCO Pipelines, NGTL has forecast that ATCO Pipelines’ north integrated system will experience a supply shortfall by the winter of 2016-2017, primarily due to a combination of temperature sensitive growth and industrial demand growth in the greater Edmonton area. The Inland Loop pipeline has been selected by NGTL as the optimal project to provide the required incremental capacity. The expected in-service date is November 2016 and the total project cost is estimated at \$52,375,000.

161. In response to AP-AUC-2015FEB03-063(g), ATCO Pipelines explained that NGTL no longer supports the full 26.7 km of Inland looping. NGTL now proposes the original 18 km of Inland Looping in 2016 at an estimated cost of \$40,000,000, and looping two parts of the Pembina system in 2015 and 2016.⁶⁹ The project is still expected to be in -service by November 2016.⁷⁰ Additional looping of the Pembina system is required as a result of a change in forecast supply/demand balance on the integrated Alberta System.

162. As noted in AP-AUC- 2015FEB03-002, ATCO Pipelines anticipates the creation of two discrete growth projects, the Inland Loop project and Pembina Loop. The projects’ need and scope are still being finalized. Therefore, ATCO Pipelines submitted that any revenue requirement impact will be captured in the NGTL directed growth capital deferral account.

163. No intervener objected to ATCO Pipelines’ proposed project.

⁶⁹ Exhibit 3577-X0171, AP-AUC-2015MAY21-020(b).

⁷⁰ Exhibit 3577-X0064, AP-AUC-2015FEB03-063(e) and (g).

Commission findings

164. The Commission notes that the Inland Looping project has been revised into two discrete projects, the Inland Loop project consisting of 18 km of pipeline and the Pembina Loop project. Given ATCO Pipelines' explanation of the change in scope of the Inland Loop project, the Commission approves the inclusion of the Inland Looping project in the NGTL directed growth capital deferral account. The Commission has reviewed the evidence with respect to the need for the project and the related forecast capital costs (or capital expenditures) and is satisfied that they are reasonable. Therefore, the Commission approves the need for the project and related forecast. As a result of the change in scope of this project, ATCO Pipelines is directed in its compliance filing to reflect the updated forecast of \$40 million in the NGTL deferral account and confirm that the Inland Looping and Pembina Loop project pipeline are still expected to be in service by November 2016.

4.5.3 Upgrade 406 mm Viking 3 and 508 mm Viking 4 Transmission

165. ATCO Pipelines is proposing to upgrade the 406 mm Viking 3 and 508 mm Viking 4 transmission lines from the Legal Uncas Interconnect to Edmonton Gate 1, to accommodate ILI. The total project cost is estimated at \$4,750,000.

166. The CCA submitted that the business case for this project was incomplete in that it did not identify the location or specific nature of the upgrades, nor did it indicate the costs associated with individual sites. The business case indicated the ILI site upgrades will terminate at Edmonton Gate 1, which is located within the City of Edmonton. ATCO Pipelines' testimony implied the Viking 3 and 4 lines will terminate at the UPR. The CCA noted that there was no diagram attached to the business case to provide any clarity as to where the lines will terminate. The CCA recommended that the Commission direct ATCO Pipelines to refile its business case for the Viking number 3 and 4 ILI valve assemblies. The business case should identify the specific locations, individual costs of each upgrade, and the long-term plan for Viking 3 and 4 lines regarding their continued location in Edmonton and their relationship to the UPR project.

167. ATCO Pipelines explained that the ILI tools cannot run on the 406 mm Viking 3 and 508 mm Viking 4 transmission pipelines without modification and ILI is required to identify potential locations of pipeline defects. Detailed ILIs will minimize risk of pipeline failure from unidentified defects and ensure the continued reliable operation of the pipelines. The proposed upgrades on the 406 mm Viking 3 and 508 mm Viking 4 pipelines are located within a 23 km segment between the Legal Uncas Interconnect and Edmonton Gate 1.

168. Further, ATCO Pipelines clarified that the 406 mm Viking 3 Transmission was built in 1948 and it is enamel coated seamless steel pipe. The 508 mm Viking 4 Transmission was built in 1974 and is yellow jacket coated double submerged arc welded steel pipe. Coating damage due to soil stress, rocks or backfilling practices, or from tenting at welds may exist. This damage can shield the cathodic protection current used for corrosion control from reaching the metal pipe surface and result in metal loss. Permanent modification of valves assemblies and other pipeline features are needed to allow the passing of an ILI tool so that the pipelines can be inspected with minimal to no disruption in pipeline operation.

Commission findings

169. The Commission is satisfied that ATCO Pipelines has clarified that the lines will terminate at the Edmonton Gate 1 and the maps provided in the UPR proceeding leading to

Decision 2014-010 show the Viking lines ending at Edmonton Gate 1. No further information is required to address the concern raised by the CCA of where the lines will terminate.

170. The Commission has reviewed ATCO Pipelines' proposal and estimate for the upgrades of the Viking 3 and Viking 4 transmission lines provided in the business cases and finds them to be reasonable. Consistent with the Commission's findings in Section 4.3 of this decision, with respect to capital business cases, it is noteworthy that the business case did not provide estimates of the costs related to the alternatives. Details regarding the various sites would have provided greater transparency with respect to the costs associated with the business case. However, the Commission finds that the estimated costs are reasonable for the work to be completed with respect to the upgrades of the Viking 3 and Viking 4 transmission lines.

171. Based on a review of the evidence, the Commission approves the need for the project and related forecast capital costs as filed.

4.5.4 Upgrade 406 mm Pembina Transmission from Thorsby A Receipt to Edmonton Ethane Extraction Plant

172. ATCO Pipelines proposed to upgrade the 406 mm Pembina transmission line to accommodate ILI at an estimated cost of \$2,250,000.

173. The CCA submitted that the business case for the Pembina Transmission Upgrade was unclear. Specifically, it was unclear about which sites were involved, as well as the cost, location, and scope of work for each site, particularly whether or not ATCO Pipelines was including a launcher on the discontinued portion of the Pembina Transmission at the Edmonton Ethane Extraction Plant. A portion of the pipeline was to be discontinued, specifically the Pembina transmission pipeline at the Edmonton Ethane Extraction Plant. The CCA submitted that if the project involved facilities that were part of the UPR project, then they should be indicated as part of UPR to ensure that the scope of the proposed project was understood. The CCA submitted the business case should be resubmitted to clearly identify the scope of the project, and how the project addresses UPR considerations related to the future abandonment of the Pembina line.⁷¹

174. ATCO Pipelines explained that the 219 mm Pembina Lobstick Transmission was built in 1961 and is polyethylene tape coated seamless steel pipe. The 219 mm Pembina Lobstick Loop was built in 1981 and is yellow jacket coated, and is high frequency electric resistance welded steel pipe.

175. ATCO Pipelines stated that it planned to modify three valve assemblies on the 219 mm Pembina Lobstick Transmission and three valve assemblies on the Lobstick Loop from the Lobstick Receipt at LSD 9-17-50-7-W5M to Drayton Valley North Bank Block Valve at LSD 12-33-48-7-W5M, to allow for ILI. ILI tools cannot be run on the 219 mm Pembina Lobstick Transmission and Lobstick Loop pipelines without modification. ILI is required to identify potential location-specific pipeline defects. Detailed ILIs will minimize risk of pipeline failure from unidentified defects and ensure the continued reliable operation of the pipelines.

⁷¹ Exhibit 3577-X0331, CCA argument, paragraphs 18-19.

176. ATCO Pipelines stated that the ILI receiving station on the portion of the line scheduled for abandonment was being used “while it was available to avoid the costs of constructing a new receiving station upstream.”⁷²

Commission findings

177. The Commission is satisfied that ATCO Pipelines has explained that the ILI receiving station is still in use. The Commission notes that the testimony of ATCO Pipelines’ witness was, as follows:

A. MR. RADKE: So just to clarify, the upgrades that are proposed in this business case to make the pipeline piggable are on the section of pipe out of the city while the pipe -- the ILI tool will be received at EEP. The cost of loading a tool into a pipeline is the bulk of running the cost. When you run an ILI tool – having it go extend down the pipeline for a few extra kilometres to receive at another end point doesn't really change anything.

So in this particular case, we're upgrading this pipeline outside of the city so that we can launch that tool through -- run it all the way through and get data before we end up abandoning or transferring part of that Pembina pipeline inside of the city.⁷³

178. Due to the information provided in the business case and the further explanation provided by ATCO Pipelines’ witness in the hearing, the Commission accepts ATCO Pipelines proposal for the Upgrade 406 mm Pembina Transmission project from Thorsby A Receipt to Edmonton Ethane Extraction Plant, and the costs estimates provided in the business case, as reasonable. Therefore, the Commission approves the need for the project and related forecast capital costs, as filed.

179. Consistent with the Commission’s findings in Section 4.3 of this decision, with respect to capital business cases, it is noteworthy that the business case did not provide estimates of the costs related to the alternatives. These details regarding the alternatives would have provided greater transparency with respect to the costs associated with the business case, however, the Commission finds that the estimated costs are reasonable for the work to be completed with respect to the Upgrade 406 mm Pembina Transmission project from Thorsby A Receipt to Edmonton Ethane Extraction Plant.

4.5.5 Upgrade 323 mm Opal Field Transmission from Opal 26-56 Reducer to Redwater Opal Tie-In

180. ATCO Pipelines proposed an upgrade on the 323 mm Opal Field Transmission pipeline that will allow for ILI of a five km segment between Opal 26-56 Reducer and Redwater Opal Tie-In. The total project cost was estimated at \$650,000.

181. ATCO Pipelines explained that the 323 mm Opal Field Transmission was built in 2008 and is fusion bond epoxy electric resistance welded steel pipe. Coating damage due to soil stress, rocks or backfilling practices or from tenting at welds may exist. This damage can shield the cathodic protection current used for corrosion control from reaching the metal pipe surface and result in metal loss. Also, the risk of mechanical damage increases in pipelines in or near urban/industrial areas.

⁷² Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 70.

⁷³ Transcript, Volume 1, page 137, line 20 to page 138, line 8.

182. The UCA was concerned that the business case suggested that a modified valve assembly was required to retrofit a legacy line to enable ILI.

183. The UCA argued that building a piggable system was far from novel in 2008 and that ATCO Pipelines had missed an opportunity to install ILI capability then. Given that it already had teams mobilized to deal with similar issues, as confirmed by counsel for the UCA under cross-examination,⁷⁴ the UCA submitted that ATCO Pipelines was incurring extra costs to advance its ILI program now.

184. While ATCO Pipelines explained to the panel chair during questioning that ATCO Pipelines did not intend to increase its revenue requirement as a result of the revision that was the subject of the facilities application in Proceeding 20682,⁷⁵ the UCA remained concerned that the actual costs of the Opal Field Transmission Pipeline would be included in rate base. The UCA argued that ratepayers should not pay more now when ATCO Pipelines overlooked an opportunity to do this work more cheaply in 2008.

185. The UCA submitted that the amount that is ultimately included in actual rate base should be limited to the cost that would have been incurred had the work been prudently undertaken in 2008, the last time ATCO Pipelines had crews in the area. As a proxy for this amount, the UCA submitted that rate base additions related to the Opal Field Transmission Pipeline should be limited to the forecast costs currently included in the GRA.⁷⁶

186. ATCO Pipelines argued that if the UCA was proposing that the Commission rule in this GRA on actual costs which will be applied for in a future GRA, that is an improper request. There was no evidence before the Commission with respect to actual costs for the Opal project.

187. ATCO Pipelines further argued that the Commission cannot fetter the discretion of future Commission panels. Any review of, and decision with respect to, such costs can only be conducted at such time as ATCO Pipelines applies for their inclusion in rate base.

Commission findings

188. On October 23, 2015, the Commission approved, in Decision 20682-D01-2015,⁷⁷ the related facilities application with respect to this project. In Decision 20682-D0-2015, the estimated costs for the project increased from the business case estimate of \$650,000 to a revised estimate of \$1,200,000 due to additional pipeline construction, permanent road development and costs associated with environmental approvals.⁷⁸

189. With respect to the UCA's concern that the costs may not be accurately reflected due to scope changes for the upgrade to 323 mm Opal Field Transmission from Opal 26-56 Reducer to Redwater Opal Tie-In, the Commission acknowledges this concern as well as ATCO Pipelines' testimony in response to the panel chair, that it will keep its forecast costs at the amount originally proposed in the application. The exchange regarding the Opal project was:

⁷⁴ Transcript, Volume 2, page 372, lines 11-13.

⁷⁵ Transcript, Volume 3, page 685, lines 11-13.

⁷⁶ Exhibit 3577-X0333, UCA argument, paragraph 123.

⁷⁷ Decision 20682-D01-2015: ATCO Gas and Pipelines Ltd. (South), Valve Assembly Relocation for In-Line Inspection in the Redwater Area, Proceeding 20682, Application 20682-A001, October 23, 2015.

⁷⁸ Decision 20682-D01-2015, paragraph 11.

Q. I just have a few questions here. First one may be directed to Mr. Radke. It's on the Opal project. In Proceeding 20682, ATCO Pipelines has amended the project and proposed a new alternative; is that correct?

A. MR. RADKE: That is correct, yes.

Q. Is it ATCO Pipelines' plan to reflect the changes in the forecast costs in the compliance filing to the GRA application?

A. MR. SHARPE: Needed some accounting advice.

No. We wouldn't update for compliance. While that one project has gone up, projects go up and down so we would stay with the original forecast.⁷⁹

190. Because the forecast costs are estimates and ATCO Pipelines is not proposing to increase the forecast costs for the scope change in the project, the Commission considers that it is reasonable that the actual costs for the project be reviewed in ATCO Pipelines' next GRA.

191. Accordingly, the Commission approves the forecast costs for upgrade to 323 mm Opal Field Transmission from Opal 26-56 Reducer to Redwater Opal Tie-In, as filed.

4.5.6 Homeglen pipeline ILI

192. ATCO Pipelines proposed to conduct an ILI of the 95 km long 610 mm diameter Homeglen Transmission pipeline using electro-magnetic acoustic transducer (EMAT) technology to inspect for crack features at a total estimated cost of \$1,800,000.

193. The CCA stated that ATCO Pipelines is proposing to expend \$1.8 million to utilize the same technology and capitalize the expenditure as extending the useful life of the pipeline. The CCA argued that ATCO Pipelines had provided no evidence to revise its previously held position on EMAT in this proceeding, and had provided evidence to the contrary in the UPR proceeding. The CCA submitted that the Commission should disallow any and all costs associated with EMAT inspections, until evidence is filed to validate this technology.

194. ATCO Pipelines explained that a crack detection tool run, EMAT, is required to inspect the entire length of the pipeline, as magnetic flux technology was unable to effectively detect cracking in order to ensure the continued reliable operation of the Homeglen pipeline. Stress corrosion cracking was found at 15 of the 16 excavations with an average of one crack colony per meter of inspected pipe.

195. ATCO Pipelines considered the inspection necessary as the Homeglen Transmission pipeline was built in stages between 1974 and 1978 and has polyethylene tape coating. Tape coating is prone to damage due to soil stress, low temperature limits, poor application and inherent functional flaws, which leads to corrosion damage and stress corrosion cracking susceptibility.

196. In reply to the CCA, ATCO Pipelines noted that the CCA did not sponsor any evidence on pipeline integrity to support its position. ATCO Pipelines explained that while it had recognized in the UPR proceeding that EMAT was an emerging technology and did not replace

⁷⁹ Transcript, Volume 3, page 685, line 17 to page 686, line 4.

the need for hydro testing in Class 3 and 4 areas, it is not to say that it is not useful in providing certain information in the right circumstances, as ATCO Pipelines confirmed in testimony⁸⁰

Commission findings

197. The Commission approves the forecast ILI capital expenditures and the underlying need to inspect the Homeglen Transmission pipeline, as filed. ATCO Pipelines has provided sufficient support for the requirement for this capital project due to the leaks found on excavations and the location of the pipe. Mr. Sharpe, on behalf of ATCO Pipelines in response to cross-examination, stated:

A. MR. SHARPE: I believe -- so through the UPR proceeding, we did talk about EMAT a fair bit. And EMAT gives you another indication of the condition of the pipeline. Our perspective and -- is that EMAT, while it gives you more indications on the pipeline cannot be strictly relied upon to say that there is no cracks on the pipeline. You would have to do hydro testing.

So EMAT will give you more information on the line and particularly on Homeglen, where it runs through the Class 1, 2 areas. EMAT can give you -- the EMAT tool can and will give more indications of areas you shall look. I would not personally say that you should rely on EMAT as your only tool and in particularly in high consequence areas.⁸¹

198. However, it is noteworthy that the business case was lacking cost estimates related to the alternatives and further information would have assisted the Commission with respect to this project.

199. The Commission also notes the business case indicated the project was to be completed in 2014 but an IR response stated it would not be completed until the second quarter of 2015. The Commission acknowledges the updated time frame for completion of the Homeglen ILI.

4.5.7 Hydrogen sulphide (H₂S) warning lights at 45 stations

200. ATCO Pipelines forecast \$685,000 in 2015 and \$330,000 in 2016 for the installation of a standard H₂S warning light and horn system at 45 stations that could potentially receive natural gas containing H₂S.

201. The CCA submitted that ATCO Pipelines' business case had not confirmed the contractual status of any of the 45 receipt stations. In addition they incorrectly included eight facilities that are part of the asset swap with NGTL.

202. The CCA submitted that a thorough review had not taken place. Furthermore, the CCA submitted that ATCO Pipelines had not fully considered contractual status of facilities prior to including their costs in this application. ATCO Pipelines also confirmed that there are five dually connected receipt stations, where the producer has ability to deliver to both ATCO Pipelines and NGTL. The CCA believed these facilities have not had their contractual status verified prior to inclusion in the business case, nor was a joint review of the necessity of both receipt stations completed. As such, the CCA did not support their inclusion in this application as they represent a significant and ongoing cost to consumers.

⁸⁰ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 79.

⁸¹ Transcript, Volume 1, page 157, line 17 to page 158, line 6.

203. ATCO Pipelines argued that it had explained in its business case, IR responses and in testimony, the safety benefits for both ATCO Pipelines and the public of upgrading ATCO Pipelines' on-site H₂S warning systems to a consistent standard, one that includes an audible warning capability that is currently not available.

Commission findings

204. ATCO Pipelines provided the following responses to the CCA's counsel in respect of the five dually connected and eight NGTL swap related stations:

A. MR. SHARPE: All the stations are flowing. I don't know the specifics of the contract status for each station, but none of the stations are shut in or not flowing that we would undertake this work at.

Q. MR. WACHOWICH: Okay. Will they all be flowing at the end of the UPR?

A. MR. SHARPE: I would expect they would be, yes. But I don't know that for sure.

Q. MR. WACHOWICH: Let me come at it this way, sir: Has NGTL been involved in any review of the list of the 45 receipt stations?

A. MR. SCHMIDT: I would just say that we now operate under the NGTL tariff, which includes gas specifications. And if the receipts exceed those requirements, the producers would be shut-in. This is just providing a consistent set of warning equipment at all our sites, this project.

Q. MR. WACHOWICH: And, sir, my question was more to the direction of whether NOVA may have plans that one of the receipt stations is not going to be needed in the near future and ATCO Pipelines would be investing capital in a warning system, which may not have a full life, if I can describe it that way, because the station may become redundant or otherwise out of service?

A. MR. RADKE: So as with any upgrade -- and not just specific that this specific project -- but any improvement or replacement work at an ongoing facility, we always conduct a review to ensure that that facility is going to be required in the future. So that would be a part of the design process of this project to consult with either the customer or NGTL on that front.⁸²

205. The Commission accepts ATCO Pipelines' business case and efforts to provide adequate H₂S warning systems but finds that ATCO Pipelines did not directly address the CCA's concerns respecting disclosure of the dually connected and NGTL swap stations that require H₂S warning systems. It is clear from the quoted testimony above that there is some doubt as to the need for all of the of the stations to be upgraded in the test years. The Commission is not prepared to accept the forecast capital expenditures in their entirety because there is insufficient confirmation that all 45 stations included in the business case will be required in the test years.

206. For these reasons, the Commission reduces the forecast estimate by the average cost to upgrade eight stations, which results in a disallowance of \$180,444 (i.e. \$1,015,000 / 45 x 8 = \$180,444) split equally between both test years. The Commission directs ATCO Pipelines to

⁸² Transcript, Volume 1, page 141, line 2 to page 142, line 7.

reflect this reduction to its capital expenditures for the H₂S warning lights at its stations, in the compliance filing to this decision.

4.5.8 Edmonton office expansion

207. ATCO Pipelines proposed to construct an expansion to its existing ATCO Pipelines Edmonton Centre (APEC) on property owned by ATCO Pipelines at 7210 – 42 Street. The expansion will add approximately 75 workstations in 19,400 ft² to accommodate the increased number of Edmonton based permanent office employees. The total cost of the project is estimated at \$8,500,000.

208. ATCO Pipelines explained in the business case that the expanded facility:

... would provide 75 additional workstations, which would return the density per workstation to an acceptable level, permit the reinstatement of conference rooms, reduce ATCO Pipelines' need to lease off-site space, and provide employees with a sufficient level of common space such as washroom facilities, lunchroom, coffee stations, central records storage, and space for common printers and photocopiers. The expansion will include a tie-in to the existing APEC facility; permitting Edmonton based employees to remain centralized at the same location.⁸³

209. ATCO Pipelines calculated the 40-year cumulative NPVCOS for the expansion alternative to be \$8,225,000 compared with the 40-year cumulative NPVCOS for a lease alternative as \$12,743,000, assuming a lease escalation factor of five per cent every five years when the lease is renewed.

210. The CCA requested that the Commission reject the proposed building expansion. The CCA also requested that any future space requirements be evaluated upon the completion of UPR, the asset swap with NGTL and the ILI valve assembly program. The CCA considered that ATCO Pipelines reliance on a significant but unquantified number of positions, related to capital programs and succession planning for the company demographics, made long-term staffing forecasts not reliable.

211. The CCA disagreed with ATCO Pipelines' applied-for future staffing requirements, which rely upon a 40-year comparison. The CCA considered a 40-year period was too long to predict the need for additional staff.

212. The CCA suggested that the Commission should give no weight to the statement that FTEs have been ramped up to support UPR. Given the significant changes in staffing that were not disclosed during the hearing process, the CCA submitted that ATCO Pipelines should be directed to file updated schedules of overhead which is capitalized. These schedules should show how the amount of overhead which is capitalized is derived.⁸⁴

213. In addition, the CCA submitted that ATCO Pipelines should be directed to provide an updated forecast of office space needs for its expected FTEs in the compliance filing.⁸⁵

214. ATCO Pipelines argued that contrary to the CCA's assertion, the increase in internal resources in the test period related to ongoing positions will be required post UPR. ATCO

⁸³ Exhibit 0002.00.ATCOPIPE-3577, 7.2 Attachment – business cases, PDF page 71.

⁸⁴ Exhibit 3577-X0342, CCA reply argument, paragraph 17.

⁸⁵ Exhibit 3577-X0342, CCA reply argument, paragraph 19.

Pipelines explained how 23 of the total 46 net additional FTEs in the test period are required on an ongoing basis to support succession planning and ongoing capital programs, including ongoing ILI related work. ATCO Pipelines explained that the remaining 23 net additional FTEs are required to support ongoing operations work related to increased regulatory oversight, increased public safety requirements and asset management.⁸⁶

Commission findings

215. The Commission accepts that the Edmonton office expansion will improve the density per work station and provide space for other office requirements at the same time keeping the staff centralized. The Commission also accepts that building an addition provides a lower cost of service than the costs of leasing equivalent space. However, given the announced employee reductions, the Commission is mindful that the FTE forecasts may no longer support the additional office space for additional personnel at this time.

216. Therefore, ATCO Pipelines is directed to file an update to the Edmonton office expansion business case in the compliance filing to this decision, and the update of FTE requirements. ATCO Pipelines is directed to maintain the capital estimate of \$8.5 million for the office expansion as a placeholder.

4.5.9 Asset management projects

217. Throughout the GRA proceeding, ATCO Pipelines emphasized that managing assets is a foundation of its business and has been since ATCO Pipelines began installing assets. Managing assets touches many parts of ATCO Pipelines' business. The 2015 and 2016 projects that are related to asset management include Hyperion, Maximo Phase 2 and enhancements to GIS, PIMS and MMS.

4.5.9.1 Maximo Phase 2

218. ATCO Pipelines explained that Phase 2 of Maximo will commence in 2016 and is forecast to be completed in 2017 at a total cost of \$1,250,000. A business case in the application was provided in support of the project, which is intended to add the following capability:

- Track leaks and hazard IDs, surface lease payments, water crossings inspections, and third-party inspections and pipeline crossings;
- Automate time entry;
- Increase the type of assets tracked (e.g. fleet);
- Increase the groups using Maximo.⁸⁷

219. ATCO Pipelines stated that the original project to implement Maximo has been a success and encompasses key above ground assets on the pipeline system. The main business drivers of implementing Maximo were:

- To provide the ability to audit records that have been entered into the system;

⁸⁶ Exhibit 3577-X0328, ATCO Pipelines argument, paragraphs 106 and 109.

⁸⁷ Exhibit 0002.00.ATCOPIPE-3577, (Maximo – Information System Enhancements), page 119.

- To provide the ability to ensure that maintenance activities can be tracked and verified as completed to meet both internal requirements and external regulatory requirements;
- Implementing Maximo eliminated the need to upgrade other small systems in place at the time that were not compliant with Windows 7;
- Implementing leading COTS (commercial off the shelf) software.⁸⁸

220. ATCO Pipelines argued that the Maximo solution is intended to be the enterprise-wide central repository for pipeline and facility maintenance data. This will enable management to better budget and estimate resources required to ensure that maintenance activities are completed within their planned maintenance schedules.

4.5.9.2 Hyperion

221. ATCO Pipelines' business case proposed to:

... implement a Hyperion based Budgeting and Planning system to support ATCO Pipelines capital budgeting and forecasting, operating and maintenance (O&M) budgeting and planning. The system will be used to provide four major functions: the production of annual business plans and forecasts; the development of regulatory applications; the production of the monthly current forecast; and modeling and simulation capabilities through the use of multiple scenarios to perform what-if analysis.⁸⁹

222. The total cost of the project was estimated at \$1,600,000, with ongoing costs estimated to be approximately \$150,000 annually.

223. ATCO Pipelines explained that it currently utilizes Excel based financial models to support its short-term financial budgeting and longer-term planning and forecasting requirements. ATCO Pipelines stated that these models and the supporting processes have been developed and modified over a number of years and now rely on in excess of 100 spreadsheets to achieve the level of consolidation and sophistication in forecasting and modeling required by ATCO Pipelines. This "system" is both labour intensive and highly dependent on user knowledge and experience.

224. ATCO Pipelines made the following comments on what would occur if the project were not to proceed:

The risk of not proceeding is primarily in the adverse impacts caused by human error in working with manual processes managing multiple versions of a multitude of spreadsheets. The current Excel spreadsheets are used for the production of annual business plans and forecasts; the development of regulatory applications; reflect impact of regulatory decisions; and the production of the monthly current forecast. Errors in regulatory applications will impact ATCO Pipeline's earnings and reputation due to the over or under stating revenue requirements.⁹⁰

225. ATCO Pipelines stated that the expected benefits of the new system will be to reduce the risks in the current process and streamline the current planning, budgeting and forecasting processes in ATCO Pipelines. Expected key benefits are accuracy, timeliness, flexibility,

⁸⁸ Exhibit 0002.00.ATCOPIPE-3577, (Maximo – Information System Enhancements), page 119.

⁸⁹ Exhibit 0002.00.ATCOPIPE-3577, (Capital and O&M Budgeting, Planning and Forecasting System), page 114.

⁹⁰ Exhibit 0002.00.ATCOPIPE-3577, (Capital and O&M Budgeting, Planning and Forecasting System), page 117.

responsiveness, version control, authorization, security, better training, efficiency improvements and reduced cost overruns.

4.5.9.3 GIS, PIMS and MMS

226. ATCO Pipelines submitted that in order to perform necessary integrity and risk analysis of the high pressure network, there was an increasing requirement for orderly, effective organization and storage of an increasingly larger set of pipeline and related asset data as well as associated operating performance data. ATCO Pipelines stated that this drives the need for expenditures in key IT systems during the test period, including GIS, PIMS and MMS.

227. ATCO Pipelines noted that given that these projects did not exceed the Commission's \$500,000 threshold for business cases therefore this level of detail was later provided to the Commission through information requests. ATCO Pipelines submitted that the information demonstrated ATCO Pipelines' level of commitment to ongoing review and improvement of its existing IT applications in order to manage data with increased effectiveness and efficiency. ATCO Pipelines elaborated generally on its IT systems and emphasized that enhancements for these systems scheduled for the test period are required independent of the ISO 55001 initiative.

228. ATCO Pipelines noted that the forecast expenditures related to Information Systems were \$3.35 million over the test period relate to Maximo Phase 2 and enhancements to GIS, PIMS and MMS. ATCO Pipelines emphasised that these were enhancements to systems that were currently in use. ATCO Pipelines identified the forecast expenditures to enhance these systems as part of its asset management activities. However, it is critical to understand that these enhancements will be required independent of the ISO 55001 initiative. The forecast expenditures of \$3.35 million related to these systems stand on their own merits.

229. Calgary indicated that ATCO Pipelines' proposed "asset management" expenditures were approximately \$5.0 million. Calgary provided a table summarizing the expenditures for three FTEs, asset management consultants and for the following information systems: Maximo Phase 2 and system enhancements to GIS, PIMS and MMS.⁹¹

230. Calgary considered that the forecast expenditures planned by ATCO Pipelines to support its asset management proposal were not supported by quantification of any benefits. Calgary noted that although ATCO Pipelines had provided business cases for both Hyperion and Maximo Phase 2, both were inadequate and neither case had included any quantified benefits.

231. In particular, with respect to Hyperion, Calgary considered the lack of quantified support for the claim that Hyperion would minimize potential error, shorten budget cycles and perform "what-if" analysis and improve productivity to reduce overtime, was reason enough to deny including the proposed \$1.6 million in capital expenditures during the test period.

232. Similarly, with respect to Maximo Phase 2, ATCO Pipelines' claims of efficiency gains were not supported by a cost-benefit analysis. Calgary submitted that without quantification of the benefits there was no justification to approve the \$0.75 million expenditure during the test period.

⁹¹ Exhibit 3577-X0227, Calgary evidence, Q10/A10, pages 8-9.

233. Calgary recommended that the Commission disallow \$4.95 million in forecast IT project capital costs that are in support of ATCO Pipelines' asset management proposal for the 2015-2016 test years made up of the following:

- (i) Maximo Phase 2 – \$0.75 million;
- (ii) GIS, PIMS, MMS for data and system enhancements – \$2.6 million;
- (iii) Hyperion – \$1.6 million.⁹²

234. The CCA observed that ATCO Pipelines had provided, in response to AP-AUC-2015FEB03-029(a), a list of general capital projects. Included were three system enhancements projects including GIS, PIMS and MMS. Each of the costs for these three projects was divided between 2015 and 2016, with each year's expenditures below \$500,000. The CCA took exception to ATCO Pipelines' apparent practice to break-up projects, or phases of projects, to avoid their consideration in a larger business case. As such, the CCA submitted that the three system enhancements projects should be excluded from rate base as ATCO Pipelines had failed to properly document the need for these projects in order to allow for an adequate regulatory review. Business cases should have been provided for the three projects.⁹³

235. ATCO Pipelines submitted that the Hyperion and Maximo Phase 2 business cases were not deficient. ATCO Pipelines argued that these business cases were in the same format and provided the same level of information as the business cases that supported the implementation of IT systems, including Maximo Phase 1, in the last GRA.⁹⁴

236. ATCO Pipelines stated it had indicated in AP-UCA-2015FEB03-039, that IT capital project expenditures in the category IT Projects – General consist of IT projects less than \$500,000 and typically include enhancements to existing systems. Further details of general IT project costs were provided in the attachment to AP-AUC-2015FEB03-029(a). ATCO Pipelines stated that these costs were made up of discrete projects within each year, with each project having a set or defined scope costing less than \$500,000 for the purpose of improving or enhancing the functionality or usability of a software application, whose need had already been approved.

237. ATCO Pipelines stated that it had provided detailed information, through its business cases, on IT capital projects forecast to cost \$500,000 or more. ATCO Pipelines submitted that this was the Commission's traditional threshold for business cases set over a decade ago. It represented a materiality test in the provision of detailed information, intended to balance the effort and time required to supply information against the significance of the costs involved. It is not in the interests of regulatory efficiency to expend excessive time and money on providing detailed information on every dollar of forecast costs.

238. ATCO Pipelines considered that "CCA's assertion that ATCO Pipelines was "breaking up smaller [likely meant larger] projects to circumvent the \$500,000 threshold is without merit and should be summarily rejected by the Commission."⁹⁵ The projects in question are discrete, smaller projects. ATCO Pipelines noted that the Commission had directly addressed the issue of when projects are considered discrete for business case purposes in the last GRA.

⁹² Exhibit 3577-X0227, Calgary evidence, Q36/A36, pages 25-26.

⁹³ Exhibit 3577-X0331, CCA argument, paragraphs 48-49.

⁹⁴ Exhibit 3577-X0328, ATCO Pipelines argument, paragraph 162.

⁹⁵ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 85.

Commission findings

239. The Commission has reviewed the response to AP-AUC-2015FEB03-029(a) and is of the view that the GIS, PIMS and MMS enhancements are not insignificant, given the total amount of the forecast capital expenditures for these IT projects in 2015 and 2016. While ATCO Pipelines stated that each of these projects is discrete, they are all related to improving ATCO Pipelines' asset management and each have a forecast expenditure totaling \$900,000 during the test years. The Commission agrees with interveners that a more detailed explanation of the GIS, PIMS and MMS enhancements is required. While these expenditures are less than \$500,000 on an individual year basis for each project, the cumulative effect of these projects could be significant within the test period and going-forward.

240. In respect of both Hyperion and Maximo Phase 2, the Commission agrees with Calgary that ATCO Pipelines has failed to adequately quantify any benefits associated with the significant capital costs of both projects. Based on the evidence filed in this proceeding, the Commission finds that the Hyperion and Maximo Phase 2 forecast capital expenditures are not adequately justified. The total forecast project costs for Maximo Phase 2 were \$1,250,000 and Hyperion total project costs were estimated at \$1,600,000, with ongoing costs for Hyperion estimated to be approximately \$150,000 annually. While there may be benefits associated with the implementation of these IT projects, the business cases did not provide sufficient information for the Commission to weigh the expected benefits against the forecast costs associated with these projects.

241. Accordingly, the costs for the above IT projects are denied. ATCO Pipelines is directed to remove the capital expenditures totaling \$4.95 million from the test years.

4.6 NGTL/ATCO Pipelines asset transfer

242. ATCO Pipelines and NGTL are both owners and operators of natural gas transmission assets in Alberta. On October 1, 2011, ATCO Pipelines implemented integration with NGTL on a commercial basis. The remaining step to integration is the exchange of assets so that ATCO Pipelines and NGTL will own and operate assets within their respective areas. The exchange of assets (asset swap) was approved in principle by the Commission in Decision 2010-228⁹⁶ and by the National Energy Board (NEB) in Decision RHW-1-2010 and then subsequently approved by the Commission in Decision 2012-310⁹⁷ and by the NEB on October 16, 2014.⁹⁸ The NEB issued a Certificate of Public Convenience and Necessity, CPCN Order GC-123, on December 16, 2014.⁹⁹

243. ATCO Pipelines is transferring 393 pipeline segments totaling 1,249 km in length and is receiving 171 pipeline segments totaling 1,440 km in length. ATCO Pipelines will acquire 85 net¹⁰⁰ new meter stations and will transfer one compressor station.¹⁰¹ The tentative asset swap schedule and a summary of assets to be exchanged are provided in the table below:

⁹⁶ Decision 2010-228: ATCO Pipelines, 2010-2012 Revenue Requirement Settlement and Alberta System Integration, Proceeding 223, Application 1605226-1, May 27, 2010.

⁹⁷ Decision 2012-310: ATCO Gas and Pipelines Ltd., Asset Swap Application, Proceeding 1723, Application 1608166-1, November 22, 2012.

⁹⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.7, page 1 of 3.

⁹⁹ Exhibit 3577-X0279, AP-UCA-2015FEB03-021(a).

¹⁰⁰ Per AP-AUC-2015MAY21-005(b) in Exhibit 3577-X0161, ATCO Pipelines is gaining 115 additional stations and losing 30 stations as result of the asset swap which nets out to a gain of 85 stations.

Table 11. Tentative asset swap schedule and summary of asset types to be exchanged

Event	Timing	ATCO Pipelines assets to NGTL	NGTL assets to ATCO Pipelines
AUC decision on AP's asset swap application	November 22, 2012		
NEB decision on NGTL's asset transfer application	October 16, 2014		
CPCN issued	December 16, 2014		
Completion of Tranche 1 transfer	Q3 2015	87 pipe segments, 14 meter station, 1 compressor station	8 pipe segments, 9 meter stations
Completion of Tranche 2 transfer	Q1 2016	141 pipe segments, 6 meter stations	65 pipe segments, 51 meter stations
Completion of Tranche 3 transfer	Q3 2016	110 pipe segments, 1 meter station	35 pipe segments, 15 meter stations
Completion of Tranche 4 transfer	Q4 2016	55 pipe segments, 9 meter stations	63 pipe segments, 40 meter stations
Monetary adjustment for net book value differences	Q1 2017		

244. The transitional operating agreement¹⁰² outlines the process by which the exchange of assets will occur and the swap will occur in four tranches. The ownership of the assets in each tranche will be transferred at the closing date for each tranche and the assets will be transferred at their net book values, which will result in a forecast monetary adjustment of \$1.2 million to ATCO Pipelines.¹⁰³ The monetary adjustment is expected to have a negligible impact on ATCO Pipelines' 2016 revenue requirement because the intent is that assets of equivalent values will be exchanged between ATCO Pipelines and NGTL.¹⁰⁴ As such, ATCO Pipelines has included zero dollar placeholders in the application for any potential revenue requirement impact resulting from any difference in net book values of the assets exchanged between NGTL and ATCO Pipelines at the completion of the fourth tranche. Any true-up of these zero placeholders will be captured in the NGTL integration deferral account.¹⁰⁵

245. At the conclusion of each tranche of the transfer, non-monetary adjustments will be booked by both ATCO Pipelines and NGTL related to the NGTL-ATCO Pipelines asset transfers. The final net book value difference will be settled via monetary adjustments. The non-monetary adjustment will be reflected as an adjustment to net plant, property and equipment in ATCO Pipelines' financial statements with the offset booked as a regulatory asset/liability. For international financial reporting standards purposes, this regulatory asset/liability will be booked as an adjustment to publicly reported net income.¹⁰⁶

246. The asset swap results in a change to ATCO Pipelines' annual O&M expenses and some one-time capital and expenses. These are set out in the table below:¹⁰⁷

¹⁰¹ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.7, page 3 of 3.

¹⁰² Filed in this proceeding in Exhibit 3577-X0061, AP-AUC-2015FEB03-018(c) Attachment 1.

¹⁰³ Exhibit 3577-X0283, AP-UCA-2015FEB03-057(c) Attachment. Derived from net book value of transferred assets as at December 31, 2012 (ATCO assets transferring to NGTL) – (NGTL assets transferring to ATCO).

¹⁰⁴ Exhibit 3577-X0283, AP-UCA-2015FEB03-057(c).

¹⁰⁵ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.7, pages 2-3 of 3.

¹⁰⁶ Exhibit 3577-X0033, AP-CCA-2015FEB03-003(a)-(b).

¹⁰⁷ This information was provided in response to AUC Direction 10 from Decision 2013-430.

Table 12. Estimated costs and savings from integration 2010-2016

	2010 actual	2011 actual	2012 actual	2013 actual	2014 estimate	2015 forecast	2016 forecast	Total
	(\$000)							
One time capital								
SCADA ¹	-	-	-	-	-	2,020	480	2,500
Signage	-	-	-	-	-	75	100	175
Total capital	-	-	-	-	-	2,095	580	2,675
<i>Capital revenue requirement</i>	-	-	-	-	-	377	481	858
One time O&M								
Mapping						150	50	200
Land (assignment/transfers)	-	578	469	5	20	500	400	1,972
Records management	-	-	-	-	-	100	50	150
Property tax – consultant	-	-	-	-	-	30	120	150
Fixed asset transfers – consultant	-	-	-	-	-	123	30	153
Employee severance	-	105	45	-	-	-	-	150
Legal	396	631	75	8	102	-	-	1,212
Total one time O&M	396	1,314	589	13	122	903	650	3,987
Annual O&M								
Reduced labour costs	-	(679)	(3,128)	(3,128)	(3,128)	(3,128)	(3,128)	(16,319)
Office space	-	(48)	(198)	(198)	(200)	(200)	(200)	(1,044)
IT/Phone	-	(21)	(96)	(96)	(100)	(100)	(100)	(513)
STAR system	-	0	(300)	(700)	(700)	(700)	(700)	(3,100)
Gas Alberta service agreement	-	(64)	(385)	(385)	(385)	(385)	(385)	(1,989)
Misc. (i.e., travel, training)	-	(24)	(100)	(100)	(100)	(100)	(100)	(524)
Total annual O&M	-	(836)	(4,207)	(4,607)	(4,613)	(4,613)	(4,613)	(23,489)
Annual cost of capital	-	-	(3,150)	(3,150)	(3,150)	(3,150)	(3,150)	(15,750)
Annual cost (savings)	396	478	(6,768)	(7,744)	(7,641)	(6,483)	(6,632)	(34,394)
Cumulative costs (savings)	396	874	(5,894)	(13,638)	(21,279)	(27,762)	(27,911)	

Source: Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 6.1 Attachment 4, Table 1.

Note 1: Supervisory control and data acquisition.

247. ATCO Pipelines noted that this analysis does not include ATCO Pipelines' costs that are offset by NGTL savings which results in no net effect on the Alberta system cost of service.¹⁰⁸

248. The one time O&M costs for the property tax consultant and fixed asset transfers consultant are required to process the transfer of records associated with the NGTL and ATCO Pipelines asset transfers.

249. The one-time capital costs of \$2.675 million are for installing signage on the pipelines acquired from NGTL and installing communications equipment at station facilities to allow communication from these sites to ATCO Pipelines' control centre. The total capital costs also include a removal cost of \$125,000.¹⁰⁹ The removal costs include labour required for the removal of existing NGTL communications equipment that is incompatible with ATCO Pipelines' SCADA system.¹¹⁰

¹⁰⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 6.1 Attachment 4, page 1 of 3.

¹⁰⁹ Exhibit 0002.00.ATCOPIPE-3577, Business cases, page 73.

¹¹⁰ Exhibit 3577-X0064, AP-AUC-2015FEB03-038(c).

250. The impact of the asset swap in the test period is a net cost of \$2.2 million to ATCO Pipelines due to higher land rights payments being transferred and due to receiving 85 metering stations. This has no net effect on the Alberta system cost of service because NGTL no longer incurs the \$1.6 million land payments or has to operate the 85 stations being transferred.¹¹¹

Commission findings

251. For the purposes of this application, the Commission reviewed the updated cost impact to ATCO Pipelines through one-time capital, one-time O&M and annual O&M costs. As stated by ATCO Pipelines, the net O&M costs to ATCO Pipelines during the test period are \$2.2 million and a one-time improvement capital expenditure of \$2.8 million. The Commission considers that the transfer of assets between ATCO Pipelines and NGTL has been approved by both the Commission and the NEB.

252. The Commission is cognizant that some one-time costs are required in order to complete the asset transfers and considers that largely, the impact of net new annual costs is negligible as they are a “transfer” of costs from NGTL to ATCO Pipelines, and vice versa, due to the transfer of assets. The Commission approves the O&M costs and the one-time capital expenses associated with integration with NGTL.

253. It should be noted that, as stated in ATCO Pipelines’ application, the difference in net book value of assets will be trued up through the NGTL integration deferral account in a future proceeding. For the purposes of this application, the Commission approves ATCO Pipelines’ placeholder amount of zero.

5 Necessary working capital

254. ATCO Pipelines submitted that a review of its lead-lag study indicated that there were no material changes that would warrant a change to the lead-lag days, which were approved in ATCO Pipelines’ 2013-2014 GRA.¹¹²

255. In this proceeding, ATCO Pipelines requested that the Commission approve the removal of deferral account balances from the calculation of necessary working capital (NWC), and instead allow ATCO Pipelines to accrue monthly carrying costs on all Commission approved deferral accounts.

256. The UCA recommended an adjustment to ATCO Pipelines’ NWC to reflect the fact that ATCO Pipelines has historically capitalized the majority of its capital additions well after mid-year, and the adjustment should be done in a way that would preserve the mid-year convention.

257. The UCA observed that consistent with past practice, ATCO Pipelines’ applied-for revenue requirement includes NWC amounts of \$27,949,000 for 2015 and \$30,012,000 for 2016. These NWC amounts include depreciation and common equity return.

¹¹¹ Exhibit 3577-X0283, AP-UCA-2015FEB03-057(b).

¹¹² Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 2.4, pages 4-5 of 7.

258. The UCA noted the following, with respect to its witness' evidence:

Mr. Bell explained that "if one wants to include depreciation and equity return in the NWC [necessary working capital] calculation to match cash flows and preserve the mid-year convention, then all material cash flows that may deviate from the mid-year convention must also be included in the NWC analysis". Mr. Bell noted that if average capital additions are later than mid-year (as his evidence demonstrated they have been, historically), then ratepayers are effectively being forced to pay for capital that is not in place, to the benefit of AP shareholders.¹¹³ [footnotes omitted]

259. During cross-examination by Commission council, Mr. Bell also stated:

My recommendation is to include an adjustment to working capital to account for the lag days in capital additions that allows the Commission to preserve the midyear convention in this proceeding. The Commission may then deliberate on whether there's something in this that says we want to look at the mid-year convention as an industry-wide conversion. Or if they wanted to do something in this decision, it's at their discretion, but my recommendation is to preserve the mid-year convention.¹¹⁴

260. The UCA explained that under the mid-year convention, capital additions are assumed to occur regularly through the year. That presumption underpins calculations like mid-year net plant, calculated by averaging opening and closing net plant balances. Mid-year net plant is in turn used to calculate the utility's return. The UCA added, "Material cash flows that may not reflect the presumption that they occur evenly throughout the year are tracked in the lead-lag study and included in the net working capital calculation, to avoid overcompensating the utility due to a mismatch of cash flows."¹¹⁵

261. In response to AP-UCA-2015MAY21-092(b),¹¹⁶ in which ATCO Pipelines provided its capital additions by month, Mr. Bell explained that when looking at the actual capital expenditures in that response, it appeared that there was a definite pattern of capital additions that occurred later in the year. On average, Mr. Bell provided that ATCO Pipelines does not capitalize 50 per cent of its annual capital additions until part way through October. If the mid-year convention was an accurate assumption, one would expect that, on average, ATCO Pipelines would capitalize about 50 per cent of its capital expenditures at approximately mid-year. Mr. Bell asserted that the analysis clearly demonstrated that, on average, the mid-year assumption was not valid.¹¹⁷

262. The UCA noted that all other major cash flows are already present in ATCO Pipelines' NWC calculations in Tables 2.4-1 and 2.4-2 of its application.¹¹⁸ Table 2.4-2 included the following list of items that are identical in principle to the cash flow associated with capital additions. The following list includes all major cash flows except capital. The only major missing item from this list is the timing of capital additions. Once the timing of capital additions is included, all major cash flows will be included in ATCO Pipelines' NWC calculation.¹¹⁹

¹¹³ Exhibit 3577-X0333, UCA argument, paragraph 88.

¹¹⁴ Transcript, Volume 4, page 759, line 19 to page 760, line 3.

¹¹⁵ Exhibit 3577-X0346, UCA reply argument, paragraph 41.

¹¹⁶ Exhibit 3577-X0212 and Exhibit 3577-0213.

¹¹⁷ Exhibit 3577-X0224, R. Bell evidence for UCA, Q11/A11, pages 9-10.

¹¹⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 2.4, pages 2-3 of 7.

¹¹⁹ Exhibit 3577-X0346, UCA reply argument, paragraphs 44-45.

- **Cash expenses:**
 - Operating and Maintenance;
 - Income Tax Installments; and
 - Franchise & Property Tax;
- **Financial items:**
 - Debt Interest;
 - Preferred Dividends;
 - Common Returns – Dividends;
 - Common Return - R.E.; and
 - Depreciation Expense;
- **Adjustments:**
 - Materials and Supplies;
 - Unamortized Debt and Preferred Discount;
 - Line Pack;
 - Salt Cavern Peaking Working Gas;
 - Future Income Tax;
 - Future Income Tax Regulatory Asset; and
 - Other.

263. The UCA submitted that, in accordance with Mr. Bell's recommendations and in order to preserve the mid-year convention in relation to capital additions, the Commission should make an adjustment to ATCO Pipelines' applied-for NWC, reducing it by \$2,800,000 in 2015 and \$2,900,000 in 2016.¹²⁰

264. ATCO Pipelines argued that while the UCA appeared to suggest that it is supportive of maintaining the mid-year convention during the test period for capital additions, its requested cost disallowance based on a working capital adjustment effectively overrides the mid-year convention for capital additions.

265. ATCO Pipelines submitted that NWC did not capture all timing differences and should not be changed in isolation for only rate base additions without reviewing other elements of the mid-year convention. ATCO Pipelines considered it inappropriate to change the convention for ATCO Pipelines alone, and any change is best introduced in a common proceeding.¹²¹

266. ATCO Pipelines observed that the Commission had confirmed the appropriateness of the mid-year convention for capital additions and capital expenditures for EPCOR Distribution & Transmission Inc. in Decision 3539-D01-2015.¹²²

267. ATCO Pipelines, therefore, submitted that the mid-year convention remains appropriate for the ATCO Pipelines system.

Commission findings

268. The Commission is satisfied that the UCA's proposal is not to deviate from the mid-year convention as confirmed by Mr. Bell. Mr. Bell's concern relates to the timing of capital additions late in the year. What Mr. Bell has proposed is essentially to adjust the NWCs lead-lag study to

¹²⁰ Exhibit 3577-X0333, UCA argument, paragraph 95.

¹²¹ Exhibit 3577-X0265, ATCO Pipelines rebuttal evidence, paragraphs 26-32.

¹²² Decision 3539-D01-2015, paragraph 774.

account for lag days in capital additions, as evidenced by the following table provided in response to UCA-AP-2015SEP03-001.¹²³

Table 13. UCA proposal to include capital additions in NWC lead-lag study

(\$000)	2015	2016	Reference
Lag days	101.42		
Calendar days	365		
Ratio	0.2779		
Capital additions	302,097	320,335	Exhibit 3577-X0212
	83,942	89,009	
Return	6.63%	6.63%	Exhibit 3577-X0010.02-Sch 3.1-1
Mid-year NWC impact	2,783	2,951	

269. In respect of the above table, Mr. Bell provided the following:

If average capital additions are later than mid-year, then customers are paying for capital that is not in place. The utility is therefore over-compensated, and there should be a reduction for the first year additions in response. Assuming a linear capitalization of additions in October, this results in 9.42 days into October that AP capitalizes its assets, resulting in 101.42 lag days between mid-year and actual capital additions. This difference must be included in the NWC calculation to avoid over-compensation of approximately \$2.8 million in 2015 and \$2.9 million in 2016.¹²⁴

270. ATCO Pipelines pointed out that in a previous decision the Commission had not accepted a similar argument by the UCA in respect of EPCOR Distribution & Transmission Inc. However, in that proceeding it was not as evident as it is in this case that for ATCO Pipelines the capital additions, on average, routinely fall after the mid-year.

271. Although actual capital additions lag the mid-year, the Commission is not persuaded to revise the calculation of NWC given the recent finding by the Commission in Decision 3539-D01-2015:

The Commission agrees with EDTI that the additional tracking proposed by the UCA would add unnecessary complexity. Consistent with Decision 2012-237, the Commission finds that it is a long-standing convention of the Commission and its predecessors to use the mid-year convention for capital additions and capital expenditures. The mid-year convention is a reasonable method to account for capital-related costs over the entire year, while recognizing that some assets are added to rate base prior to mid-year and some assets are added to rate base after mid-year. The Commission agrees with EDTI that the mid-year convention does not mean that all capital additions in every year are exactly evenly spread. Therefore, the Commission does not find that directing EDTI to provide capital additions and expenditures by month is necessary to adequately test the impact of capital additions and expenditures related to working capital and included in the forecast revenue requirement in a given year.¹²⁵

¹²³ Exhibit 3577-X0248, UCA-AP-2015SEP03-001.

¹²⁴ Exhibit 3577-X0224, R. Bell evidence for UCA, Q13/A13, pages 9-10.

¹²⁵ Decision 3539-D01-2015, paragraph 774.

272. The Commission considers that the use of the mid-year convention is an accepted practice for treating capital additions and considers any inclusion of capital additions in NWC would require a more comprehensive review of the applicability of the mid-year convention for capital related items. Therefore, ATCO Pipelines is directed to further explain, in its next GRA, why its capital additions lag the mid-year convention and whether on a go-forward basis it is, or is not, appropriate to include capital additions or other capital related items in NWC. Subject to any other findings included in this decision, the NWC forecasts for the test years are approved, as filed.

6 Operating costs

273. ATCO Pipelines' revenue requirement includes operating costs, which are composed of O&M costs and administration and general (A&G) costs. ATCO Pipelines forecasts total operating costs of \$64,682,000 in 2015 and \$70,086,000 in 2016. In the 2015 and 2016 test years, the total operating expenses represent approximately 31 and 28 per cent, respectively, of ATCO Pipelines' forecast revenue requirement.

Table 14. Total operating expenses

	2010 actual	2011 actual	2012 actual	2013 actual	2014 actual	2015 test period	2016 test period
	(\$ million)						
Operations and maintenance	40.6	45.2	29.3	30.9	28.0	34.4	38.5
Administration and general	25.0	24.0	26.5	29.9	26.9	32.3	33.5
Operating costs – Corporate (subtotal)	65.6	69.2	55.8	60.8	54.9	66.7	72.0
Less disallowed operating costs	1.5	1.1	1.3	4.7	3.5	2.0	2.0
Total operating costs – utility	64.1	68.1	54.5	56.1	51.3	64.7	70.1

Source: Exhibit 3577-X0182, Schedule 4.2.1-1 and Exhibit 3577-X0039, AP-CAL-2015FEB03-053(b) Attachment.

6.1 Direct operation and maintenance expenses

274. O&M costs include the labour and supplies costs related to the operation and maintenance of ATCO Pipelines' transmission lines, compressors, measuring and regulating stations and facilities and control and communication systems.¹²⁶

275. ATCO Pipelines' O&M costs have been adjusted for costs previously disallowed by the Commission. These costs include signature rights, medium-term and long-term incentive program costs (MTIP/LTIP), donations and sponsorships, corporate costs and the pension cost of living allowance (COLA) adjustment costs in excess of the Commission's allowed COLA increases.¹²⁷

¹²⁶ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2, page 1 of 4.

¹²⁷ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.11, page 1 of 2. Disallowed operating costs are separate from non-utility costs which are removed from the total revenue requirement and include return on rate base and income tax amounts attributable to costs incurred for non-utility functions.

276. The following table presents the forecast total O&M expenses for the period 2015 and 2016 and the years preceding the test period. From 2010-2012, ATCO Pipelines' revenue requirement was determined in a negotiated settlement process.

Table 15. O&M expenses

	2010 actual	2011 actual	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast
	(\$ million)						
Actual or forecast ¹²⁸	40.4	45.2	29.3	29.2	27.8	33.8	38.0
\$ Increase		4.8	(15.9)	(0.1)	(1.4)	6.0	4.2
% Increase		11.9	(35.2)	(0.3)	(4.8)	21.6	12.4

Source: Exhibit 3577-X0182, Schedule 4.2.1-1 and Exhibit 3577-X0064, AP-AUC-2015FEB03-077(b) Attachment.

277. The table demonstrates that actual O&M costs have decreased by 31 per cent between 2010 and 2014 but that O&M costs are forecast to increase by 22 and 12 per cent in 2015 and 2016, respectively.

278. ATCO Pipelines indicated in response to an IR that, while actuals have been provided, it is unable to break out components of the forecast revenue requirement between 2010 and 2012 because it was operating under a negotiated settlement.¹²⁹

279. In response to an IR regarding the impact of declining oil prices and the decline in the level of economic activity in Alberta, ATCO Pipelines stated that the key drivers of O&M costs are the provision of safe and reliable service, the increasing complexity of ATCO Pipelines' pipeline system and operating environment and ATCO Pipelines' labour force demographics. The price of oil and the current economic climate will have little impact on the execution of ATCO Pipelines' programs and, as such, will have little impact on O&M costs.¹³⁰

¹²⁸ These amounts are net of disallowed operating costs.

¹²⁹ Exhibit 3577-X0064, AP-AUC-2015FEB03-077(b) Attachment.

¹³⁰ Exhibit 3577-X0060, AP-AUC-2015FEB03-002.

280. ATCO Pipelines grouped its O&M expenses into the cost categories shown in the table below:

Table 16. Transmission operating expenses increase summary

	(\$ million)	2014 actual (\$)	2014 increase (\$)	2014 increase (%)	2015 costs (\$)	2015 increase (\$)	2015 increase (%)	2016 costs (\$)	2016 increase (\$)	2016 increase (%)
1	Fringe benefit transmissions labour	3.46	(1.57)	(31.3)	3.72	0.26	7.5	3.85	0.13	3.5
2	Salt cavern operation	0.75	(0.04)	(5.1)	1.00	0.25	33.3	1.03	0.03	3.0
3	Underground storage - compressors	0.08	0.08	0.0	0.27	0.19	237.5	0.27	0.00	0.0
4	Transmission operations	7.90	(0.75)	(8.7)	9.77	1.87	23.7	10.25	0.48	4.9
5	Pipeline operations	9.45	0.05	0.5	12.19	2.74	29.0	14.75	2.56	21.0
6	Compressor operations	1.67	(0.13)	(7.2)	1.97	0.30	18.0	2.11	0.14	7.1
7	Measurement and regulating	5.04	(0.06)	(1.2)	5.67	0.63	12.5	6.50	0.83	14.6
8	Transmission other	0.99	(0.07)	(6.6)	1.07	0.08	8.1	1.10	0.03	2.8
9	Cost of providing service	1.85	0.11	6.3	1.92	0.07	3.8	1.98	0.06	3.1
10	Recovery of costs	(2.82)	(0.19)	(7.2)	(3.21)	-0.39	13.8	(3.30)	-0.09	2.8
11	Less disallowed operating costs	(0.55)	1.16	68.2	(0.55)	0.00	0.0	(0.55)	0.00	0.0
	Total	27.8	(1.41)	(4.8)	33.8	6.00	21.6	38.0	4.20	12.4

Source: Exhibit 3577-X0182, Schedule 4.2.1-2 and Exhibit 3577-X0064, AP-AUC-2015FEB03-077(c) Attachment.

281. ATCO Pipelines explained the differences in forecast costs for the major O&M categories, for the test period, as follows.

282. Transmission function costs have been split between internal labour costs and external supply costs. ATCO Pipelines forecast transmission labour expenses of \$16.781 million and \$18.095 million in 2015 and 2016, respectively, as compared against 2014 actuals of \$13.856 million.¹³¹ The forecast transmission labour expenses are higher due to annual labour inflation and growth in FTE positions.¹³² Labour cost components of O&M will be discussed further in Section 6.2 below.

283. The increases in underground storage compressors shown in Table 16 during the test period are due to area maintenance activity on the NGTL system, which has resulted in lower than normal pressures at the Inland and Norma tie-in locations and has resulted in increased operations at the Salt Cavern facility over the winter period. As a result, ATCO Pipelines has implemented a 24 x 7 shift of employees on site during the winter period. ATCO Pipelines has also implemented improvements that allow it to inject gas during non-peak times during the winter which provides greater availability but requires compressions and increases electricity costs.¹³³

284. With respect to training and mentoring costs, these costs are tracked under transmission operations. The forecast for training expenses in 2015 is \$1.0 million, which includes \$0.4

¹³¹ Exhibit 3577-X0171, AP-AUC-2015MAY21-004 Attachment 3.

¹³² Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.3, pages 3-4 of 7.

¹³³ Exhibit 3577-X0064, AP-AUC-2015FEB03-080.

million for Incident Command System (ICS) training, and the forecast for training expenses in 2016 is \$0.7 million which includes \$0.1 million for ICS training.¹³⁴

285. ATCO Pipelines forecast increases to transmission supplies for the 2015 and 2016 test years of \$17.583 million and \$20.453 million, respectively, as compared to 2014 actuals of \$14.105 million. ATCO Pipelines explained that transmission supplies include the following expenses: contract services, utilities, company vehicles, fringe benefits, travel, accommodations and meals, the NGTL asset swap and materials, equipment and tools. Transmission supply costs are forecast to increase largely due to increases in contract services, utilities, the NGTL asset swap and materials, equipment and tools.¹³⁵ These costs will be discussed further in Section 6.3 below.

286. One June 22, 2015, ATCO Pipelines provided an update to its application however, there were no updates to O&M costs.¹³⁶

287. None of the interveners submitted views on the overall forecast O&M costs.

Commission findings

288. The Commission has examined the evidence on the record of this proceeding respecting ATCO Pipelines' forecast O&M costs. In having reviewed the forecast O&M costs, the application, responses to IRs, the oral testimony, the argument and reply argument submitted by parties and other information, the Commission approves ATCO Pipelines' forecast O&M costs for the years 2015 and 2016, subject to any adjustments arising from the findings for those O&M costs components specifically identified in the sections below.

6.2 O&M labour costs

289. O&M labour costs are forecast to be higher in 2015 and 2016 primarily due to annual labour inflation and growth in FTE positions. In addition to growth in the number of FTEs, ATCO Pipelines anticipated recruiting replacements for a number of retirements over the next several years, which requires increased training and mentoring to integrate new hires into ATCO Pipelines.¹³⁷

290. O&M labour is classified by activity, namely salt cavern operations, gas control, customer and pipeline system support, engineering and planning, pipeline operations, safety and training, compressor operations and measurement and regulating operations. Increases in labour costs due to wage inflation are discussed in Section 6.2.1 below and increases in labour costs due to the addition of FTE positions is discussed in Section 6.2.5 below.

Commission findings

291. As discussed in Section 6.3.1 below, the expenses for the gap analysis for implementation of ISO 55001 were denied. ATCO Pipelines is therefore directed to remove any O&M labour expense associated with this project in the compliance filing. All other O&M labour expenses will be discussed in the sections below.

¹³⁴ Exhibit 3577-X0064, AP-AUC-2015FEB03-081(c).

¹³⁵ Exhibit 3577-X0161, AP-AUC-2015MAY21-004 Attachment 3.

¹³⁶ Exhibit 3577-X0179, ATCO Pipelines update application.

¹³⁷ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.1, pages 3-4 of 13.

6.2.1 Salary escalators

6.2.1.1 In-scope employees

292. ATCO Pipelines, and the Natural Gas Employee Association, who represent ATCO Pipelines' association members (in-scope employees), negotiated a two-year collective agreement for the period January 1, 2014 to December 31, 2015. The agreement provided for a wage increase of 3.5 per cent in both 2014 and 2015. ATCO Pipelines also submitted that the base increase for 2015 and the forecast for 2016 is consistent with other recent Alberta union wage settlements.¹³⁸

293. Further, ATCO Pipelines stated that the Mercer (Canada) Limited (Mercer) 2016 forecast for out-of-scope labour for the pipeline sector represented another source of information that supported general labour inflation for ATCO Pipelines' forecast in-scope labour cost.¹³⁹

294. The CCA submitted that the current Alberta labour market conditions do not support inflation increases for labour. As such, the CCA requested the Commission direct ATCO Pipelines to limit labour inflation rates to zero per cent for labour contracts which were not settled by the time of the hearing.¹⁴⁰

295. CAPP noted that ATCO Pipelines' wage settlement for its in-scope employees for 2016 was incomplete. Lacking a settlement for 2016, CAPP recommended that ATCO Pipelines' in-scope wages for 2016 should be in a deferral account because the outcome of the negotiations and the inflation factor was uncertain at the time of the hearing.¹⁴¹

296. The UCA submitted that it did not contest ATCO Pipelines' in-scope labour projection of 3.5 per cent for 2015 on the basis that the 3.5 per cent was a function of the labour agreement that had already been negotiated and did not expire until the end of 2015.¹⁴² The UCA took issue with the in-scope labour projection provided by ATCO Pipelines for 2016. The UCA submitted that the figures contained in ATCO Pipelines' application are based on data collected in an era of economic growth, rather than the current climate of lower growth. This data and the assumptions derived from it are stale and are no longer of assistance to the Commission in assessing ATCO Pipelines' application.¹⁴³

297. The labour agreement by which ATCO Pipelines will determine its in-scope labour costs for 2016 has yet to be concluded. The UCA argued that ATCO Pipelines will be negotiating with its employee association, in the current economic climate, which can be fairly characterized as an employer's market. As detailed above, the Commission has heard evidence of mounting layoffs and declining or contracting economic growth. In this climate, the UCA asserted that ATCO Pipelines should be able to negotiate a much better labour agreement than it did under very different circumstances in 2013, when it was forced to pay a 3.5 per cent increase.¹⁴⁴

298. The UCA submitted that ATCO Pipelines had testified that, due to "exceptional circumstances," it did not pay any of its employees any variable pay in 2014. ATCO Pipelines

¹³⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.4, page 1 of 4.

¹³⁹ Exhibit 3577-X0328, ATCO Pipelines argument, paragraph 140.

¹⁴⁰ Exhibit 3577-X0331, CCA argument, paragraph 92.

¹⁴¹ Exhibit 3577-X0326, CAPP argument, page 12.

¹⁴² Exhibit 3577-X0333, UCA argument, paragraph 31.

¹⁴³ Exhibit 3577-X0333, UCA argument, paragraphs 32-33.

¹⁴⁴ Exhibit 3577-X0333, UCA argument, paragraphs 34-35.

testified that it made the decision not to fund the variable pay program (VPP), in large part, because the marketplace did not require it to distribute VPP in order to retain and attract talent. This evidence is consistent with ATCO Pipelines' testimony that it had observed a material rise in the number of applicants for its job postings. This evidence of an employer's market and of rising demand for positions with ATCO Pipelines undermines its argument that its compensation lags behind its competitors and that it must increase its compensation to "catch up with the market."¹⁴⁵

299. The UCA submitted that it is disingenuous for ATCO Pipelines to cut labour costs for the account of its shareholders, specifically VPP, by claiming there is no shortage of talent at ATCO Pipelines, while at the same asking the Commission to approve labour cost increases paid by ratepayers (in-scope labour) to retain and attract talent.¹⁴⁶ Further, publicly approving an application containing above-market labour assumptions is likely to undermine ATCO Pipelines' bargaining position with its employee association.¹⁴⁷

300. Finally, the UCA submitted that ATCO Pipelines has provided evidence showing a significant reduction of its 2016 out-of-scope labour estimates, from 4.2 per cent to 3.0 per cent, without a similar, or any, reduction in its 2016 in-scope labour assumptions. The UCA submitted that both sets of assumptions are affected by the same market forces and that ATCO Pipelines cannot credibly say that one has decreased so significantly while denying any decrease in the other.¹⁴⁸

301. Accordingly, the UCA stated that it would be inappropriate and imprudent for the Commission to approve an application assuming a forecast figure that is out of step with the current economic climate, particularly in the absence of persuasive or credible evidence as to why ATCO Pipelines' assumptions remain valid.¹⁴⁹

302. The UCA recommended that, given ATCO Pipelines' admission that there is some cross-over between laid-off energy worker skills and those required by ATCO Pipelines, and its conduct in not paying VPP, a zero per cent increase for 2016 is a reasonable expectation of the labour negotiation outcome. In the alternative, the most recent average weekly earnings data on the record would also be a reasonable estimate of what can be expected from the negotiations, which would be more appropriate than other proxy metrics like Alberta CPI on the basis that it is a forecast informed by the employment market, rather than an inflation measure relating to a broad basket of consumer goods.¹⁵⁰

303. ATCO Pipelines replied that CAPP's request for a deferral account for in-scope wages is not consistent with the traditional deferral account criteria for this category of costs. Additionally, these costs are not material and are within the ability of ATCO Pipelines to forecast at a reasonable level, for example, a one per cent change in the in-scope inflation rate amounts to only \$92,000.¹⁵¹

¹⁴⁵ Exhibit 3577-X0333, UCA argument, paragraphs 36-37.

¹⁴⁶ Exhibit 3577-X0333, UCA argument, paragraph 38.

¹⁴⁷ Exhibit 3577-X0333, UCA argument, paragraph 39.

¹⁴⁸ Exhibit 3577-X0333, UCA argument, paragraph 40.

¹⁴⁹ Exhibit 3577-X0333, UCA argument, paragraph 41.

¹⁵⁰ Exhibit 3577-X0333, UCA argument, paragraph 42.

¹⁵¹ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 36.

304. ATCO Pipelines submitted that the UCA's zero per cent increase for 2016 is contrary to the evidence, and the Mercer study shows an increase of three per cent for out-of-scope employees, which also has relevance to in-scope employees. Further, general inflation indicators are all generally positive for the test years, not flat.¹⁵² ATCO Pipelines stated that interveners, in particular the UCA, had spent some time in cross-examination suggesting that the general economic downturn precipitated by the decline in oil prices over the last year must be directly relevant to ATCO Pipelines' forecast costs. ATCO Pipelines testified¹⁵³ that its costs are largely driven by sectors of the economy, in particular gas transmission construction and ILI work, that remain very busy notwithstanding the general economic climate.

305. ATCO Pipelines also submitted that the average weekly earnings data does not provide a reasonable estimate of its in-scope labour costs because average weekly earnings are not specific to ATCO Pipelines' industry sector, whereas the Mercer evidence is industry specific.¹⁵⁴

306. Additionally, the UCA is completely off the mark with its allegations of "disingenuous" conduct on the part of ATCO Pipelines. Most significantly, any savings in labour costs resulting from lower VPP payouts are not for the account for ATCO Pipelines' shareholders, but for the account of ratepayers. In testimony, ATCO Pipelines confirmed it will refund the 2014 VPP non-payment to customers. ATCO Pipelines' decision not to make any 2014 VPP payments resulted in a direct savings for customers, with no benefit to its shareholders. Further, when ATCO Pipelines made the decision not to fund the VPP in 2014, it did so not because "... there was no shortage of talent at ATCO Pipelines ..." but because extraordinary market conditions did not require VPP payouts in order to retain and attract personnel in 2014.¹⁵⁵

Commission findings

307. The two-year collective agreement between ATCO Pipelines and the Natural Gas Employee Association for in-scope employees is effective between January 1, 2014 and December 31, 2015. The agreement provided for an increase of 3.5 per cent in 2015. No party opposed the 3.5 per cent increase for 2015. The Commission finds ATCO Pipelines' 2015 in-scope salary escalation rate of 3.5 per cent for 2015 to be reasonable and it is approved on a final basis.

308. With respect to the 2016 in-scope escalation factor, the Commission does not find that a deferral account is necessary. The Commission agrees with ATCO Pipelines that this cost does not currently meet the criteria for deferral account treatment and the Commission acknowledges that the salary escalator for 2016 to be negotiated between ATCO Pipelines and the Natural Gas Employee Association may be higher or lower than the forecast to be approved in this decision.

309. The Commission has approved a salary escalation rate of 3.0 per cent for out-of-scope employees for 2016 in Section 6.2.1.2 below, and the Commission similarly approves 3.0 per cent for in-scope salary escalation for 2016, on a final basis. The 3.0 per cent approved is consistent with the salary escalator approved for out-of-scope employees and aligns with the October 1, 2015, Mercer forecast provided on the record of this proceeding. The Commission considers that the 3.0 per cent for in-scope employees reflects the current labour market conditions and will, therefore, reflect any escalation in ATCO Pipelines labour costs.

¹⁵² Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 165.

¹⁵³ Transcript, Volume 2, page 347, line 18 to page 348, line 23.

¹⁵⁴ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 109.

¹⁵⁵ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 168.

6.2.1.2 Out-of-scope employees

310. ATCO Pipelines retained Mercer to provide advice with respect to the level of salary escalation applicable to non-union (out-of-scope) employees for 2015 and 2016. For 2015 and 2016, Mercer recommended a range of escalation for out-of-scope employees of 4.1 per cent to 4.3 per cent, and this range included the salary increase budget data and promotional increases. ATCO Pipelines used a 4.2 per cent labour cost increase for its out-of-scope employees for 2015 and 2016.¹⁵⁶

311. ATCO Pipelines submitted that it targets the 50th percentile of the market for its base employee compensation as well as its total employee compensation. ATCO Pipelines submitted that the target is reasonable as it allows ATCO Pipelines to manage its costs while also positioning it to provide competitive compensation and compete effectively with other companies for talent.¹⁵⁷

312. During the oral hearing, an update from Mercer was filed dated October 1, 2015 showing new survey data for 2015 and 2016. In the update from Mercer, the median salary increase budget reported for 2015 actual was 3.0 per cent and for 2016 projected was 3.0 per cent.¹⁵⁸

313. During the oral hearing, Mr. Shkrobot, witness for ATCO Pipelines, discussed that although the updated Mercer survey data reflected that the market had decreased to 3.0 per cent, ATCO Pipelines' requested 4.2 per cent increase remains reasonable because it is attempting to close the gap between its overall out-of-scope compensation levels and market levels:

Q. MR. STAINER: And I understand that one of the explanations that's been put forward for this is that AP is taking the opportunity to catch up with the market as far as its compensation?

A. MR. SHKROBOT: So, yes, we recognize that overall the survey data may suggest that 3 percent -- 3 percent is the new forecast for out-of-scope inflation for our pipeline mid sector. But we also recognize that we significantly lag the market, and that's why we remain committed that 4.2 percent reflects [the best] forecast at the time, given that we need to catch up in the marketplace.

Q. MR. STAINER: So you've just said that 3 percent is the new forecast for the market for people who don't need to catch up?

A. MR. SHKROBOT: So 3 percent would be the average increase in the market. And in the Mercer's compensation review, we show that we lag 15 percent in total compensation.

Q. MR. STAINER: And you're lagging compensation, and you're attempting to make up for that; correct?

A. MR. SHKROBOT: Yes. So we are endeavouring to, again, target the 50 percentile, which would be the mean. And, yes. So our target and our goal is to on a -- I guess, on a practical basis, gain ground back to the median.¹⁵⁹

¹⁵⁶ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.4, page 2 of 4 and Attachment 1.4.

¹⁵⁷ Exhibit 3577-X0060, AP-AUC-2015FEB03-013(c)-(d).

¹⁵⁸ Exhibit 3577-X0304, undertaking, Mercer October 1, 2015 memo.

¹⁵⁹ Transcript, Volume 2, page 446, line 2 to page 447, line 7.

314. CAPP disagreed with ATCO Pipelines' requested wage increases for out-of-scope employees and submitted that the increase was not justified and should be reduced. CAPP submitted that the Mercer report confirmed that compensation differs geographically between Edmonton and Calgary and that ATCO Pipelines' witness, Mr. Yung of Mercer, had stated that compensation for Edmonton employees was competitive.¹⁶⁰

315. CAPP submitted that with respect to ATCO Pipelines' total compensation, ATCO Pipelines made the decision not to award variable pay for 2014 in May of 2015. CAPP stated that ATCO Pipelines' management has the ability to award variable pay if it is needed to bridge any compensation shortfall, and they felt that they did not need to in 2015. CAPP recommended that the Commission should not approve ATCO Pipelines' out-of-scope inflation factors, which are based on unrepresentative averages and are above the levels needed to compensate employees at a competitive level.¹⁶¹

316. The UCA submitted that the most current information on the record of the proceeding should be used with respect to key economic assumptions. The UCA recommended a 2015 and 2016 out-of-scope labour assumption of 3.0 per cent for each year as found in the updated memo received from Mercer on October 1, 2015.¹⁶²

317. ATCO Pipelines submitted that CAPP had been mistaken about what Mr. Yung said and he was very clear that the statement about Edmonton compensation levels was a reference to generic Edmonton market compensation levels and not ATCO Pipelines' compensation levels.¹⁶³ CAPP's suggestion that its approach not to award variable pay to select employees in 2014 because of extraordinary market conditions as a reason to deny an increase in out-of-scope compensation generally, ignored the evidence that ATCO Pipelines' out-of-scope total remuneration levels continue to lag the market by 15 per cent.¹⁶⁴

318. ATCO Pipelines also submitted that the UCA's recommendation of 3.0 per cent for out-of-scope labour ignored the Mercer evidence that ATCO Pipelines lags the market in total compensation by 15 per cent. ATCO Pipelines submitted that this is an important part of its request for an increase of 4.2 per cent.¹⁶⁵

Commission findings

319. ATCO Pipelines submitted that its original forecast of 4.2 per cent for 2015 and 2016 for out-of-scope employees remains reasonable because its total compensation lags the market by 15 per cent. The Commission has compiled the following table that includes the estimates of out-of-scope escalation provided in Mercer's evidence and updates:

¹⁶⁰ Exhibit 3577-X0326, CAPP argument, page 12.

¹⁶¹ Exhibit 3577-X0326, CAPP argument, page 13.

¹⁶² Exhibit 3577-X0333, UCA argument, paragraphs 43-44.

¹⁶³ Transcript, Volume 3, page 506, lines 4-19.

¹⁶⁴ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 39.

¹⁶⁵ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 170.

Table 17. Mercer salary increase projections

	Percentage	Source
Initial recommendation	4.1% to 4.3%	Exhibit 0007.00.ATCOPIPE-3577, Section 1.4, Attachment 1.4
January 2015 update – informal poll	3.8% for 2015	Exhibit 3577-X0060, AP-AUC-2015FEB03-009(d)
March/April 2015 update – informal poll	3.0% for 2015	Exhibit 3577-X0173, AP-UCA-2015MAY21-095(a).
October 1, 2015 – memo	3.0% actual for 2015, 3.0% projected for 2016	Exhibit 3577-X0304, Undertaking, Mercer October 1, 2015 memo

320. Mercer's evidence shows that salary escalators are on a downward trend.

321. The evidence before the Commission does not support that the salary escalators for out-of-scope employees applied-for should be 4.2 per cent for 2015 and 2016 because salary escalation rates are on a downward trend, which could be partially due to changes in the Alberta economy. The Commission agrees with the UCA, that three per cent for out-of-scope labour escalation is more reflective of the current market, and the Commission finds that three per cent is based on the best available information on the record.

322. The Commission does not accept ATCO Pipelines argument that 4.2 per cent is reasonable because it lags the market in total compensation by 15 per cent. The Commission finds that when looking at base salary, ATCO Pipelines is, on average, two per cent above the 50th percentile. The Commission finds that there is no need for an increased salary escalator to compensate for the any lag with respect to ATCO Pipelines' base salary target of the 50th percentile.¹⁶⁶ The Commission does not find that it is reasonable to escalate base salaries due to ATCO Pipelines' assertion that this will balance out its total compensation that is below the market. The Commission considers that ATCO Pipelines has other means to manage its total compensation.

323. When looking at target total cash, which includes base salary and short-term incentives, ATCO Pipelines is, on average, seven per cent below the 50th percentile.¹⁶⁷ The Commission finds that it is the incentive portion of target total cash that has brought ATCO Pipelines' average down, from the above two per cent, to below seven per cent of the 50th percentile. ATCO Pipelines stated at the oral hearing that:

Q. MR. SCHULTZ: But Mercer seems to indicate that the eligibility that you have is significantly lower than your peer group. Do you understand that to be the case?

A. MR. SHKROBOT: I would say the funding level for short-term incentive programs is well below market, is what the Mercer's report indicates.

Q. MR. SCHULTZ: I see. So I guess two questions come out of that:

Will you be moving to extend variable -- the variable pay program eligibility beyond the 70 employees you forecast in light of the Mercer study? That's the first question.

¹⁶⁶ Exhibit 3577-X0308, undertaking, updated Mercer report, page 4 of 30.

¹⁶⁷ Exhibit 3577-X0308, undertaking, updated Mercer report, page 4 of 30.

A. MR. SHKROBOT: So as we said in our application, we will continue to evaluate the market. The whole purpose of the VPP and overall compensations ensure that we continue to be able to [attract] and retain our employees.

And although we have not extended it beyond the 70 positions, included in our application, what we said we needed to do is be flexible, and to the extent that we are having difficulty attracting or [retaining] employees, we will -- may be required to extend that beyond the 70 positions identified.

Q. MR. SCHULTZ: I see. And you had met -- you had also responded to me in terms of the amount of variable pay that you actually pay, which I took went to the actual percentages of entitlement to variable pay.

Is there, then, also the potential for your looking at increasing the amount that you are prepared -- that people could be eligible for?

A. MR. SHKROBOT: That's correct. To the extent that market dictates and we find in our position that we -- the only way to continue to retain and [attract] we have to go increase that percentage.¹⁶⁸

324. The Commission finds that target total compensation includes items such as variable pay, perquisites, long-term incentive pay, pension and savings and health and group benefits.¹⁶⁹ Although some of these items are not included for recovery in ATCO Pipelines' revenue requirement, the Commission considers that it is within the discretion of ATCO Pipelines' management to review if these tools are required to retain and attract employees, and therefore, ATCO Pipelines has the ability to vary any of these items to meet its objectives with respect to total compensation.

325. Accordingly, the Commission approves a 3.0 per cent out-of-scope salary escalation factor for both 2015 and 2016. The Commission considers that the 3.0 per cent should be inclusive of all salary increases and promotional increases. The Commission directs ATCO Pipelines to reflect the 3.0 per cent out-of-scope escalation factor in its compliance filing to this decision.

6.2.2 Variable pay program

326. In 2013, ATCO Pipelines implemented a new VPP, which was approved by the Commission in Decision 2013-430. The VPP was introduced as a means to attract and retain employees within the organization. ATCO Pipelines submitted that it had rolled out its VPP targeted at leadership positions and positions that are critical to operating and building the business. The VPP is based on individual employee performance as well as the performance of the employee's department and the company. Although ATCO Pipelines has not forecast an extension of the VPP in 2015-2016 to other levels of the organization, it will continue to monitor and evaluate the need to adjust the VPP as the market dictates.¹⁷⁰

327. The CCA noted that there was no variable pay paid out in 2014. The CCA requested that the Commission deny ATCO Pipelines' forecast for variable pay for 2015 and 2016. The CCA

¹⁶⁸ Transcript, Volume 1, page 61, line 18 to page 63, line 1.

¹⁶⁹ For example see Exhibit 3577-X0308, undertaking, updated Mercer report, page 4 of 30.

¹⁷⁰ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.8, page 1 of 2.

further requested that the Commission direct ATCO Pipelines to credit back previous years' unpaid variable pay, as part of the compliance filing for this decision.¹⁷¹

328. ATCO Pipelines submitted that the non-payment of the VPP in 2014 was due to extraordinary circumstances and the fact that it had acted prudently and did not authorize VPP payouts in 2014 due to extraordinary market conditions should not now be held against it. ATCO Pipelines testified that:

Q. MR. WACHOWICH: ...Why was VPP not funded in 2014?

A. MR. SHKROBOT: The payment or non-payment of VPP in 2014 reflected the -- I guess what we would call exceptional circumstances in the marketplace...in terms of the economy and compensation from other employers.

Q. MR. WACHOWICH: And what were those exceptional circumstances? I'm trying to --

A. MR. SHKROBOT: So exceptional circumstances where there had been some layoffs and companies were not funding their bonus programs. So when we looked at -- as management we looked at the overall marketplace, again, the VPP as a tool -- one of the tools to attract and maintain employees. A decision was made to not fund and not pay out the VPP based on these -- what we consider extreme circumstances, and it put that amount to be refunded back to customers...¹⁷²

329. ATCO Pipelines submitted that it must retain the ability to react to the marketplace, as required, to attract and retain employees. A further consideration is that ATCO Pipelines' out-of-scope employees lagged in the marketplace in overall compensation by some 15 per cent.¹⁷³ Additionally, ATCO Pipelines confirmed that the unpaid 2013 and 2014 VPP amounts would be refunded back to customers through its variable pay deferral account.¹⁷⁴

Commission findings

330. ATCO Pipelines forecast \$2.628 million in 2015 and \$2.766 million for its variable pay program in the test years.¹⁷⁵ The Commission notes that, as ATCO Pipelines has acknowledged, it has a variable pay deferral account and any VPP amounts not paid out during the test period will be refunded to customers. ATCO Pipelines confirmed at the hearing that unpaid amounts from 2013 and 2014 have been refunded back to customers:

A. MR. SCHKROBOT: ...A decision was made to not fund and not pay out the VPP based on these -- what we consider extreme circumstances, and it put that amount to be refunded back to customers --

Q. MR. WACHOWICH: Okay. When you say "refunded back to customers," it goes back into the -- I'm going to call it general revenue of the company and since it's --

¹⁷¹ Exhibit 3577-X0331, CCA argument, paragraphs 86-88.

¹⁷² Transcript, Volume 1, page 74, line 23 to page 75, line 15.

¹⁷³ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 103.

¹⁷⁴ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 104.

¹⁷⁵ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines, application, Section 4.2.8, Table 4.2.8-1.

A. MR. SHKROBOT: No. It's subject to deferrals. So we actually refund that, as included in Section 5 of our application. So we refund that back to customers.¹⁷⁶

331. In Decision 2013-430, the Commission directed ATCO Pipelines to establish a variable pay deferral account to protect customers from amounts of the VPP costs that were not paid out during the test period. ATCO Pipelines has confirmed in testimony that amounts unpaid from 2013 and 2014 were refunded back to customers.

332. Upon review of the record, the Commission considers that the forecast VPP amounts are reasonable and gives ATCO Pipelines the ability to react to the marketplace and manage its employee retention. The Commission denies the CCA's request and approves ATCO Pipelines' forecast variable pay for 2015 and 2016, as filed.

6.2.3 Variable pay deferral account

333. ATCO Pipelines was directed to establish a variable pay deferral account to capture the differences between the actual and approved VPP payouts in the 2013 and 2014 test years. ATCO Pipelines submitted that it had now designed and formalized its VPP, and therefore requested that the Commission amend the deferral account definition to capture all variances where actual VPP costs are higher or lower than approved by the Commission, in order to provide balance to ATCO Pipelines and its customers.¹⁷⁷

334. ATCO Pipelines also submitted that the company needed to respond to market conditions for employee compensation that are outside its control. To the extent that market conditions dictate, ATCO Pipelines submitted that it needed to maintain a flexible approach to the VPP.¹⁷⁸

335. The CCA disagreed with ATCO Pipelines' request that the variable pay deferral account be symmetrical and stated that ATCO Pipelines statement that its proposal is "providing equal protection to AP and its customers" is incorrect. The CCA submitted that ATCO Pipelines controls all the information and the evaluation upon which the variable pay is paid out and therefore the risk is asymmetrical. Customers have no say in what amounts are paid out. The CCA submitted that ATCO Pipelines was proposing to transfer increased risk to customers without an assessment of that risk.¹⁷⁹

336. The CCA submitted that the party who is most able to manage the risk should bear the risk and that deferral accounts do not have to be symmetrical. The CCA also submitted that given the current market conditions and likely conditions for at least the early part of 2016, the market conditions do not necessitate the use of variable pay. The CCA recommended that the request to have customers bear the risk of higher than forecast VPP costs should be denied.

337. CAPP submitted that ATCO Pipelines' request to capture variances where actual VPP costs are higher or lower than forecast is unreasonable and contrary to previous Commission rulings. CAPP disagreed that a deferral account needed to be symmetrical and submitted that ATCO Pipelines request to adjust its deferral account upwards removes its accountability to its

¹⁷⁶ Transcript, Volume 1, page 75, lines 12-21.

¹⁷⁷ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.8, page 1 of 2.

¹⁷⁸ Exhibit 3577-X0033, AP-CCA-2015FEB03-033.

¹⁷⁹ Exhibit 3577-X0331, CCA argument, paragraphs 81-82.

forecast.¹⁸⁰ CAPP identified three components within ATCO Pipelines' management control that expose customers to increased risk:

- The number of ATCO Pipelines employees eligible for the VPP.
- General criteria on which ATCO Pipelines bases its VPP payments.
- The VPP amount can range from one to 1.5 times the target award.¹⁸¹

338. ATCO Pipelines submitted that its request for symmetrical treatment of the VPP deferral account is fair and warranted. ATCO Pipelines stated that it had not extended the VPP program and it still remains well below the mark on short-term incentive compensation. The proposal is a compensation plan that is below market, while at the same time, flexible to respond to changing market conditions.¹⁸²

339. ATCO Pipelines argued that while it may administer the VPP, it had no control over the marketplace, which is the driver for the VPP payouts.¹⁸³ ATCO Pipelines submitted that symmetrical treatment of the VPP deferral account is fair and that it had demonstrated that it is a good steward of customers' money when it comes to the VPP, given the non-expansion to all employees in 2013 and 2014, despite the expansion being approved and included in rates.¹⁸⁴

Commission findings

340. In Decision 2013-430, the Commission directed ATCO Pipelines to establish a variable pay deferral account and stated, as follows:

321. The VPP is controlled by the utility and employee eligibility and any payments made on VPP objectives are solely at the discretion of ATCO Pipelines. If the utility has the discretion to increase the VPP costs and participants, customers would be exposed to a significant risk of additional costs. The Commission considers that an asymmetrical deferral account protects customers from variances between forecast and actual costs of the VPP which is solely under management control....¹⁸⁵

341. The Commission reaffirms its finding from Decision 2013-430 and finds that there has been no material change to ATCO Pipelines' VPP since it last made its decision on this issue. The Commission continues to find that there is not enough historical data with respect to variable pay to ensure that the VPP will be at levels that are consistent with forecast VPP costs. The VPP is controlled by the utility, and is managed by ATCO Pipelines, and any payments made are at the sole discretion of ATCO Pipelines, such as the zero amount "paid out" in 2014.

342. Therefore, the Commission finds that there is insufficient information to allow for the symmetrical treatment of the VPP deferral account and that the asymmetrical variable pay deferral account continues to be reasonable for ATCO Pipelines' VPP costs. Accordingly, no change to the VPP deferral account is required.

¹⁸⁰ Exhibit 3577-X0326, CAPP argument, pages 14-15.

¹⁸¹ Exhibit 3577-X0326, CAPP argument, pages 15-16.

¹⁸² Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 48.

¹⁸³ Exhibit 3577-X0033, AP-CCA-2015FEB03-033.

¹⁸⁴ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 49.

¹⁸⁵ Decision 2013-430, paragraph 321.

6.2.4 Pension costs

343. The oral hearing for ATCO Utilities' 2013 Pension application¹⁸⁶ was conducted in September 2014. The outcome of that proceeding will establish the approved defined benefit pension costs to be used in the determination of ATCO Pipelines' final deferral account balance for 2013.

344. The differences between the actual defined benefit pension costs incurred and the placeholder values included in ATCO Pipelines' approved 2013-2014 revenue requirement have been included in its defined benefit deferral account which will be settled upon the completion of the 2013 and 2014 pension applications.¹⁸⁷ The Commission's findings on the defined benefit deferral account are discussed in Section 8 below.

345. On December 6, 2013, ATCO Electric Ltd., ATCO Gas, and ATCO Pipelines (the ATCO Utilities) filed an application requesting approval of its the 2013 pension application. In that application, the ATCO Utilities filed an updated Mercer actuarial valuation for pension funding as of December 31, 2012 (2012 valuation report). According to the 2012 valuation report, the pension plan had a deficiency funding requirement. The ATCO Utilities requested a cost recovery using a COLA based on 100 per cent of the CPI to a cap of three per cent as calculated in the 2012 valuation report, to be effective January 1, 2013. The ATCO Utilities requested that the 2013 pension costs of \$7.1 million for ATCO Electric – Transmission and \$5.4 million for ATCO Pipelines be approved, as established by the 2012 valuation report. Based on the Commission's direction in Decision 2011-391,¹⁸⁸ which limited the COLA adjustment to 50 per cent of the consumer price index (CPI) to a cap of three per cent (50 per cent COLA) for ATCO Electric – Transmission and ATCO Pipelines, a total revenue requirement reduction of \$4.9 million was necessary.

346. In Decision 2954-D01-2015,¹⁸⁹ regarding the 2013 pension application, the Commission found that there had not been a material change in circumstances or changes to the provisions of the pension plan that persuaded the Commission to find that an increase in the COLA to 100 per cent of CPI to a cap of three per cent was reasonable. Decision 2954-D01-2015 reaffirmed that a COLA at 50 per cent of CPI up to three per cent was reasonable in setting just and reasonable rates, considering both the interests of the ATCO Utilities and of customers.

347. The current 2014 Pension application¹⁹⁰ includes the most recent actuarial evaluation of the ATCO Utilities defined benefit pension plan, as at December 31, 2013, which addresses the funding requirements for the defined benefit plan for 2014 through 2016. The application includes forecast defined benefit plan costs as recommended by this evaluation.¹⁹¹ ATCO Pipelines applied for defined benefit pension costs of \$2.559 million for 2015 and \$2.559 million

¹⁸⁶ Proceeding 2954, Application 1610148-1.

¹⁸⁷ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 1.3, page 5 of 7.

¹⁸⁸ Decision 2011-391: ATCO Utilities (ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd.), 2011 Pension Common Matters, Proceeding 999, Application 1606850-1, September 27, 2011.

¹⁸⁹ Decision 2954-D01-2015: ATCO Utilities (ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd.), 2013 Pension Application, Proceeding 2954, January 15, 2015. Decision 2954-D01-2015 (Errata) issued May 28, 2015.

¹⁹⁰ Proceeding 3405, Application 1610833-1, filed September 10, 2014.

¹⁹¹ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 1.3, pages 4-5 of 7.

for 2016 as placeholders,¹⁹² and each year included a reduction of \$0.818 million to reflect the 50 per cent COLA reduction, as reaffirmed in 2954-D01-2015.¹⁹³

348. In argument, the CCA and CAPP submitted that given that the Supreme Court of Canada had ruled on the issue of the ATCO Utilities appeal, ATCO Pipelines' request for a placeholder for these costs should be denied.¹⁹⁴

349. ATCO Pipelines explained in testimony that a placeholder is still required pending the outcome of the current 2014 pension application that addresses pension funding between the 2014 to 2016 years.¹⁹⁵

Commission findings

350. The Commission notes that the 2014 pension application is still ongoing and will impact ATCO Pipelines' 2015 and 2016 revenue requirement because the 2014 pension application addresses the funding requirements for the defined benefit plan for 2014 through 2016. Therefore, the Commission approves ATCO Pipelines' request for its defined benefit pension costs to be treated as placeholder amounts for costs related to the 2014 pension application.

6.2.5 FTE forecasts

351. ATCO Pipelines defines a FTE as:

- One employee working full-time for the entire year.
- Two people working half-time for the full year.
- Two people working full-time for half a year.
- Various other combinations of part-time or partial year employment.¹⁹⁶

352. On an overall basis, ATCO Pipelines has forecast 36 additional FTEs in 2015 and 10 in 2016. This results in total forecast FTEs of 470 at year-end of 2015 and 480 at year-end of 2016. ATCO Pipelines confirmed that the new positions will be full-time permanent positions.¹⁹⁷

¹⁹² Exhibit 3577-X0179, ATCO Pipelines updated application, Section 1.3, Table 1.3-1.

¹⁹³ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.9 and Table 4.2.9-1.

¹⁹⁴ Exhibit 3577-X0331, CCA argument, paragraph 89 and Exhibit 3577-X0326, CAPP argument, page 17.

¹⁹⁵ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 105.

¹⁹⁶ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.4, page 1 of 10.

¹⁹⁷ Transcript, Volume 3, page 540.

353. The additional positions proposed in the test period are discussed individually in the table below by labour activity category.¹⁹⁸

Table 18. Forecast additional labour positions, by labour activity category

Labour activity category	Proposed additional position	Additional non-capital FTEs	Proposed hire date	Reason for additional position
Gas control	Control centre operator	2 positions at 0.7 FTEs each	January 2015 June 2015	ATCO Pipelines stated that more resources are required to monitor and control the pipeline network as the system grows and becomes more complex. To illustrate the increasing complexity of the system, ATCO Pipelines provided the number of points monitored by the Control Centre. ¹⁹⁹ The number of points has increased by 21 per cent from 2013 to 2016. According to ATCO Pipelines, it takes three years to develop fully qualified Control Centre operators and ATCO Pipelines faces turnover in the Control Centre due to retirements and competition for skilled resources in Alberta.
	Team leader – gas control operator training	1.0	June 2015	
	SCADA engineer	1.0	May 2015	
Engineering and planning	Group leader - planning	0.3	January 2015	To mentor staff, collaborate with NGTL on Alberta system planning and provide support for project teams executing capital programs.
	Planning engineer/system optimization engineer	1.0	May 2015	To support analysis required to address increasing system hydraulic complexities resulting from changes in supply and demand or from ILI projects and to collaborate with NGTL on Alberta system planning.
	Team leader – land administration	1.0	May 2015	To address increased volumes of developer proposals, issues and questions.
	Senior administration coordinator	0.5	2016	To address additional landowner payments resulting from the change in asset base.
Pipeline operations	Transmission operator	2 positions at 1.0 FTE each	2016	To accommodate the increased operation and maintenance workload associated with facilities being added.
	Damage prevention coordinator	0.5	January 2015	To deal with increasing third party activity around ATCO Pipelines' pipelines. To illustrate the increased activity, ATCO Pipelines provided the number of third party locate requests from 2011 and forecast to 2016. These are forecast to increase 14 per cent in the test period.**
	Emergency response manager	0.5	January 2015	To coordinate the Incident Command System implementation in 2015 and to actively engage emergency response service in the ATCO Pipelines service territory to educate them on ATCO Pipelines facilities in their areas.

¹⁹⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.4, page 1 of 10.

¹⁹⁹ Per ATCO Pipelines' response to UCA IR (Exhibit 3577-X0280, AP-UCA-2015FEB03-052), the number of points is a direct reflection of the number of facilities and/or automated equipment that ATCO Pipelines monitors and controls. Increased costs associated with additional points are due to increased resources to manage, monitor, validate and secure the data. Labour costs may be reduced when using SCADA for monitoring and automation due to a reduction in the frequency of physical contract with a facility required, dispatching of resources, addressing situations remotely and optimizing pipeline operation.

Labour activity category	Proposed additional position	Additional non-capital FTEs	Proposed hire date	Reason for additional position
	Operations engineer	2 positions at 0.5 FTEs each	2015	To address increased compliance and reporting requirements related to pipeline safety initiatives and continued activity around ATCO Pipelines facilities. To illustrate the increased inspection and surveillance by regulators, ATCO Pipelines noted that the Alberta Energy Regulator conducted 58 site inspections in 2013 compared to 27 in 2011. ATCO Pipelines also provided the number of third party crossings from 2011 and forecast to 2016 to illustrate increased activity around ATCO Pipelines facilities. The number of third party crossings is forecast to increase 21 per cent in the test period.**
	Gas quality coordinator	0.7	2015	To address increasing system complexity and growth and the increasing number of inspection locations that must be monitored and reported on.
	Electrician	0.5	Not provided	Driven by system growth and development, increased capital project activity and incremental facilities and systems.
	Standards engineer	0.5	2015	To coordinate the development of ATCO Pipelines' asset management system (discussed further in Section 6.3.1).
	Engineer – asset management	1.0	2015	
Compressor operations	District compressor mechanic	0.8	2016	To address the net addition of 85 measurement and regulating stations (from the NGTL asset swap) which adds compression maintenance work requirements.
Measurement and regulating operations	Process control technologists	2 positions at 0.7 FTEs each	2016	Driven by the 85 additional facilities being acquired in the NGTL asset swap.
Other (Professional/ Management)	HR coordinators	2 positions at 1.0 FTE each	Not provided	To address changing employee demographics which has impacted the need for additional resource planning, recruiting and training. Additionally, these positions will support the recruitment of the additional 46 FTEs and replacements of retirements over the test period.
	Senior communications advisor Calgary	1.0	Not provided	To address incremental public communications and community involvement required to comply with regulator and public expectations.
Accountants	Financial planning accountant	1.0	Not provided	To address the increasing need for planning and reporting to comply with regulatory requirements and internal/external reporting.
	Fixed asset accountant	0.5	Not provided	To support ATCO Pipelines' increased level of capital and the changing pipeline system, to support scoping, design and implementation of a budgeting and planning system and to ensure ATCO Pipelines' financial system are integrated with asset management initiatives.
	Operational planning accountant	1.0	Not provided	To address increased workload as a result of growth and changes in ATCO Pipelines' operations, including requirements under ATCO Pipelines' asset management initiatives.

Labour activity category	Proposed additional position	Additional non-capital FTEs	Proposed hire date	Reason for additional position
Clerical	Accounts payable clerk	1.0	Not provided	To address the increased volume of supplier payments related to ATCO Pipelines' capital program. ATCO Pipelines provided the number of supplier payments to illustrate the increased volume. Supplier payments increased from 25,777 to 32,921 in the last five years. ²⁰⁰
	Purchasing clerk	1.0	Not provided	To support to ATCO Pipelines' purchasing department due to increased competitive procurement bids, formal quotations, the requirement for greater internal documentation and high project management needs.
TOTAL O&M FTEs		22.6		
Capital programs FTEs*		23		

Sources: Exhibit 0007.00.ATCOPIPE-3577, Section 4.2.1, pages 4-9 of 13 and Section 4.2.4, pages 2-10 of 10 and Exhibit 3577-X0280, AP-UCA-2015FEB03-0043(b).

*Capital FTE labour costs are not included in O&M costs. A list of capital FTEs was provided in AP-UCA-2015FEB03-043(c) in Exhibit 3577-X0280 at PDF pages 207-208.

**Per AP-AUC-2015FEB03-082(b) in Exhibit 3577-X0064, ATCO Pipelines has not forecast the level of activity for the assets being acquired from NGTL compared to the level of activity for the assets being transferred to NGTL.

354. ATCO Pipelines provided the proposed hire date for most positions and indicated that the hire dates of personnel is not spread evenly over the two test years but rather, hire dates are forecast using the optimal date relative to the work forecast to be completed by the employees.²⁰¹

355. ATCO Pipelines' increase in FTEs is due to increased activity levels associated with increased capital spending, pipeline integrity work, regulatory compliance obligations and responding to increased public expectations, due to an increased number of retirements during the test period and subsequent years and due to challenges in attraction and retention of resources necessary to ensure execution of all its programs.²⁰²

356. ATCO Pipelines indicated that the two operations engineering positions were filled prior to January 2015.²⁰³

357. ATCO Pipelines anticipates increased turnover going forward and stated in the application that it is preparing for this through a combination of additional positions, increased levels of recruitment, retention and training activities and the proposed asset management program.²⁰⁴

358. ATCO Pipelines anticipates that approximately 20 per cent of ATCO Pipelines employees in leadership positions will retire during the test period and nearly all employees in the defined benefit pension plan will retire within the next 10 years. ATCO Pipelines indicated that 15 per cent of its workforce is eligible to retire in the next five years. ATCO Pipelines indicated that these retirements will result in a loss of knowledge and experience and will result in declining average years of service which will increase the need to train and develop successors

²⁰⁰ Exhibit 3577-X0293, AP-AUC-2015FEB03-092(a).

²⁰¹ Exhibit 3577-X0280, AP-UCA-2015FEB03-047(b).

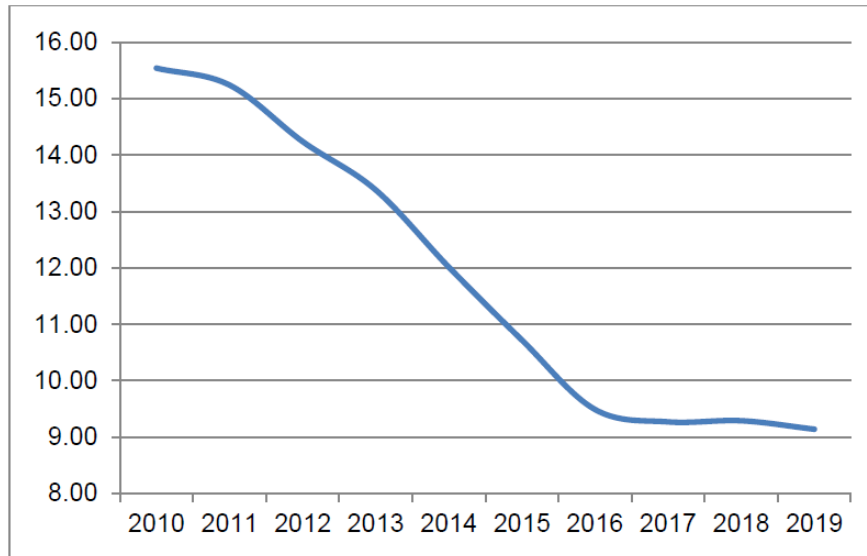
²⁰² Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.3, pages 1 and 5 of 5.

²⁰³ Exhibit 3577-X0064, AP-AUC-2015FEB03-079(a).

²⁰⁴ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.2, page 6 of 6.

to address the gap.²⁰⁵ ATCO Pipelines provided the following chart to illustrate the forecast decline in average years of service:

Figure 1. Average years of service of ATCO Pipelines workforce



Source: Exhibit 0007.00.ATCOPIPE-3577, application, PDF page 123, Chart 4.2.3-2. The underlying information, headcounts, turnover and retirement projections and calculated total years of service, used in determining average years of service for the chart above, was provided in response to AP-UCA-2015MAY21-107(a)-(b).

359. ATCO Pipelines also provided a summary of employees eligible to retire and the actual retirements since 2010:

Table 19. Summary of employees eligible to retire and actual retirements from 2010-2016

	2010	2011	2012	2013	2014	2015	2016
Retirement eligibility	10	13	24	25	26	31	25
Actual retirements	3	6	11	13	12	19*	15*

Source: Exhibit 3577-X0284, AP-AUC-2015MAY21-087.

*Based on history and employee eligibility, ATCO Pipelines has forecast 19 retirements for 2015 and 15 for 2016.

360. ATCO Pipelines relies on a combination of external recruitment and internal succession to address employee change, such as retirements. When ATCO Pipelines hires externally for skill sets not currently available within ATCO Pipelines, external candidates are hired with a skill set and pay level consistent with that of the departing employee. Generally, ATCO Pipelines relies on internal succession planning to address expected retirements so internal candidates are at or just below the level of the departing employee. This results in a cascading impact of internal movements down to entry level positions.²⁰⁶

²⁰⁵ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.3, page 2 of 5.

²⁰⁶ Exhibit 3577-X0280, AP-UCA-2015FEB03-043(a).

361. In argument, CAPP requested that forecast positions that are currently unfilled be disallowed and any positions that have not been filled in a timely manner be removed from ATCO Pipelines' forecast FTEs in the test period.²⁰⁷

362. On November 26, 2015, the CCA submitted a request to suspend the process schedule for one week in order to assess the impact of the recent ATCO companies' announcement of restructuring and employee reductions on ATCO Pipelines' revenue requirement.²⁰⁸ The Commission issued a ruling on November 27, 2015, denying the request. In that ruling, the Commission noted that the effect of employee reductions on ATCO Pipelines' revenue requirement and forecast FTEs for the test period is uncertain and therefore, a placeholder was established for FTEs and their related costs.²⁰⁹

363. In reply argument, the CCA took issue with the ATCO announcement of employee reductions which do not form part of the evidence on the record and argued that the layoffs should have been disclosed by ATCO Pipelines. The CCA provided a list of questions that it proposed should have been asked had ATCO Pipelines properly disclosed the upcoming layoffs and submitted that these should each be addressed by ATCO Pipelines in the compliance filing. The CCA submitted that the Commission's November 27, 2015 ruling does not fully address the impacts of the layoffs because, in the CCA's view, the impacts will go beyond FTEs, and submitted that the compliance filing should include information on all the effects of the restructuring of ATCO and particularly ATCO Pipelines. The CCA also submitted that ATCO Pipelines should be directed to disclose actual positions filled and any further expected layoffs in the test period.²¹⁰

364. Subsequent to the Commission's ruling, the UCA submitted a motion on November 30, 2015, to expand placeholder treatment to include other cost items beyond FTEs. In the UCA's view, if employee reductions are due to a poor economy, then this would also impact the forecasts for supplies inflation and in-scope/out-of-scope labour for the 2016 test year, and the UCA accordingly requested these items also receive placeholder treatment. The UCA further requested placeholder treatment for forecast capital expenditures as, in its submission, employee reductions may affect ATCO Pipelines' ability to execute its capital project plan and ILI work.²¹¹

365. The Commission issued a ruling on December 10, 2015, following submissions from parties, denying the UCA's request. The Commission noted that it must balance the need for further placeholders with the applicant's right to a timely decision based on the prospective forecast and the information filed in the evidentiary portion of the proceeding. Due to the timing of the announced employee reductions, the Commission considered that ATCO Pipelines could not be reasonably expected to update the Commission in this proceeding. The Commission considered that the placeholder treatment afforded FTEs and their related costs allows for a balance between parties opportunity to assess the impact of employee reductions and ATCO Pipelines' right to a timely decision.²¹²

²⁰⁷ Exhibit 3577-X0326, CAPP argument, page 8.

²⁰⁸ Exhibit 3577-X0339, CCA correspondence, November 26, 2015.

²⁰⁹ Exhibit 3577-X0340, AUC letter – CCA request to suspend the process schedule, November 27, 2015.

²¹⁰ Exhibit 3577-X0342, CCA reply argument, pages 3-6 and 8.

²¹¹ Exhibit 3577-X0349, UCA motion re placeholder treatment.

²¹² Exhibit 3577-X0353, AUC letter – Ruling on the UCA motion, December 10, 2015.

Commission findings

366. Given the Commission's November 27, 2015 and December 10, 2015 rulings on the matter of placeholder treatment for FTEs and their related costs, the Commission continues to direct ATCO Pipelines to clearly identify the impact of announced employee reductions on forecast FTEs and revenue requirement for the test years. The FTE costs will continue to be treated as a placeholder until the impact of employee reductions is assessed in the compliance filing to this decision. The Commission considers that ATCO Pipelines can take into account the arguments and reply arguments of interveners in preparing its compliance filing to this decision with respect to FTEs.

367. Further, the Commission notes that adjustments have been directed in other sections of this decision based on the information provided on the record of this proceeding, related to matters such as escalation factors, VPP and vacancy rates, which could address some of the parties concerns that were raised. In light of the Commission's November 27, 2015 and December 10, 2015 rulings, parties may provide evidence and recommendations on further impacts to ATCO Pipelines' revenue requirements from the ATCO Group's announced restructuring on FTEs in the compliance filing to this decision.

6.2.6 Vacancy rates

368. The vacancy rate is determined based on an analysis of vacant O&M positions, using a five-year average, which gives effect to the time lag between a position becoming vacant and the filling of that position. ATCO Pipelines forecasts a vacancy rate of 4.2 per cent for both 2015 and 2016.²¹³

369. ATCO Pipelines provided the following tables to show its calculation of the five-year average, using actual position vacancies from 2009 to 2013:

Table 20. Actual capital vacancy rates for five-year average calculation

Capital	2009	2010	2011	2012	2013	5-year average
Vacant weeks	325.5	426.2	564.1	544.9	569.6	
Position weeks	6,207.4	6,618.1	7,046.4	7,436.9	8,824.5	
Vacancy rate	5.2%	6.4%	8.0%	7.3%	6.5%	6.7%

Table 21. Actual O&M vacancy rates for five-year average calculation

Operating	2009	2010	2011	2012	2013	5-year average
Vacant weeks	300.5	709.5	597.7	321.8	501.0	
Position weeks	10,992.3	10,797.9	11,689.0	12,133.8	12,186.1	
Vacancy rate	2.7%	6.6%	5.1%	2.7%	4.1%	4.2%

Source for tables: Exhibit 3577-X0283, AP-UCA-2015FEB03-054(a)-(c).

²¹³ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.4, pages 2-3 of 4.

370. In the hearing, an ATCO Pipelines witness noted that the calculated vacancy rate reflects historic vacancies and it incorporates positions that are open for a period of time as well as positions that become open due to individuals moving into more senior roles.²¹⁴

371. In response to an IR, ATCO Pipelines recognized that the slowdown in the economy could result in fewer jobs available in the marketplace and could result in a lower vacancy rate compared to the vacancy rate included in the application. For example, ATCO Pipelines has experienced an increase in the number of job applicants for advertised positions. ATCO Pipelines acknowledged that the current vacancy rate of 4.2 per cent is high,²¹⁵ but in the update to its application on June 22, 2015, there were no changes to proposed vacancy rates.²¹⁶

372. In argument, CAPP provided an analysis of vacancy statistics and concluded that ATCO Pipelines' use of a five-year average, under-represents actual vacancies.²¹⁷ CAPP's analysis is reproduced in the following table:

Table 22. CAPP's analysis of ATCO Pipelines vacancies

	2010		2011		2012		2013		2014			
	# pos.	Avg. days vacant	# pos.	Avg. days vacant	# pos.	Avg. days vacant	# pos.	Avg. days vacant	# pos.	Avg. days vacant	Total	Weighted avg. days
Inter-company transfer	4	132.0	17	114.2	12	76.6	5	143.0	3	96.0	41	107.1
External	20	156.0	36	109.6	33	96.7	24	90.8	24	70.1	137	103.1
Internal	12	129.4	19	76.1	20	85.3	22	81.7	24	84.2	97	87.9
To be filled following year	0	0.0	0	0.0	1	61.0	19	150.4	34	157.7	54	153.4
Total	36		72		66		70		85		329	
Vacancies at year end					8	168.0	18	360.2	34			
Deleted	11	272.8	3	179.7	4	139.3	0	0.0	0	0.0	18	227.6
"Blank"	0	0.0	2	144.5	0	0.0	0	0.0	0	0.0	2	144.5
Note: (1) Average days vacant only represent vacant days until the end of the respective calendar year. The 2012 vacancy was still vacant at the end of 2013. (2) The actual days it took to either fill the vacancies at the end of 2012 in 2013-14 or the vacancies at the end of 2013 in 2014. (3) The actual vacancy days for 2014 "To be filled in 2015" are not known as the vacancy fill dates in 2015 were not updated by ATCO Pipelines.												

Source: Exhibit 3577-X0326, CAPP argument, page 9.

373. As a result of this analysis, CAPP concluded that:

- ATCO Pipelines' 5-year average time to replace staff internally is less than 90 days.
- ATCO Pipelines' 5-year average to replace staff externally or by an inter-company transfer is approximately 103-107 days.

²¹⁴ Transcript, Volume 1, page 58.

²¹⁵ Exhibit 3577-X0060, AP-AUC-2015FEB03-002(a)-(e).

²¹⁶ Exhibit 3577-X0179, ATCO Pipelines updated application.

²¹⁷ Exhibit 3577-X0326, CAPP argument, page 9.

- ATCO Pipelines took a significant amount of time to delete positions in 2010-2012.
- ATCO Pipelines takes longer to fill positions which are vacant at year-end than it takes to fill within the year.
- ATCO Pipelines has been able to fill vacancies internally and externally in a timely manner but has not demonstrated it has backfilled new openings.²¹⁸

374. CAPP indicated that ATCO Pipelines continually justifies the need for new positions by stating that it is losing experience to retirements and employee turnover, which results in an increased number of positions to recruit, train and mentor for less experienced employees. In CAPP's view, this issue was brought forward by ATCO Pipelines in the 2013-2014 GRA and therefore ATCO Pipelines has had two years to address it. Further, CAPP noted that the average service years will naturally drop if a long-term employee is replaced with a new hire.²¹⁹

375. CAPP also argued that ATCO Pipelines replaces senior employees with internal employees at or just below the level of the departing employee or with external candidates with consistent skill sets of the departing employee which results in little loss of experience. CAPP indicated that it would appear that ATCO Pipelines has planned for the retirements and has retained senior staff to facilitate training.

376. In reply argument, CAPP stated that actual vacancies or cumulative vacancy data are the sum of the vacant positions and vacancies from delays in hiring new positions, and ATCO Pipelines is not counting unfilled new positions as vacancies. Again, this results in ATCO Pipelines understating its vacancy forecast and seeking to recover wage costs for positions that are actually being deferred by delays in hiring.²²⁰

377. Based on the above, CAPP recommended that ATCO Pipelines be directed to use actual vacancies at the time of the application for 2015 and 2016 vacancy rates, based on the cumulative forecasts of vacancies for new as well as existing positions.²²¹

378. In reply argument, ATCO Pipelines noted that it was directed by the Commission in the last GRA to use a five-year average for forecasting vacancies. Additionally, data for 2013 and 2014 vacancies that forecast FTEs, net of vacancies, were accurate. Furthermore, because 2010 to 2012 were settlement years, they did not have approved FTEs. ATCO Pipelines disagreed with CAPP's argument that departing employees are replaced with external employees of a consistent skill set, saying that at issue is ATCO Pipelines specific experience, not general industry experience.²²²

Commission findings

379. The Commission continues to be of the view that, in general, using a five-year average to calculate the forecast vacancy rate is generally acceptable for the purpose of reflecting the vacancy rate in revenue requirement. However, based on the evidence on the record and the views of the parties, the Commission finds that in certain cases, adjustments could be required to account for anomalies in the current environment. In this case, Alberta's economy has experienced a slowdown which, in ATCO Pipelines' experience, has led to increased

²¹⁸ Exhibit 3577-X0326, CAPP argument, page 9.

²¹⁹ Exhibit 3577-X0326, CAPP argument, page 10.

²²⁰ Exhibit 3577-X0341, CAPP reply argument, page 5.

²²¹ Exhibit 3577-X0326, CAPP argument, page 11 and Exhibit 3577-X0341, CAPP reply argument, page 5.

²²² Exhibit 3577-X0347, ATCO Pipelines reply argument, pages 10-12.

applications for positions. This experience would seem to suggest that there would be a corresponding decrease in vacant positions.

380. However, the Commission has also considered the analysis included in CAPP's argument, which reformulates information on the record, and suggests that ATCO Pipelines under-represented the number of vacancies by not including vacancies that are a result of new positions (positions forecasted to be created in the test period) in the forecast vacancy rate.

381. Given the difficulty in forecasting vacancies due to uncertainties in ATCO Pipelines' operating environment, the Commission continues to consider that using a five-year average of historical rates is a reasonable methodology to estimate vacancy rates. This methodology will be reflective of past experience and should account for variability in vacancy rates due to those fluctuations in ATCO Pipelines' operating environment. Accordingly, the Commission approves ATCO Pipelines' forecast vacancy rate of 4.2 per cent for each of the test years, as filed.

6.3 O&M supplies expenses

382. In the application, ATCO Pipelines provided the following table, which breaks out the components of O&M supplies and shows the actual costs for the previous test period and forecast costs for the current test period:

Table 23. Operations and maintenance supplies

		2013 actual	2014 actual	2015 forecast	2016 forecast
		(\$ million)			
1	Contract services	5.28	5.04	7.23	7.96
2	Utilities	1.41	1.45	2.00	2.21
3	Company vehicles	0.92	0.99	0.98	1.01
4	Fringe benefits	5.05	3.46	3.75	3.88
5	Travel, accommodations, and meals	0.47	0.38	0.50	0.52
6	NGTL asset swap	0.00	0.00	0.00	1.60
7	Materials, equipment, and tools	3.03	3.13	3.12	3.28
8	Year-end accrual adjustment	0.34	(0.34)	0.00	0.00
	Total	16.46	14.11	17.58	20.45

Sources: Exhibit 3577-X00161, AP-AUC-2015MAY21-003 Attachment 3, Schedule 4.2.1-4 and Exhibit 3577-X0064, AP-AUC-2015FEB03-084(a) Attachment.

383. Contract services (or labour) is equal to 41 per cent of O&M supplies in 2015 and 39 per cent in 2016.²²³ Contract services listed in the table above includes costs that ATCO Pipelines incurs through contractors. Contract services are forecast to increase as ATCO Pipelines implements the ICS,²²⁴ an enhanced landowner notification process, and costs associated with external training and communication resources. Additional contract services are also required in the test years due to implementation of the ISO 55001 asset management standard. External consultants will assist ATCO Pipelines with the completion of an asset management gap analysis in 2015 and then with implementation work in 2016 such as implementation of improvements identified through the gap analysis, gap closure plans, and audits required to assure conformance

²²³ Exhibit 3577-X0279, AP-UCA-2015FEB03-031(b).

²²⁴ The ICS is a model used by most major emergency response centres in Alberta. ATCO Pipelines' implementation of its ICS was recommended in the 2014 Certificate of Recognition audit undertaken by ATCO Pipelines and will allow ATCO Pipelines to more effectively interact with other emergency services.

with ISO 55001 and preparations for ISO 55001 certification.²²⁵ ATCO Pipelines' implementation of the ISO 55001 Asset Management standard is discussed further in Section 6.3.1.

384. ATCO Pipelines indicated that utilities costs are forecast to increase due to changing operational needs, specifically increased frequency of injections, a new operations facility in Airdrie and a forecast increase in compressor run hours at ATCO Pipelines' salt caverns storage facility, which is associated with the supply/demand balancing of the Alberta system.²²⁶ Utility costs are forecast based on historical costs, adjusted for any projections for changes in usage and estimated inflation. ATCO Pipelines monitors the pool price when injecting in real-time. However, ATCO Pipelines noted it does not always have the flexibility to alter usage to minimize fuel costs. As a result, ATCO Pipelines forecasts an additional 30 days of withdrawal from and 50 days of injection into its storage facility during the test years²²⁷ ATCO Pipelines also included in its utility costs for the test period \$40,000 in 2015 and \$150,000 in 2016, which are additional costs for the Airdrie operations centre. These costs include utilities, and building maintenance, including snow removal, grounds keeping, waste disposal and cleaning services.²²⁸

385. In response to an IR, ATCO Pipelines provided a table of its fuel cost assumptions for gasoline and diesel. ATCO Pipelines indicated that it does not make a separate assumption for natural gas but rather uses historical averages plus inflation for estimating its building utility costs, which includes natural gas.²²⁹ The table is reproduced below:

Table 24. Fuel cost assumptions

	2015 forecast costs (\$000)				2016 forecast costs (\$000)				Variance (%)
	Unit price (per litre)	O&M	Capital	Total	Unit price (per litre)	O&M	Capital	Total	Total from 2015 to 2016
Fuel costs									
Gasoline	1.09	382	429	811	1.12	393	442	835	2.96%
Diesel	1.37	107	121	228	1.41	111	124	235	3.07%

Source: Exhibit 3577-X0173, AP-UCA-2015MAY21-093(b).

386. The discussion of other major cost items shown in Table 23, which ATCO Pipelines provided variance explanations for, is continued below.

387. The forecast increase for materials, equipment and tools costs reflects inflation and current market pricing for items that are affected by commodities pricing such as nitrogen and compressor oil.²³⁰ ATCO Pipelines does not use a historical average for these costs; prior year activity is reviewed and adjustments are made for one-time expenses and costs are added for system growth, code compliance changes and training requirements.²³¹

²²⁵ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.1, pages 10-11 of 13.

²²⁶ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.1, page 11 of 13.

²²⁷ Exhibit 3577-X0283, AP-UCA-2015FEB03-055(a).

²²⁸ Exhibit 3577-X0283, AP-UCA-2015FEB03-055(b).

²²⁹ Exhibit 3577-X0249, AP-UCA-2015FEB03-028(c).

²³⁰ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.1, page 13 of 13.

²³¹ Exhibit 3577-X0283, AP-UCA-2015FEB03-056(d).

388. Fringe benefit costs include costs such as employment insurance, Workers Compensation Board (WCB), Canada Pension Plan, company pension, employee health and dental plans, group life insurance and post-employment benefits.²³²

389. ATCO Pipelines assumed an inflation rate of 3.0 per cent for supplies. Generally, ATCO Pipelines explained that increases in supplies costs due to inflation were assumed to be 3.0 per cent where specific cost increases could not be estimated for the test years.²³³ The inflation rate was based on Alberta economic assumptions.²³⁴ The assumptions were updated in response to the first round of IRs. ATCO Pipelines explained that a significant component of the supplies costs are for contract services, which are labour based costs. ATCO Pipelines' labour costs are forecast to increase by 3.5 per cent for in-scope personnel, which is reflective of external wage settlements for 2015 and 2016. These factors were used to internally derive the 3.0 per cent escalation which represents ATCO Pipelines management's assessment of an appropriate escalation rate such that it reflects a blend of contract labour and other non-labour costs.²³⁵ Furthermore, Alberta CPI, one of the economic indicators used, was forecast to be 2.0 per cent at the time of the application and more recent forecasts of CPI (at the time of responses to the first round of IRs), were at 1.8 per cent. ATCO Pipelines argued that this is consistent with the CPI per cent used in the application and therefore the assumptions for supplies inflation remains reasonable.²³⁶ Moreover, along with a decline in the economic environment, there has been a significant decline in the value of the Canadian dollar since the application was prepared. ATCO Pipelines has not quantified this impact but stated that this will translate into higher costs to ATCO Pipelines for any services and supplies sourced from the United States.²³⁷

390. In argument, the UCA commented on the declining economic environment in Alberta and ATCO Pipelines' decision not to update its application: "In light of the extraordinary changes to the economic climate in Alberta since the time the data contained in the application was collected, ATCO Pipelines' use of pre-2015 data is of little use and risks misdirecting the Commission as to the true state of affairs faced in the province."²³⁸ The UCA argued that, based on the Commission's previous findings about the need for the best available information, the current proceeding's findings should be based on the most current information available. The UCA argued that 0.9 per cent and 1.6 per cent²³⁹ should be used for supplies escalators in 2015 and 2016 respectively, on the basis that ATCO Pipelines' forecast relies on stale data (from November 2014 and February 2015) and the methodology used to forecast the escalators is unsupported and not reproducible (calculations are not reproducible or testable year-to-year or following extraordinary events, forecasts are based on management's best estimate, and ATCO Pipelines has not adopted any standard measure of inflation).²⁴⁰

²³² Exhibit 3577-X0039, AP-CAL-2015FEB03-052(c).

²³³ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.4, Table 1.4-1.

²³⁴ The economic assumptions include data from Alberta Finance's Fiscal Plan 2014-2017 Economic Outlook available at <http://www.finance.alberta.ca/publications/budget/budget2014/fiscal-plan-economic-outlook.pdf>. ATCO Pipelines included indicators such as nominal economic growth, real economic growth, employment, population, average weekly earnings and Alberta CPI which ATCO Pipelines stated are escalating annually at a rate of 3.5 per cent for 2015 and 2016.

²³⁵ Exhibit 3577-X0249, AP-UCA-2015FEB03-031(a).

²³⁶ Exhibit 3577-X0060, AP-AUC-2015FEB03-002.

²³⁷ Exhibit 3577-X0060, AP-AUC-2015FEB03-002 (a)-(e).

²³⁸ Exhibit 3577-X0333, UCA argument, page 7.

²³⁹ These percentages are from the Alberta Treasury Board and Finance Department's 2015-16 First Quarter Fiscal Update Economic Statement dated August 2015.

²⁴⁰ Exhibit 3577-X0333, UCA argument, pages 8-9.

391. In its reply argument, CAPP supported the UCA's argument that the best available information should be used and supported the UCA's recommendation of a supplies escalator of 0.9 per cent in 2015 and 1.6 per cent in 2016. CAPP noted that ATCO Pipelines made several adjustments to its revenue requirement during the proceeding based on updated information but noticeably absent were adjustments related to labour and supply escalators.²⁴¹

392. The CCA argued that the forecast rate for supplies inflation is excessive given current Statistics Canada Economic Indicators.²⁴² The CCA recommended using the federal government CPI rate of 1.7 per cent for supplies in 2015 and 2016 and that ATCO Pipelines' revenue requirement be adjusted accordingly.²⁴³

393. In reply argument, ATCO Pipelines reiterated that average weekly earnings are not specific to ATCO Pipelines' industry sector while the Mercer evidence is. ATCO Pipelines also noted that its costs are driven by sectors that are still busy despite the general economic climate.²⁴⁴

Commission findings

394. The Commission finds that, in light of the current economic situation in Alberta and given the evidence on the record from independent reports which show decreased forecasts for CPI compared to that submitted by ATCO Pipelines, the proposed supplies inflation assumption of 3.0 per cent is not reflective of current market conditions. The Commission has taken into account the recommendations of the CCA and the UCA and considers that the 0.9 per cent proposed by the UCA is too low given the current exchange rate, which ATCO Pipelines has indicated will translate into increased costs for goods and services procured from the United States.²⁴⁵

395. The Commission, in factoring the current market conditions that are expected to result in lower supplies costs and the counterbalancing current exchange rate, finds that the recommendation of 1.7 per cent for supplies inflation for 2015 and 2016 is reasonable given the current market conditions and the higher exchange rate affecting supply costs. As a result, the Commission directs ATCO Pipelines to use a supplies inflation factor of 1.7 per cent.

6.3.1 International Organization for Standardization (ISO) – International Standards 55001 (asset management)

396. ATCO Pipelines stated that in the 2015-2016 test period, it had retained a third-party expert to undertake a gap analysis to assess its current processes and documentation relative to the ISO 55001 standard. A second deliverable of this effort will be to produce a roadmap for ATCO Pipelines to achieve ISO certification. ATCO Pipelines forecast that internal resources will be required to support the gap analysis and road mapping effort and has included forecast operating costs in the order of \$1.6 million for the third-party consultant and additional internal resources (two FTEs) required for these exercises. ATCO Pipelines is not forecasting costs associated with ISO certification in the 2015-2016 test period.

²⁴¹ Exhibit 3577-X0341, CAPP reply argument, pages 1-2.

²⁴² Statistics Canada reported CPI at annual rate of 1.7 per cent and average weekly earnings are down 1.23 per cent.

²⁴³ Exhibit 3577-X0331, CCA argument, page 27.

²⁴⁴ Exhibit 3577-X0347, ATCO Pipelines reply argument, pages 43 and 46.

²⁴⁵ Exhibit 3577-X0060, AP-AUC-2015FEB03-002.

397. Calgary noted that it had no fundamental objection to the use of ISO 55001, as long as the proper steps were taken for development of an asset management system.²⁴⁶ Calgary argued that until ATCO Pipelines has followed the procedures and processes outlined by ISO standards, and has filed a full and proper business case, the costs of ATCO Pipelines' proposed asset management activities, in the current application, should be disallowed.²⁴⁷

398. Calgary considered that from the following testimony of the ATCO Pipelines witness panel it was clear that ATCO Pipelines did not know where the organization stands in order to become ISO compliant:

At page 86 of Volume 1 of the transcript:

3 The stage the company is at right now is, as
4 Mr. Schmidt will be able to point you out to, **is one**
5 **where we're evaluating where we are with respect to**
6 **ISO 55001 accreditation, and we will go through that**
7 **journey.** One would expect when we go through that
8 journey we're going to find we're at a certain maturity
9 level in terms of where we're at in our processes and
10 documentation, and once we understand where our gaps
11 are for 55001 certification, we'll take the steps to
12 close those gaps and have a process and a system that
13 will stand the test of time.

At page 101 of Volume 1 of the transcript:

3 We firmly believe we are going about this in a
4 very logical plan manner. Our next -- our step in this
5 test period is to understand through a gap analysis
6 where we are relative to the ISO 55001 standard, then
7 provide a road map forward.
8 **Once we have that, as we've described already, we**
9 **will have a much clearer picture on what, if any,**
10 **further work is required.** And as we've already said,
11 we would be before this Commission talking about that
12 in our next application and updating the Commission on
13 where we are at.

At page 256 of Volume 2 of the transcript:

1 **which would give us a maturity rating in the various**
2 **areas of ISO, of our rating in each of the various**
3 **areas of ISO, and that would guide us to where we are**
4 **at a mature level, or where we're not.** And that would
5 be one of the key outcomes we expect from our gap
6 analysis.²⁴⁸ [emphasis added by Calgary]

399. Calgary argued that "... nowhere in any of the ATCO application documents is there one shred of evidence of the tangible cost savings and benefits which ISO 55001 indicates will be

²⁴⁶ Exhibit 3577-X0237, CAL-AUC-2015SEP18-003(a)-(b).

²⁴⁷ Exhibit 3577-X0327, Calgary argument, paragraph 18.

²⁴⁸ Exhibit 3577-X0327, Calgary argument, paragraph 74.

realized from being compliant. Nowhere has ATCO Pipelines undertaken a cost benefit analysis to demonstrate a net benefit to Customers.”²⁴⁹

400. The CCA was concerned about ATCO Pipelines’ expenditures related to pursuing ISO 55001 accreditation. The CCA noted that in cross-examination ATCO Pipelines admitted they had not performed a cost-benefit analysis before proceeding with expenditures related to pursuing and investigating ISO 55001 certification. ATCO Pipelines also conceded that no regulatory body or stakeholder had requested or required that they obtain this certification. The CCA submitted that when asked to describe the benefits of this accreditation, ATCO Pipelines was unable to provide a single specific benefit attributable directly to ISO 55001.

401. The fact that ATCO Pipelines was proposing to hire two full-time positions to pursue its asset management implementation convinced the CCA that this was more than a gap analysis.

402. The CCA recommended that the Commission “... direct AP to suspend all expenditures related to the pursuit of ISO 55001 accreditation. Revenue requirements in any future business case must include a specific comparison of the elements of ISO 55001 and those elements required for AP compliance with the Alberta Energy Regulator’s mandated requirements of CSA standard Z662 Appendix N.” The CCA submitted that customers should not be responsible to pay for incremental expenditures without a complete understanding of the costs and benefits.²⁵⁰

403. The UCA supported both Calgary and the CCA in their positions to deny the expenditures related to an ISO 55001 gap analysis.

404. ATCO Pipelines submitted that upon receipt of the gap analysis it will develop its roadmap to work towards achieving certification.

405. In response to suggestions by Calgary that ATCO Pipelines is putting the “cart before the horse’ by embarking on its ISO 55001 initiative without a detailed cost-benefit analysis, it explained that the costs cannot be known with any degree of accuracy until the initial work involved in a gap analysis and roadmap are completed. ATCO Pipelines also explained that it was sensitive to the need to balance the benefits of ISO 55001 implementation with costs, but the modest ISO 55001 costs included in the GRA were a reasonable first step in exploring the benefits of ISO 55001.

406. In its application and in testimony, ATCO Pipelines explained how the ISO 55001 initiative is expected to compliment, but not replace, its existing asset management systems and would provide a “... framework of check and balance of what we believe we are doing very well today and help form our documentation such that it aligns with an international standard, as opposed to kind of us drinking our own coffee and saying, ‘Yeah, we’re doing a good job.’”²⁵¹

Commission findings

407. The Commission does not object to ATCO Pipelines conducting its “gap analysis” for asset management per se but agrees with Calgary and the CCA that such expenditures for a gap analysis are premature. It is unclear what value the gap analysis will provide to ATCO Pipelines’ asset management in the test years. The costs for the gap analysis and the two FTEs that were

²⁴⁹ Exhibit 3577-X0327, Calgary argument, paragraph 81.

²⁵⁰ Exhibit 3577-X0331, CCA argument, paragraph 11.

²⁵¹ Transcript, Volume 1, page 121, lines 20-25.

forecast in the revenue requirement have not been sufficiently supported. For example, ATCO Pipelines' witness stated in response to the CCA:

Q: ...Is there a cost-benefit analysis?

A. MR. HAHN: You know, Mr. Wachowich, as I think as I pointed out earlier in my analysis, at this stage we are in the evaluation of the maturity level. And so what we're going through is the process to see where we're at, what gaps we would have to 55001. We would look to -- and my friend Mr. Schmidt will point this out more significantly, but we would look to ISO certification outside of the test period, likely in 2017, and will evaluate, after looking at what the gaps are and direction we go, we will evaluate and confirm if that's still the right thing to do.

And at that time a -- I would expect the next time we see you in a forum like this we would have a somewhat more precise idea of what the costs of full implementation of ISO 55001 are. And along with that, re-enforcing the benefits we've outlined in the 11 pages in the application that you referred to.²⁵²

408. The Commission finds with respect to including a gap analysis in revenue requirement for the 2015-2016 test years that:

- ATCO Pipelines has not performed a cost-benefit analysis of spending \$1.6 million to conduct a gap analysis and road map to determine whether to bring forth a future business case for implementation of ISO 55001 certification..
- It is uncertain whether additional ISO 55001 certification will provide a benefit to customers given the existing asset management programs ATCO Pipelines has in place.

409. ISO 55001 certification is not currently required to comply with the standards of any regulatory body. There is also insufficient evidence on the record to support that the program is required in addition to the CSA Z662 standard or to maintain safe or reliable service, but rather, ATCO Pipelines indicated that ISO 55001 would act as a "check and balance."²⁵³

410. Accordingly, the Commission directs ATCO Pipelines to remove the \$1.6 million related to the ISO 55001 from revenue requirement during the test years. ATCO Pipelines may choose to provide a proposal for a gap analysis related to ISO 55001 certification in a future GRA.

411. For other O&M labour and supplies costs which include estimates for specific work related to the asset management system projects, such as the costs included in contract services O&M supplies cost category, ATCO Pipelines is directed to recalculate the O&M labour and supplies costs to reflect the denial of the ISO 55001 project costs for the test period.

²⁵² Transcript, Volume 1, page 89, line 9 to page 90, line 1.

²⁵³ Transcript, Volume 1, page 121, ATCO Pipelines' response to the CCA at lines 7-17, states: "What the ISO 55001 standard does, excuse me, is gives us a protocol in order to check and balance that. So these systems may hold all of the data, but the ISO 55001, should we go to full implementation, gives us a framework to say: Are we checking that? Are we checking it appropriately? What's your audit protocol on that? How often do you check it? And it gives us a road map that's been developed by a third party as opposed to us saying to ourselves, 'Yes, we're good, and we're going to check it in this way.' "

6.4 Administrative and general costs

412. A&G costs are composed of the labour and supplies costs for the general, financial, human resources, corporate communication, regulatory and information management functions of ATCO Pipelines, the costs for legal, audit and consulting services and the costs for insurance, injuries and damages, hearing costs and employee benefits.²⁵⁴

413. In addition to inflation, ATCO Pipelines stated that the key drivers of the forecast increases in the test years are due to:

- Additional financial, regulatory and IT resources required to provide data, analysis and reporting support to additional programs required to address system integrity, reliability and safety and the proposed asset management program.
- Additional resources to support and centralize record keeping requirements established in CSA Z662 and to interface with information systems used for risk management and accounting purposes.
- Additional communication personnel, materials and resources to address increased public expectations for consultation and communication.
- Increased insurance costs, additional recruiting and training support for new hires and succession planning.²⁵⁵

414. As with O&M supplies discussed above, A&G supplies cost increases due to inflation were assumed to be three per cent for each of the test years where specific cost increases could not be estimated.²⁵⁶

415. In the application, ATCO Pipelines provided the following table, which breaks out the components of A&G and the actual and forecast costs:

Table 25. Administration and general expenses by prime account

	2013 actual	2014 actual	2015 forecast	2016 forecast
	(\$000)			
Advertising	732	735	889	935
Administration*	17,442	15,869	19,788	20,721
Special services	1,742	530	1,122	1,060
Insurance	2,141	1,926	2,369	2,486
Employee benefits	3,301	3,177	3,399	3,524
Other admin and general	4,603	4,672	4,825	4,820
Recovery of costs – A&G	(75)	(47)	(47)	(47)
Less disallowed costs	(2,982)	(3,000)	(1,481)	(1,415)
Total	26,904	23,862	30,864	32,084

Source: Exhibit 3577-X0033, AP-CCA-2015FEB03-012(b).

*Note: only the administration category has a labour cost component (per Exhibit 3577-X0039, AP-CAL-2015FEB03-052(l-q) Attachment).

²⁵⁴ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2, page 1 of 4.

²⁵⁵ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.2, pages 1-2 of 6.

²⁵⁶ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.4, Table 1.4-1.

416. The category “other admin and general” was broken down, as follows:

Table 26. Breakdown of other admin and general expenses

	2013 actual	2014 actual	2015 forecast	2016 forecast
	(\$000)			
Employees Participating in Communities (EPIC) match	190	209	216	222
Standby fees	436	318	296	282
AUC operating costs	2,681	2,900	2,900	2,900
Rate case expense	1,150	1,150	1,281	1,281
Other items less than \$1000,000	146	95	132	135
Total	4,603	4,672	4,825	4,820

Source: Exhibit 3577-X0033, AP-CCA-2015FEB03-012(a).

417. In response to an IR, ATCO Pipelines stated that the decrease in A&G from 2013 to 2014 was due to decreases in administration. This was namely due a lower allocation of ATCO corporate costs when the allocation methodology was updated to comply with Decision 2013-111,²⁵⁷ a decrease in special services resulting from lower legal and consulting costs due to fewer regulatory proceedings in 2014, a decrease in insurance due to a one-time WCB credit received in 2014 and a one-time membership credit from ATCO Pipelines’ property insurance provider, and a decrease in employee benefits due to lower pension costs as a result of an updated actuarial valuation for the years 2014-2016. The reductions in administration and employee benefits cost categories that occurred in 2014 are forecast to continue in 2015 and 2016.²⁵⁸

418. The difference between actual costs and approved costs for A&G in 2013 and 2014 were mainly due to lower VPP payment and pension costs, which are subject to deferral treatment. In 2013, the difference was also attributed to a decrease in corporate cost allocations, lower labour and travel expenses due to vacancies and lower relocation and training expenses. In 2014, the difference is also attributed to vacancies and delays in hiring due to long recruiting time, lower IT costs resulting from a greater portion of IT costs supporting capital activities, and the one-time WCB credit.²⁵⁹

419. In argument, CAPP disagreed with A&G costs associated with EPIC match fees, which are “a match for donations” in the amounts of \$216,000 in 2015 and \$222,000 in 2016 and recommended that those costs be disallowed, consistent with past Commission decisions which disallowed ATCO Pipelines corporate donations.²⁶⁰

420. In reply argument, ATCO Pipelines noted that the evidence shows that these costs are included in disallowed donations and sponsorships and that placeholders for disallowed donations and sponsorships are no longer required given the Supreme Court of Canada’s recent decision on pension costs.²⁶¹

²⁵⁷ Decision 2013-111: The ATCO Utilities, Corporate Costs, Proceeding 1920, Application 1608510-1, March 21, 2013.

²⁵⁸ Exhibit 3577-X0283, AP-UCA-2015FEB03-060(a)-(b).

²⁵⁹ Exhibit 3577-X0283, AP-UCA-2015FEB03-061(a).

²⁶⁰ Exhibit 3577-X0326, CAPP argument, page 13.

²⁶¹ Exhibit 3577-X0347, ATCO Pipelines reply argument, page 14.

Commission findings

421. ATCO Pipelines has indicated that EPIC match fees are not included in A&G forecast costs as they are included in disallowed costs. The Commission accepts this explanation and finds that those fees are correctly included in disallowed costs and have not been included in the revenue requirement.

422. The Commission has reviewed the forecast A&G costs and finds that the forecasts are reasonable given the information provided in tables 25 and 26 above and are approved, subject to the findings above regarding supplies inflation. Consistent with the direction on supplies inflation in Section 6.3, the Commission directs ATCO Pipelines to revise its forecast A&G costs to use the approved 1.7 per cent for supplies inflation, where applicable and to provide a revised Table 25 in its compliance filing to this decision.

6.5 IT costs

423. On June 4, 2015, the Commission issued Bulletin 2015-11²⁶² which initiated the ATCO Utilities IT common matters proceeding (Proceeding 20514) to examine IT costs related to the IT services MSAs. ATCO Pipelines was directed to refile certain information related to IT costs in Proceeding 20514. Accordingly, the remaining IT issues to be examined in this proceeding are IT volumes, ATCO Pipelines' planning and governance of its IT architecture and infrastructure and related expenses. The Commission did not remove any records pertaining to other IT matters, which had been submitted prior to issuing Bulletin 2015-11. However, this decision will only examine those IT issues which are at issue in this proceeding.

424. IT services which are charged to operating costs include costs to operate, maintain and distribute existing and new IT applications required by ATCO Pipelines to manage its financial, human resources and operational activities. These services also include charges for the provision of hardware e.g. PCs, laptops, monitors; network, voice (telecommunications), data storage and printing and infrastructure; and ad hoc service requests. Effective January 1, 2015, these services are provided to the ATCO Utilities by Wipro Solutions Canada Limited (Wipro).²⁶³ IT services were previously provided by ATCO I-Tek which was sold to Wipro in September 2014.

425. In response to IRs, ATCO Pipelines provided redacted copies of the previous MSA, between ATCO and ATCO I-Tek,²⁶⁴ and the current MSA between ATCO and Wipro.²⁶⁵

426. In contracting with Wipro, ATCO Pipelines stated that it, and ATCO Group, did not formally document the assessment of the impact of risks and balancing of risks on pricing in the contract. ATCO Pipelines indicated that the Wipro contract was negotiated utilizing expert advice to ensure appropriate balance of risk and value.²⁶⁶ To properly manage the MSA, mechanisms were put in place to allow for the appropriate level of flexibility, change, price

²⁶² Bulletin 2015-11, Initiating the ATCO Utilities information technology common matters proceeding to examine IT costs related to the master services agreements between the ATCO Utilities and Wipro Solutions Canada Limited, June 4, 2015.

²⁶³ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.5, page 1 of 2.

²⁶⁴ Provided in exhibits 3577-X0280, 3577-X0281 and 3577-X0282, AP-UCA-2015FEB03-053(a) Attachment.

²⁶⁵ Provided in exhibits 3577-X0289, 3577-X0290, 3577-X0291, 3577-X0292 and 3577-X0293, AP-AUC-2015FEB03-091(d) Attachment.

²⁶⁶ Exhibit 3577-X0037, AP-CAL-2015FEB03-011(v)-(w).

protection and industry validation along with terms and conditions that protect ATCO Pipelines in the event of non-delivery by the service provider.²⁶⁷

427. ATCO Pipelines further indicated that the Wipro MSA was negotiated such that some risks could be allocated to Wipro so that costs could be controlled. The Wipro MSA addressed changes in market conditions and risks that had occurred from the previous MSA.²⁶⁸ ATCO Pipelines noted however that greater risk to a supplier may lead to increased costs to manage the risk, but does not necessarily imply a greater margin.²⁶⁹

428. In the application, ATCO Pipelines provided the actual IT costs in 2013 and 2014 and the forecast costs for 2015 and 2016. ATCO Pipelines noted that IT costs under ATCO I-Tek were charged under affiliate services until August 2014 and then under supplies from September 2014 onward. The table below was provided by ATCO Pipelines, in support of its IT costs:

Table 27. IT services charged to operations

Service provider	2013 actual	2014 actual	2015 forecast	2016 forecast
	(\$)			
ATCO I-Tek	3,506,000	2,686,925	-	-
Wipro	-	917,419	3,729,000	3,813,000
Total	3,506,000	3,604,384	3,729,000	3,813,000

Source: Exhibit 3577-X0287, AP-CAL-2015FEB03-049(a).

429. ATCO Pipelines explained that its IT costs are forecast to increase in 2015 and 2016 primarily due to costs related to: the implementation of PIMS in late 2014 and higher IT costs to support ATCO Pipelines' growing workforce as a result of pipeline and facility integrity requirements, pipeline and facility system changes, and to deal with the loss of knowledge and experience due to staff retirements and turnover.²⁷⁰ In response to an IR, ATCO Pipelines indicated that Wipro's prices for IT services under the current MSA are less than the prices for IT services under the ATCO I-Tek MSA.²⁷¹

430. In response to an undertaking, ATCO Pipelines provided an analysis of IT O&M and capital indirect labour costs. The undertaking response showed that costs are allocated by user for costs such as user-IDs, licence purchase maintenance, hardware, service requests and voice, while application costs are allocated by application based on use or purpose and infrastructure costs are allocated using a corporate allocation of 65 per cent O&M to 35 per cent capital. The result is that 67 per cent of IT costs, excluding direct capital costs, are direct O&M.²⁷²

431. The IT baseline volumes, forecast from 2015 to 2024, are found in Appendix C of the Wipro MSA.²⁷³

432. In response to an IR, ATCO Pipelines indicated that the change in forecast IT workload from 2014 to 2015 is primarily due to the hosting and asset management fees associated with the

²⁶⁷ Exhibit 3577-X0037, AP-CAL-2015FEB03-016(f).

²⁶⁸ Exhibit 3577-X0037, AP-CAL-2105FEB03-007(a)-(c).

²⁶⁹ Exhibit 3577-X0037, AP-CAL-2015FEB03-011(o).

²⁷⁰ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.5, page 2 of 2.

²⁷¹ Exhibit 3577-X0037, AP-CAL-2015FEB03-012(c).

²⁷² Exhibit 3577-X0305, ATCO Pipelines undertaking, 2014 O&M, page 1.

²⁷³ Exhibit 3577-X0293, AP-AUC-2015FEB03-091(d) Attachment.

implementation of PIMS. The forecast IT workload increases from 2015 to 2016 are due to the hosting and asset management fees associated with the implementation of the capital and O&M budgeting, planning and forecasting system. ATCO Pipelines indicated that the change in forecast IT storage volumes from 2014 to 2015 and from 2015 to 2016 are based on historical volume growth and staff growth.²⁷⁴

433. IT governance structures and ATCO Pipelines' governance responsibilities related to the management of the MSA are found in Schedule P of the amending agreement to the Wipro MSA.²⁷⁵ In response to an IR, ATCO Pipelines stated that it prioritizes its governance activities to ensure that critical application service levels are being met and that ATCO Pipelines and Wipro are complying with their respective obligations under the MSA; ensuring that billing reflects the correct services, volumes and rates and the payment to Wipro is properly authorized; and comparing Wipro baseline volumes to actuals on a monthly basis. ATCO Pipelines governance activities are performed by ATCO Pipelines personnel.²⁷⁶ In response to an IR, ATCO Pipelines confirmed that day-to-day IT-related activities between ATCO Pipelines and Wipro are directed to Wipro's customer support centre, while broader issues are handled through ATCO Pipelines' business technology management group. ATCO Pipelines' business technology management group communicates directly with ATCO Pipelines' client delivery partner in Wipro on a day-to-day basis.²⁷⁷

434. In its argument, Calgary recommended that ATCO Pipelines be directed to: file all IT related volumes as part of an application for all future GRAs, pursue Wipro global project delivery and file a strategy document in the next GRA, reduce IT expenditures to where ATCO Pipelines' metrics fall in the first quartile as measured by KPMG,²⁷⁸ reduce direct capital IT labour volume to a level that aligns with the average of 2013 and 2014, reduce indirect capital IT volumes so that the indirect IT volume to O&M IT volume is equal to the average percentage from 2013 and 2014, and ensure that IT service prices for 2015 should be no higher than those the Commission ordered ATCO Pipelines to apply in 2015 in Decision 2014-169.²⁷⁹ ²⁸⁰ These recommendations are explored individually below.

435. Calgary provided the following observations regarding ATCO Pipelines' IT expenditures:

- ATCO Pipelines used only O&M IT costs from Wipro in its metric, whereas the KPMG metric includes total IT outsource spend as a percentage of revenue and total outsource IT spend per user. Calgary understands that ATCO Pipelines' metric does not include the total of O&M, indirect capital and direct capital contrary to the KPMG metric.

²⁷⁴ Exhibit 3577-X0037, AP-CAL-2015FEB03-004(h)-(i).

²⁷⁵ Exhibit 3577-X0293, AP-AUC-2015FEB03-091(d) Attachment.

²⁷⁶ Exhibit 3577-X0284, AP-CAL-2015FEB03-028(e)-(f).

²⁷⁷ Exhibit 3577-X0286, AP-CAL-2015FEB03-036(b).

²⁷⁸ The KPMG report which reviewed the pricing provisions of the IT MSAs to assess the pricing against fair market value was provided in AP-AUC-CONF-2015FEB03-091(b) Attachment.

²⁷⁹ Decision 2014-169 (Errata): ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009 (2010 Evergreen Application), Proceeding 240, Application 1605338-1, February 6, 2015.

Decision 2014-169 was issued June 13, 2014.

²⁸⁰ Exhibit 3577-X0327, Calgary argument, pages 8-9.

- The metric for ATCO Pipelines outsourcing is close to the peer 75th percentile in terms of the KPMG metrics which indicates that ATCO Pipelines outsourcing costs are high relative to the KPMG peer group.
- ATCO Pipelines' total IT spend as percentage of revenue has increased approximately 30 per cent since 2012, and over that period there had been significant growth in ATCO Pipelines' FTEs, which would be expected to reduce total IT spend per user. However, ATCO Pipelines' total IT spend and FTEs, together with the industry metrics (KPMG and Gartner Group²⁸¹) show that IT spend in the test years is excessive.²⁸²

436. Calgary argued that third-party metrics, such as those from Gartner Group and KPMG, indicate that ATCO Pipelines' overall IT expenditures are excessive. Calgary argued that industry standard metrics are the proper way to gauge whether IT expenditures are reasonable at any point in time or over time. Accordingly, Calgary requested that total IT expenditures be reduced so that the IT spend falls within the first quartile, as specified by KPMG.²⁸³ Calgary argued that it is irrelevant for the Commission to consider capital growth or safety as a driver for IT expenditures.

437. In response to Calgary, ATCO Pipelines referred to its argument and rebuttal evidence where it indicated that the KPMG report is to demonstrate fair market value for Wipro, and it was not intended for benchmarking. Additionally, the KPMG report is a comparison of ATCO Group and its peers, therefore comparison to ATCO Pipelines is not valid. And finally, the KPMG report is not an indicator of ideal IT spend, rather it is a comparison of the level of IT outsourcing efforts of ATCO and its peer group.²⁸⁴

438. ATCO Pipelines indicated that increased IT spend per user is not affected in a similar manner between all categories of total IT spend (O&M, indirect capital and direct capital) and that IT spend per user is growing largely due to increased capital spending.²⁸⁵

439. In reply argument, Calgary submitted that cost per user should fall as the number of users increases because costs are spread over a larger FTE base but also because the larger IT investment should result in greater productivity.²⁸⁶

440. In Calgary's view, the Wipro MSA provides for global services but ATCO Pipelines does not use or optimize global resources, which would impact IT volumes and pricing resulting in lower costs to customers.²⁸⁷ In its rebuttal, ATCO Pipelines indicated that Schedule D of the Wipro MSA contains a provision that limits the amount of Wipro work that can be performed offshore and that sourcing strategy is an issue currently under consideration by ATCO Pipelines and Wipro. ATCO Pipelines stated it takes time to develop Wipro's offshore resources and ATCO Pipelines must establish confidence in Wipro's offshoring capabilities. Finally, while offshore resources tend to be lower than onshore, these savings could be lost through additional

²⁸¹ A current report from the Gartner Group was not provided on the record of this proceeding. Calgary stated in response to CAL-AUC-2015SEP18-008 in Exhibit 237 at PDF page 9: "Calgary understands that the IT industry relied on and uses the metrics of the Gartner Group. Calgary also understands that data in provided by Computer Economics. Calgary does not have a copy of a current report issued by either metrics provider."

²⁸² Exhibit 3577-X0227, Calgary evidence, pages 31-32.

²⁸³ Exhibit 3577-X0327, Calgary argument, pages 26 and 28.

²⁸⁴ Exhibit 3577-X0328, ATCO Pipelines argument, page 59.

²⁸⁵ Exhibit 3577-X0265, ATCO Pipelines rebuttal, page 35.

²⁸⁶ Exhibit 3577-X0343, Calgary reply argument, page 9.

²⁸⁷ Exhibit 3577-X0227, Calgary evidence, page 30.

work due to increased communication and/or oversight requirements.²⁸⁸ Calgary stated that it disagrees and ATCO must have negotiated the global resource provisions in the MSA for a reason. Also, Wipro took on ATCO I-Tek employees who would be familiar with ATCO Pipelines' requirements. In Calgary's view, two years of the 10-year Wipro contract have been used by ATCO Pipelines in "evaluating what it can do."²⁸⁹

441. In reply argument, ATCO Pipelines restated that Wipro is a new provider, after a long history with another IT provider and it will take time to understand Wipro's services and explore their suitability for ATCO Pipelines to ensure there will be no adverse impact to ATCO Pipelines' services and operations. The recommendation to provide a strategy to maximize offshoring makes the assumption that offshoring is always better and there is no evidence to support that position.²⁹⁰

442. With regard to an additional recommendation by Calgary to use pricing from Decision 2014-169, Calgary argued that changing IT providers does not change the effect of the Commission's decision and direction on 2015 IT prices. An application to review and vary the decision was denied and therefore, the decision and its direction remain binding.²⁹¹

443. In reply argument, ATCO Pipelines reiterated that the pricing in this application relates to a new provider. Decision 2014-169 relates only to rates for the prior period and neither it, nor the Commission are bound by the order and directions. ATCO Pipelines submitted that the best evidence at the current time is the level of costs in the Wipro MSA.²⁹²

Commission findings

444. The Commission is cognizant that there is an ongoing ATCO Utilities IT common matters proceeding, Proceeding 20514,²⁹³ that will determine whether the MSA pricing is reasonable. Given that the total forecast IT costs are calculated from the forecast IT volumes and the negotiated IT pricing, total IT costs are to be treated as placeholders in this proceeding, pending a determination in Proceeding 20514.

445. Consistent with the Commissions July 30, 2015 ruling on the record of this proceeding,²⁹⁴ the Commission considers that a determination of whether IT service prices approved in Decision 2014-169 for 2015 is beyond the scope of the current proceeding and is more appropriately dealt with in Proceeding 20514.

²⁸⁸ Exhibit 3577-X0265, ATCO Pipelines rebuttal, pages 39-40.

²⁸⁹ Exhibit 3577-X0327, Calgary argument, pages 33 and 35.

²⁹⁰ Exhibit 3577-X0347, ATCO Pipelines reply argument, page 66.

²⁹¹ Exhibit 3577-X0327, Calgary argument, page 36.

²⁹² Exhibit 3577-X0347, ATCO Pipelines reply argument, PDF pages 64-65.

²⁹³ Proceeding 20514, the ATCO Utilities IT common matters proceeding.

²⁹⁴ Exhibit 3577-X0208, Commission's July 30, 2015 ruling, paragraph 23, where the Commission stated: "Bulletin 2015-11 directed ATCO Pipelines to refile IT responses from Proceeding 3577 onto the record of Proceeding 20514. The Commission did not delete the IT responses from the record of Proceeding 3577 but merely restricted the scope of the proceeding. As a result, these IR responses remain on the record of the proceeding and may be utilized by Calgary for preparing cross-examination of ATCO Pipelines' planning and governance related to its IT architecture and infrastructure and governance-related expenses, but not for the purposes of testing forecast costs of IT governance of services provided by Wipro, or the sourcing or the pricing of IT services provided by Wipro, which will be examined in Proceeding 20514."

446. The Commission considers that the matter brought forward by Calgary with regard to offshore capabilities of Wipro is generally related to pricing, despite Calgary's submissions that, "This is not simply a matter of pricing, but a much broader matter of IT strategy that would likely impact both IT volume and pricing."²⁹⁵ In any event, there is insufficient evidence on the record of this proceeding to evaluate the impact of offshoring on IT volumes or pricing. ATCO Pipelines has indicated that it is in the process of investigating Wipro's offshoring capabilities and how that will impact ATCO Pipelines' services and operations.

447. The Commission considers it reasonable for ATCO Pipelines to investigate the impact of using offshore resources and anticipates that the examination of the MSA may occur in Proceeding 20514. As such, the Commission considers the issue of offshore capabilities of Wipro to be outside the scope of this proceeding and the Commission will not direct ATCO Pipelines to file further information in the compliance filing.

448. The Commission considers that the GRA proceeding remains the appropriate forum in which to examine IT volumes. This is consistent with Decision 2014-169, where the Commission found, "The pricing for ATCO Electric and ATCO Gas, as determined in accordance with this decision, shall be applied to forecasted volumes through each respective utility's GRA/GTA process."²⁹⁶

449. In order to evaluate the forecast IT volumes, to which pricing will be applied as determined in the IT common matters proceeding, it is necessary for all IT related volume data to be filed in the next GRA proceeding.

450. The Commission has examined the evidence on the record for forecast IT volume and has some concerns with the information provided. The increase in IT volumes is largely attributed to staff growth, which in turn, has been attributed to: increased capital spending, increased pipeline integrity work, increased regulatory compliance obligations and responding to increased public expectations, and increased numbers of retirements during the test period and subsequent years. The evidence also shows that IT volumes are largely determined on a per user basis. Given the changes in the economic environment, it is not reasonable to assume that the increased capital spending and increased staff due to retirements will occur at the level originally anticipated by ATCO Pipelines.

451. Additionally, the Commission has denied ATCO Pipelines' forecast costs for the asset management IT capital projects (Hyperion, Maximo Phase 2 and the GIS, PIMS and MMS enhancements), which may have a corresponding impact on IT volumes. The Commission understands that forecast baseline volumes are specified in the Wipro MSA, but for the purposes of this application, directs ATCO Pipelines to submit revised forecast IT volumes in the compliance filing, which take into account the denial of the asset management IT capital projects in this decision and to account for changes in ATCO Pipelines' forecast staffing levels as a result of the recent announcement of employee reductions by the ATCO Group.

452. The Commission further directs ATCO Pipelines to file all of its forecast IT volume data for the test period and actual volumes from the previous test period, in all future GRAs.

²⁹⁵ Exhibit 3577-X0327, Calgary argument, page 30.

²⁹⁶ Decision 2014-169 (Errata), paragraph 468.

6.6 Licence fees

453. ATCO Pipelines submitted that, commencing January 1, 2015, all subsidiaries of ATCO Ltd. were required to pay a fee associated with the fair market value of benefits received from the use of intangibles, set at one per cent of operating profit for each ATCO Ltd. subsidiary. ATCO Pipelines included a licence fee of \$628,000 for 2015 and \$684,000 for 2016 in its application.

454. On October 9, 2015, the Commission issued a ruling determining that a separate process was required to allow parties sufficient time to address the licensing fee and a placeholder of zero dollars was assigned to the licence fee included in this application.²⁹⁷

455. In a letter dated October 28, 2015,²⁹⁸ the Commission determined that the issue of licence fees would be heard in a common licence fee proceeding with ATCO Electric in order to allow the Commission to address the licence fee issues related to both the ATCO Electric GTA and the ATCO Pipelines GRA.²⁹⁹ This matter is currently being heard in Proceeding 21029, which will address ATCO Electric Transmission's 2015-2017 and ATCO Pipelines 2015-2016 licence fees. The Commission directed ATCO Electric and ATCO Pipelines to file a joint licence fee application with the Commission and therefore the Commission makes no determination on the licence fee issue in this application. The Commission directs ATCO Pipelines to include a zero dollar placeholder as directed in the Commission's October 9, 2015 ruling in its compliance filing to this proceeding.

6.7 ATCO Mexico

456. The CCA argued that ATCO Pipelines' involvement with affiliate ATCO Pipelines, S.A de C.V. (ATCO Mexico) who is constructing a pipeline in Mexico, using ATCO Pipelines' personnel that form part of the revenue requirement in this application, is significant and the CCA submitted that in this program ATCO Pipelines is undertaking a record capital program and that greater disclosure regarding this arrangement is required.³⁰⁰ Because of ATCO Pipelines' desire to execute this safety driven work as soon as practical, along with the vacancy levels identified in the proceeding and the experience gap that ATCO Pipelines has identified, the CCA is concerned with the prudence of the allocation of ATCO Pipelines' resources to an affiliate.³⁰¹

457. The CCA requested that the Commission direct ATCO Pipelines to submit a complete disclosure of the regulated company's allocation of resources for ATCO Mexico including the potential use of ATCO Pipelines' control centre, and any processes, procedures or management systems developed by ATCO Pipelines and utilized by the affiliate ATCO Mexico for the proposed duration of this affiliate relationship. Furthermore, the CCA requested that this disclosure include all staffing requirements, including those staff selected to work full-time with ATCO Mexico and any other staff requests that form part of the revenue requirements of the GRA.³⁰²

²⁹⁷ Exhibit 3577-X0276, AUC ruling on UCA motion, October 9, 2015.

²⁹⁸ Exhibit 3577-X0325, AUC letter – Process to address licence fees, October 28, 2015.

²⁹⁹ The Commission established Proceeding 21029 to hear the joint licence fee application.

³⁰⁰ Exhibit 3577-X0331, CCA argument, paragraph 95.

³⁰¹ Exhibit 3577-X0331, CCA argument, paragraph 96.

³⁰² Exhibit 3577-X0331, CCA argument, paragraph 97.

458. ATCO Pipelines explained that it follows its affiliate code of conduct for all dealings with affiliates and that ATCO Mexico is no different. Additionally, ATCO Pipelines stated that it had testified at the hearing that the dollars involved were very modest, that there were only five individuals that were involved and that the majority of the related costs were of a flow-through nature.³⁰³ With respect to the potential use of ATCO Pipelines' control centre, ATCO Pipelines also submitted that this had not yet been determined and that any such potential future involvement would have to go through its prudence determination process, which was no different from any other affiliate arrangement.³⁰⁴

459. ATCO Pipelines submitted that the CCA's request for extensive further information on ATCO Mexico related costs should be denied and that the CCA had the opportunity to explore the affiliate costs in the proceeding. ATCO Pipelines further stated that it is required to complete its annual affiliate code of conduct filings with respect to its affiliate arrangements and that there is no reason to put the burden of producing the type of information requested by the CCA outside of general rate application and code of conduct processes.³⁰⁵

Commission findings

460. The Commission considers that the recommendation of the CCA would increase filing requirements beyond what is currently required from ATCO Pipelines with respect to its affiliates. ATCO Pipelines is required to follow its affiliate code of conduct for all dealings with its affiliates, including ATCO Mexico. Ultimately, the burden of demonstrating to the Commission that its forecast costs are reasonable rests with the utility for those forecast costs related to utility service and those costs related to affiliates. Additionally, it is open to the Commission and interveners through the regulatory process to request additional information that may be required in IRs and through cross-examination to test the allocation of resources to affiliates.

461. The Commission is not convinced at this time that the additional information requested by the CCA is necessary given the information provided by ATCO Pipelines on the record of the proceeding. The record supports that sufficient information has been provided to test the forecast affiliate costs with respect to the test years. Interested parties or the Commission may request further information, as required, in future general rate applications or in future code of conduct proceedings, should further information be required.

7 Return on rate base

462. On March 23, 2015, the Commission issued Decision 2191-D01-2015, the 2013 GCOC decision. In its decision, the Commission approved a generic rate of return on common equity of 8.30 per cent for 2015 for Alberta transmission and distribution utilities, including ATCO Pipelines. The Commission also approved a capital structure of 63 per cent debt and 37 per cent equity for ATCO Pipelines for 2015. The ROE and capital structure were approved on an interim basis for 2016 and each subsequent year thereafter, unless otherwise directed by the Commission.

³⁰³ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraphs 111-114.

³⁰⁴ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 115.

³⁰⁵ Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 116.

7.1 Return on equity and capital structure

463. ATCO Pipelines' updated application included an ROE of 8.30 per cent for 2015 and a capital structure of 37 per cent equity and 63 per cent debt for 2015, as per the Commission's 2013 GCOC decision. ATCO Pipelines submitted that it had included the same ROE and capital structure for 2016 as a placeholder pending the outcome of the 2016 GCOC proceeding.³⁰⁶

Commission findings

464. The Commission finds ATCO Pipelines has incorporated the most recently approved ROE of 8.30 per cent for 2015 into its updated application on a final basis, and for 2016 on an interim basis. The updated application is consistent with the Commission's findings in Decision 2191-D01-2015, the 2013 GCOC decision. The Commission finds ATCO Pipelines' use of the approved capital structure from the 2013 GCOC decision of 63 per cent debt and 37 per cent equity for 2015 on a final basis, and for 2016 on an interim basis, included in ATCO Pipelines' updated application to be consistent with the Commission's findings in Decision 2191-D01-2015. The ROE and capital structure included in ATCO Pipelines' updated application are approved, as filed.

7.2 Costs associated with long-term debt

465. ATCO Pipelines forecast a 2015 long-term debt issue of \$155,000,000 at 4.00 per cent and a 2016 long-term debt issue of \$130,000,000 at 4.65 per cent.³⁰⁷ ATCO Pipelines derived its forecast cost of new debt by using forecast rates for 30-year government of Canada bonds, plus a forecast credit spread. The table below shows ATCO Pipelines updated debt rate forecast:

Table 28. ATCO Pipelines' updated debt rate forecast

	2015	2016
	(%)	
30-year government of Canada bond rate	2.50	3.15
Credit spread	1.50	1.50
Debtenture rate	4.00	4.65

Source: Exhibit 3577-X0064, AP-AUC-2015FEB03-075.

466. In determining the 30-year government of Canada bond rate forecast, CU Inc.³⁰⁸ considered advice and forecasts provided by its capital markets advisors³⁰⁹ and consensus forecasts provided by Consensus Economics Inc. As *Consensus Forecasts* are only provided for 10-year Canada bond rates, an observed differential between the 10-year and the 30-year Canada bond rates was used to derive the 30-year Canada bond rate forecast. Using data from the bank forecasts and the *Consensus Forecasts*, and based on discussions with CU Inc.'s capital markets

³⁰⁶ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 3.1, page 1 of 9.

³⁰⁷ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 3.1, page 1 of 9. At Transcript, Volume 1, page 19, line 19, Mr. Shkrobot clarified that the long-term debt rates in the updated application were inadvertently excluded.

³⁰⁸ ATCO Pipelines is a division of ATCO Gas and Pipelines Ltd., which is a wholly owned subsidiary of CU Inc. CU Inc. is the entity that goes to market to raise debt for ATCO Gas and Pipelines Ltd.

³⁰⁹ Capital markets advisors for ATCO Pipelines are: Bank of Montreal, Royal Bank of Canada, Scotiabank and Toronto Dominion Bank.

advisors, an appropriate range was then determined for the 30-year Canada bond rate. ATCO Pipelines used the mid-point of that range for its 30-year Canada bond rate forecast.³¹⁰

467. To forecast 2015 and 2016 credit spreads, CU Inc. considered data and input from its capital markets advisors as well as actual credit spreads associated with CU Inc.'s recent debenture issues. ATCO Pipelines stated that a reasonable range was then determined and the mid-point of the range is used for ATCO Pipelines' forecast credit spread.³¹¹

468. ATCO Pipelines submitted in argument that its revised debt rate forecast in its updated application of 4.00 per cent for 2015 and 4.65 per cent for 2016 remains reasonable. ATCO Pipelines acknowledged that the Bank of Canada rate had decreased by 25 basis points since the time of its update but explained that at the same time its credit spread had increased by 30 basis points from 150 to 180, effectively offsetting the Bank of Canada increase.³¹²

469. ATCO Pipelines submitted at the oral hearing that it had gone through a debenture issue in July 2015 and had obtained a rate of 3.964 per cent.³¹³

470. The CCA submitted that because CU Inc. mirrors down the debt rate it receives to its subsidiaries, and because the actual rate for 2015 long-term debt costs is known, ATCO Pipelines should use the 3.964 per cent as its forecast cost of debt for 2015.³¹⁴

471. For the 2016 forecast cost of debt, the CCA took issue with ATCO Pipelines' forecasting methodology and argued that the *Consensus Forecasts* are a more reasonable estimate of the long or 30-year bond rate. The *Consensus Forecasts* are the primary forecast used in proceedings such as the generic cost of capital, and the *Consensus Forecasts* are compiled from numerous experts in the field including experts within banks. Therefore, the *Consensus Forecasts* provide a broader measure of opinion than ATCO Pipelines' measure of cost of debt.

472. The CCA also submitted that ATCO Pipelines selects the banks' forecasts that it uses and the fact that it only uses four banks leads to a bias.³¹⁵ The CCA submitted that ATCO Pipelines' forecast is overstated because it takes the mid-point of its range of estimates, not the average. In addition, its forecasts are for the end of the year and because rates are forecast to rise, this leads to an overstatement of the forecast interest rate during the year.³¹⁶ Adjusting ATCO Pipelines' end of 2016 year rate back to mid-year, results in mid-year value of the bank forecast of 2.885 per cent or a 23.5 basis point reduction in the forecast, simply by using the mid-year value.³¹⁷

473. The CCA acknowledged that, with one exception, from 2010 to 2014 the *Consensus Forecasts* have over-forecasted rates. However, the over-forecast is reasonable when compared with the forecasts used by ATCO Pipelines.³¹⁸ The CCA recommended a revised forecast debt rate of 3.99 per cent for 2016, as reflected in the table below:

³¹⁰ Exhibit 3577-X0064, AP-AUC-2015FEB03-075.

³¹¹ Exhibit 3577-X0064, AP-AUC-2015FEB03-075.

³¹² Exhibit 3577-X0328, ATCO Pipelines argument, paragraphs 145-147.

³¹³ Transcript, Volume 1, page 66, lines 14-17.

³¹⁴ Exhibit 3577-X0331, CCA argument, paragraphs 50-52.

³¹⁵ Exhibit 3577-X0331, CCA argument, paragraphs 61 and 64.

³¹⁶ Exhibit 3577-X0331, CCA argument, paragraphs 60 and 62.

³¹⁷ Exhibit 3577-X0331, CCA argument, paragraph 63.

³¹⁸ Exhibit 3577-X0331, CCA argument, paragraphs 65-66.

Table 29. CCA revised debt rate forecast for 2016

Description		2016
		(%)
Consensus forecast, 10-year (Exhibit 3577-X0297)		
December 2015	1.7	
December 2016	2.2	
2016 mid-year	1.95	1.95
10-30 year bond differential (Exhibit 3577-X0064, AP-AUC 75)		0.54
Credit spread (Exhibit 3577-X0064, AP-AUC 75)		1.50
2016 forecast debt rate		3.99

Source: Exhibit 3577-X0331, page 20.

474. The UCA did not oppose ATCO Pipelines' forecast debt rate for 2015 of 4.00 per cent but took exception to the 4.65 per cent forecast for 2016, and stated that the forecast for 2016 was no longer current and had been calculated by ATCO Pipelines using a self-serving methodology. The UCA submitted that ATCO Pipelines had not revised its forecast to reflect any changes to the economic climate since February 2015, including a further interest rate cut by the Bank of Canada in July of 2015.³¹⁹

475. Similar to the CCA, the UCA argued that when looking at long Canada bond rates, ATCO Pipelines only considered an average of the year-end numbers available despite referencing the range for the entire year. The UCA submitted that ATCO Pipelines had admitted that for 2016 all of the banks increased their forecasts towards the end of 2016 and that these forecasts were skewed such that each of the year-end numbers were higher than the forecasts for any other given point in 2016. Further, ATCO Pipelines had not provided an explanation or principled basis for its methodology.³²⁰

476. As was also noted by the CCA, the UCA took issue with ATCO Pipelines' use of a mid-point instead of considering the annual average of the 2016 forecasts for long bonds. The UCA submitted that the Royal Bank of Canada year-end forecast for 2016 of 3.75 per cent, was 75 basis points higher than any other forecast, and therefore had a disproportionate weight in the calculation.³²¹

477. ATCO Pipelines submitted that its historical practice and one that has stood the test of time, has been to consider economic forecasts from its capital markets advisors as well as the *Consensus Forecasts* in determining a reasonable range for the underlying long Canada bond rate forecast. Further, ATCO Pipelines submitted that the four banks it uses represent a good portion of Canada's major chartered banks.³²²

478. ATCO Pipelines explained that the year-end average in its forecast methodology was only shown for illustrative purposes and was not the only quarter considered in determining the appropriate range for the long Canada bond rate forecast, all data points from all quarters as well

³¹⁹ Exhibit 3577-X0333, UCA argument, paragraphs 47-48.

³²⁰ Exhibit 3577-X0333, UCA argument, paragraph 50.

³²¹ Exhibit 3577-X0333, UCA argument, paragraph 52.

³²² Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraphs 94-95.

as the *Consensus Forecasts* were considered and used in determining the range and that the mid-point of the range is in effect a mid-year forecast.³²³

479. ATCO Pipelines submitted that both the CCA and the UCA ignore the increase in credit spreads. ATCO Pipelines pointed to the testimony of its witness:

A. MR. SHKROBOT: But what we've also seen during that period of time in CU, as well as other companies out there, our spreads have increased over the long Canadas, where our spreads came into more of 180 basis point. So it was a balancing – counterbalancing impact where the 25 basis point -- long Canada bond rate went down but offset by an increased spread. And that's why our actual 2015 July debt issue came in at 3.964 percent. So right at the overall level of – was included in our application update of 4 percent.³²⁴

480. ATCO Pipelines stated that its witness was clear that the increase in credit spreads was something that CU Inc. had experienced and that this credit spread was evident in the July 2015 debt issuance.³²⁵

Commission findings

481. The actual cost of ATCO Pipelines debenture issue in July 2015 was 3.964 per cent. As the actual cost of debt for 2015 is known, the Commission approves ATCO Pipelines 2015 forecast cost of debt at its actual cost of debt of 3.964 per cent, on a final basis.

482. With respect to the forecast cost of debt for 2016, although ATCO Pipelines has used the same methodology as it has used historically, given the current change shown in the *Consensus Forecasts* and long Canada bond rate, the Commission has some concerns with ATCO Pipelines' long-term debt forecasts.

483. ATCO Pipelines stated in reply argument:

All data points from all quarters as well as the Consensus Forecast were considered and used in determining an appropriate range for each year in question. As outlined in IR response AP-AUC-2015FEB03-75(a), a range of 1.95% to 3.05% was used to determine the 2015 Long Canada Bond Rate forecast of 2.50%. 1.95% was the low first quarter forecast observed and 3.05% was the high fourth quarter forecast observed. So, the mid-point of the range is in effect a mid-year forecast.³²⁶

484. The Commission is concerned with ATCO Pipelines' use of the mid-point of its range as its long Canada bond rate. Both the CCA and the UCA have suggested that using an average of the long Canada bond rates forecast for the entire year may yield a better forecast, however, in its reply argument ATCO Pipelines did not provide a sufficient explanation on why the approach of the interveners would not yield an adequate forecast for ATCO Pipelines. Additionally, the Commission does not agree with ATCO Pipelines that the mid-point of the range is in effect a mid-year forecast and the Commission finds a more reasonable mid-year forecast would be, for example, to use the year-end bank forecast for 2015 and 2016, calculating the mid-year for each

³²³ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraphs 96 and 176.

³²⁴ Transcript, Volume 2, page 419, lines 10-19.

³²⁵ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 179.

³²⁶ Exhibit 3577-X0347, ATCO Pipelines reply argument, paragraph 96.

bank forecast and then taking a simple average of the mid-year values provided by the four banks.

485. The CCA has submitted that the *Consensus Forecasts* are a more reasonable estimate of the long Canada bond rate and that it is compiled from numerous experts including experts within banks and therefore it is a broader measure of opinion. The CCA acknowledged that over the past four to five years the *Consensus Forecasts* have over-forecast rates, but noted that ATCO Pipelines bank forecasts in this case are even higher than those of the *Consensus Forecasts*.³²⁷ The Commission considers that the *Consensus Forecast* approach of the CCA is more reasonable and it is supported by the evidence on the record, for the reasons that follow.

486. When comparing the most recent consensus forecast data on the record to ATCO Pipelines' forecast long Canada bond rate for 2016, the Commission finds there to be a 66 basis point difference between the two forecasts, as shown in the table below:

Table 30. Comparison of long Canada bond rates

	2016 (%)
ATCO Pipelines long Canada bond rate (Exhibit 3577-X0064, AP-AUC-75)	3.15
2016 mid-year consensus forecast, 10-year (Exhibit 3577-X0297)	1.95
10-30 year bond differential (Exhibit 3577-X0064, AP-AUC-75)	0.54
Implied long Canada bond rate	2.49
Difference	0.66

487. The Commission finds the 66 basis point difference to be material when compared to the current market conditions and therefore does not approve ATCO Pipelines' 2016 debenture forecast. The Commission finds that in this case, and given the variances between historical forecasting and the actual long Canada bond rate and upward bias in rates, the *Consensus Forecasts* are a more reasonable forecast of the long Canada bond rate, and that the most current *Consensus Forecasts* on the record of this proceeding should be used when determining the 2016 debt rate forecast.

488. With respect to the credit spread, the Commission agrees with ATCO Pipelines and finds that the increase in credit spreads was experienced by CU Inc. in its most current July 2015 debt issuance and therefore a credit spread of 180 basis points should be used when determining the 2016 debt rate forecast.

489. For these reasons, the Commission directs ATCO Pipelines to incorporate the 2016 debt rate 4.29 per cent forecast shown in the following table in its compliance filing application:

³²⁷ Exhibit 3577-X0331, CCA argument, paragraph 66.

Table 31. 2016 debt rate forecast

Description		2016
		(%)
Consensus forecast, 10-year (Exhibit 3577-X0297)		
December 2015	1.7	
December 2016	2.2	
2016 mid-year	1.95	1.95
10-30 year bond differential (Exhibit 3677-X0064, AP-AUC-75)		0.54
Credit spread (Transcript, Volume 2, page 419, lines 10-19)		1.80
2016 forecast debt rate		4.29

7.2.1 Debt rate deferral account

490. ATCO Pipelines applied to have its debt rate deferral account discontinued. ATCO Pipelines submitted that the balance for this deferral account to the end of 2014 is an under-recovery of \$20,000. ATCO Pipelines submitted that this deferral account no longer meets the criteria for deferral account treatment, specifically with respect to materiality of the forecast amount and uncertainty regarding accuracy and ability to forecast the amount.³²⁸

491. CAPP did not support ATCO Pipelines' request to discontinue its debt rate deferral account, and argued that ATCO Pipelines continues to over-forecast its debt costs.³²⁹

492. The CCA also did not support this request and submitted that the materiality test is based on the amount forecast and not on the current balance of the deferral account. The CCA stated that in terms of materiality, ATCO Pipelines' forecast of \$155 million and \$130 million in new debt in 2015 and 2016 at 4.00 per cent and 4.65 per cent respectively results in debt issuance amounts and an interest expense in excess of \$6 million each year, which is material.³³⁰

493. ATCO Pipelines provided the following table to demonstrate, in terms of materiality, the under- or over-recovery that occurred in 2013 and 2014:

Table 32. Under-recovery/over-recovery in 2013 and 2014

	2013	2014
Under-recovery/over-recovery	(\$140,000)	\$120,000
Approved revenue requirement	\$182,941,000	\$192,642,000
% of approved revenue requirement	0.08%	0.06%

Source: Exhibit 3577-X0345, ATCO Pipelines reply argument, paragraph 53.

Commission findings

494. In Decision 2013-430, the Commission directed ATCO Pipelines to establish a deferral account for debenture rates, and stated, as follows:

220. ATCO Pipelines was at risk for forecast errors in this item during these test periods, which interveners argued resulted in actual debt interest rates being below forecast. The evidence on the record regarding 2009-2012 demonstrates that ATCO

³²⁸ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 1.3, page 3 of 7.

³²⁹ Exhibit 3577-X0326, CAPP argument, pages 17-18.

³³⁰ Exhibit 3577-X0331, CCA argument, paragraphs 73-74.

Pipelines' forecast debt rates have been above actual debt rates by a material amount. This indicates an ongoing tendency to err on the side of overestimation to protect the utility and customers from likely interest rate forecast errors and uncontrollable risk, the Commission finds that a deferral account for debenture rates should be established for the test period, consistent with Decision 2013-358.^{108 331}

¹⁰⁸ Decision 2013-358: ATCO Electric Ltd. 2013-2014 Transmission General Tariff Application, Proceeding 1989, Application 1608610-1, September 24, 2013.

495. As stated above, the Commission finds ATCO Pipelines debt rate forecasts continue to overestimate debt rates. Although ATCO Pipelines' actual 2015 July debt issue was 3.964 per cent compared to its updated forecast of 4.00 per cent, its 2016 updated forecast of 3.15 per cent for the long Canada bond rate was 66 basis points higher than the 2016 consensus forecast implied long Canada bond rate. Accordingly, the Commission does not approve ATCO Pipelines' request to discontinue its debt rate deferral account for the test years.

8 Deferral and reserve costs and placeholders

496. In Section 1.3 of the application, ATCO Pipelines listed and described all of the reserves and deferral accounts requested. ATCO Pipelines requested the continuation of, revisions to and new reserve accounts and deferral accounts, shown in the table below:

Table 33. Proposed and existing deferral accounts

Deferral account	Description	2014 closing balance (\$)	Settlement amount (\$)
Deduction of deferrals for tax purposes deferral account*	ATCO Pipelines is requesting discontinuance of the practice of collecting/refunding deferred taxes in test years based on the forecast changes in Commission approved deferral balances and replacing this with a deferral account mechanism which captures the tax impact on the differences between the actual and forecast placeholder amounts.	591,000	591,000
NGTL integration costs deferral account	To capture the difference between actual and approved costs and savings related to integration with NGTL. Decision 2013-430 approved the continued use of this deferral account.	346,000	0
NGTL directed growth capital deferral account	To capture revenue requirement impacts of actual major growth capital projects not included in the test year forecast as well as the revenue requirement impact resulting from the variance between actual and approved general – growth project expenditures.	183,000	183,00
Salt cavern working gas deferral account	To collect the difference between the average cost of the Salt cavern working gas inventory and the market price received when gas is sold for withdrawal purposes plus any related transaction costs.	(175,000)	0
Reserve for injuries and damages	To fund injuries and damages expenses.	(175,000)	0

³³¹ Decision 2013-430, paragraph 220.

Deferral account	Description	2014 closing balance (\$)	Settlement amount (\$)
Reserve for regulatory expenses**	ATCO Pipelines is proposing to combine the reporting and recovery of AUC operating fees and hearing costs into a single reserve account. The AUC operating fees deferral account was initially established to capture the difference between actual and forecast AUC operating fees. The reserve for hearing costs was initially established to capture Commission approved hearing costs.	(715,000)	0
VPP deferral account	To collect the difference between actual and approved VPP charged to operations plus the net revenue requirement impact on the variance between actual and approved VPP charges to capital accounts.	(848,000)	(848,000)
2013-2014 pension funding deferral account	To collect the difference between actual and forecast pension payments made for the defined benefit plan including special payments, and the pension funding amounts in ATCO Pipelines' 2013-2014 approved revenue requirement. ATCO Pipelines proposed to settle this account upon receipt of the Supreme Court of Canada ruling and compliance filing decisions from the Commission from ATCO Pipelines' 2013 and 2014 pension applications. The settlement will be incorporated as a one-time adjustment to the monthly revenue requirement billing to NGTL. The pension amounts reflect the 50 per cent CPI COLA adjustment. Disallowed pension amounts are set as placeholders (see Section 8.5 below). ³³²	(1,322,000)	0
Negotiated settlement pension funding deferral	To collect the difference between actual pension payments made and the pension funding amounts included in ATCO Pipelines' 2010-2012 negotiated settlement.	(309,000)	(309,000)
UPR deferral*	To capture the difference between actual and approved UPR additions and asset transfer to ATCO Gas and the resulting impact on ATCO Pipelines' revenue requirement.	(730,000)	(730,000)
Total recovery		(2,553,000)	(512,000)

Source: Assembled from Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.3, pages 1-2 of 7 and Section 5.1, pages 1-14 of 14.

* New deferral account.

**Modified deferral account.

497. One June 22, 2015, ATCO Pipelines provided an update to its application. However, there were no updates to deferral and reserve accounts.³³³

498. ATCO Pipelines proposes to settle the negative \$512,000 balance as a one-time adjustment to ATCO Pipelines' monthly revenue requirement immediately after the Commission approves ATCO Pipelines' compliance filing.³³⁴

499. The deduction of deferrals for tax purposes deferral account and the UPR deferral account are new deferral accounts proposed by ATCO Pipelines to begin in the test period. As discussed in Section 8.3 below, ATCO Pipelines also proposed a new deferral account for regulatory or legislative changes.

500. ATCO Pipelines is requesting discontinuance of two deferral accounts: the AUC operating fees deferral account and the debt rate deferral account. ATCO Pipelines is proposing

³³² Exhibit 3577-X0035, AP-CAPP-2015FEB03-022(a)-(c).

³³³ Exhibit 3577-X0179, ATCO Pipelines updated application.

³³⁴ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 5.1, page 2 of 14.

to include the AUC operating fees in its reserve for hearing costs account starting January 1, 2015. ATCO Pipelines is also proposing to discontinue the debt rate deferral account because it does not meet the criteria for deferral account treatment, specifically materiality of the forecast amount and uncertainty regarding accuracy and ability to forecast the amount.³³⁵ The debt rate deferral account is discussed further in Section 7.2.1. ATCO Pipelines proposed to settle the \$20,000 balance in the debt rate deferral account and the \$581,000 in the AUC operating fees deferral account in the current application.³³⁶

501. ATCO Pipelines indicated that it would flow through any cost variances incurred in the test period due to regulatory or legislative changes that were not known or reasonably foreseeable.³³⁷ This is discussed in Section 8.4 below.

502. ATCO Pipelines is requesting approval to remove deferral account balances from the calculation of NWC and to instead accrue monthly carrying costs on all Commission approved deferral accounts, in accordance with Rule 023: *Rules Respecting Payment of Interest*, similar to the currently approved practice for the Salt Caverns working gas deferral account. ATCO Pipelines submitted that this treatment is consistent with the methodology previously approved for ATCO Electric and ATCO Gas.^{338 339} In response to an IR, ATCO Pipelines provided a financial analysis of the proposed methodology, which showed that the deferral account impact under the proposed methodology is less than the revenue requirement impact under the current methodology.³⁴⁰ ATCO Pipelines asserted this change would protect both ATCO Pipelines and its customers in the event of any significant deferral account balance accumulations not forecast during the test period or changes to the timing of deferral settlements.³⁴¹ This is discussed further in Section 5 on NWC.

503. In evidence, the UCA's consultant expressed concern regarding the "proliferation" of deferral accounts in general. In the UCA consultant's view, deferral accounts shift the risk from the shareholder to the customer. Deferral accounts are subject to a prudence review, however, it is difficult for customers to prove imprudence. The UCA's consultant reiterated the criteria for deferral accounts, which are from Decision 2003-100:

1. Materiality of the forecast amount.
2. Uncertainty regarding the accuracy and ability to forecast the amount.
3. Whether or not the factors affecting the forecast are beyond the utility's control.
4. Whether or not the utility is typically at risk with respect to the forecast amount.³⁴²

³³⁵ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.3, page 3 of 7.

³³⁶ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 5.1, Table 5.1-1.

³³⁷ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.1, page 2 of 2.

³³⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.3, page 3 of 7.

³³⁹ In response to AP-AUC-2015FEB03-030(b) in Exhibit 3577-X0064, ATCO Pipelines referenced Decision 2011-450: ATCO Gas (a Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Proceeding 969, Application 1606822-1, December 5, 2011, at page 215, paragraph 1031 for ATCO Gas and Decision 2013-358 at page 212, paragraph 1022, for where the Commission approved the practice of applying carrying charges on deferral balances.

³⁴⁰ Exhibit 3577-X0064, AP-AUC-2015FEB03-030(a) Attachment.

³⁴¹ Exhibit 3577-X0035, AP-CAPP-2015FEB03-030(a).

³⁴² Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application – Phase I, Application 1292783-1, December 2, 2003, pages 115-16.

504. The UCA consultant's evidence made the following recommendation, "Given the shift of risk, the AUC should be extremely cautious in the approval or continuation of any deferral account."³⁴³

505. In ATCO Pipelines' rebuttal evidence, ATCO Pipelines unequivocally stated that "there is no general proliferation of deferral accounts in the application." ATCO Pipelines' current cost-of-service regulation provides cost certainty to customers and provides ATCO Pipelines with the opportunity to earn a fair return on its investment. It also provides the incentive for ATCO Pipelines to encourage innovation and pursue efficiencies that could, in the short term, result in higher earnings. ATCO Pipelines stated that deferral accounts provide equal protection to customers and utility owners.³⁴⁴

Commission findings

506. The Commission does not agree that there is a general proliferation of deferral accounts in this application. Further, the Commission evaluates each request for new and continuation of existing deferral accounts based on the established criteria from Decision 2003-100 of materiality, uncertainty in cost forecasts, factors beyond the utility's control and risk to the utility, while ensuring costs and benefits are symmetrically applied to the utility and customers.³⁴⁵

507. The Commission accepts ATCO Pipelines' reasons for continuing the deferral accounts included in the application. The Commission approves the amounts shown in Table 33 above, including the forecast amounts, subject to any true-ups or adjustments arising from directions elsewhere in this decision and subject to the following exceptions discussed in the subsections below:

- reserve for injuries and damages
- reserve for regulatory expenses
- deduction of deferrals for tax purposes deferral account
- regulatory or legislative changes deferral account

508. The Commission finds that ATCO Pipelines' proposal to settle deferral account balances as a one-time adjustment to be reasonable and consistent with past treatment for the deferral accounts approved by the Commission and its predecessors.

8.1 Reserve for injuries and damages

509. ATCO Pipelines forecast an expense level of \$213,000 in 2015 and \$214,000 in 2016 related to the reserve for injuries and damages (RID) account and forecast claims or payments of \$301,000 in each test year. This results in a net balance in the RID of negative \$87,000 in 2015 and of \$0 in 2016. The forecast claims amount is based on \$23,000 in auto aggregate expenses and \$278,000 in unspecified incidents based on a five-year historical average of payments from the reserve account. In the application, ATCO Pipelines indicated that the auto aggregate

³⁴³ Exhibit 3577-X0224, R. Bell evidence for UCA, Q33/A33, page 26.

³⁴⁴ Exhibit 3577-X0265, ATCO Pipelines rebuttal evidence, pages 23-25.

³⁴⁵ Decision 2000-9 at page 148, stated the following with respect to symmetry: "The Board agrees that the use of deferral accounts should not be for the sole benefit of either the Company or the customers. Rather they should provide a degree of protection to both the Company and the customer from circumstance beyond their control. The Board expects that the individual mechanisms involved in the use of each deferral account should be applied in a consistent and fair manner in both test years and non-test years. Symmetry must exist between costs and benefits for both the Company and its customers."

expenses are ATCO Pipelines' share of self-insurance for auto claims which are less than \$100,000, which is the deductible for ATCO's auto insurance policy.³⁴⁶ ATCO Pipelines used a five-year average to forecast auto aggregate and unspecified incidents expenses in the RID, consistent with the methodology approved in Decision 2003-100.³⁴⁷

510. ATCO Pipelines provided the following continuity schedule for the RID, from 2012 forward:

Table 34. Reserve for injuries and damages

	2012 actual	2013 actual	2014 estimate	2015 forecast	2016 forecast
	(\$000)				
Opening balance	(302)	420	279	(175)	(87)
Forecast expense		(200)	(200)	(213)	(214)
Deferral settlement, per Decision 2013-430			(281)		
<u>Payments</u>					
Auto Aggregate	19	17	21	23	23
Bittern Lake	498	3	6		
Surface Rights Board Claim (Poole Farms)	205	39			
Unspecified incidents ¹	—	—	—	278	278
	<u>722</u>	<u>59</u>	<u>27</u>	<u>301</u>	<u>301</u>
Closing balance	420	279	(175)	(87)	-

Note 1: Historic five-year average from 2010-2014.

Source: Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.7, Table 4.2.7-1.

511. ATCO Pipelines indicated that any incident that is self-insured is chargeable against the reserve account.³⁴⁸

512. In response to an IR, ATCO Pipelines submitted that, while there was a project that resulted from the 2013 flood where ATCO Pipelines replaced the 323 mm Mainline South at Sheep River, it was not included in the RID. ATCO Pipelines stated that this was consistent with ATCO Pipelines' past practice, was Commission approved regulatory treatment and was in accordance with the Uniform Classification of Account for Natural Gas Utilities. The capital cost of the project was \$2,004,000, which was capitalized by ATCO Pipelines.³⁴⁹

513. In response to an IR, ATCO Pipelines indicated that a surface rights claim included in the RID in 2012 and 2013 related to a landowner's allegation that ATCO Pipelines' pipeline was blocking subsurface water flow, causing it to back-up and flood the property. In ATCO Pipelines' view, this type of expense is appropriately charged against the reserve.³⁵⁰

514. In argument, CAPP recommended that legal costs associated with the Surface Rights Board claim be removed from the RID as they are misclassified as injuries and damages. Further, these expenses inflate ATCO Pipelines' expenses accrued during the test period.

³⁴⁶ Exhibit 3577-X0293, AP-AUC-2015FEB03-093(a).

³⁴⁷ Exhibit 3577-X0035, AP-CAPP-2015FEB03-019(a).

³⁴⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.7, pages 1-2 of 2.

³⁴⁹ Exhibit 3577-X0283, AP-UCA-2015FEB03-062(b)-(c).

³⁵⁰ Exhibit 3577-X0033, AP-CCA-2015FEB03-009(e) Attachment.

515. CAPP also argued that ATCO Pipelines' forecast of the deferral account is inconsistent with past Commission decisions, namely Decision 2003-100 which states: "... The Board is of the opinion that a more reasonable claim level would be two major incidents every ten years, equivalent to one every five years ...". ATCO Pipelines uses a five-year average to calculate the forecast expense. CAPP recommended that ATCO Pipelines be directed to recalculate the forecast expenses using a single incident during the last five years.

516. CAPP also recommended that the outstanding balance of \$175,000 be settled given that the amount is not subject to ongoing proceedings or thresholds. In CAPP's view, ATCO Pipelines has not provided a rationale for why this deferral balance should not be settled.³⁵¹

517. In reply argument, ATCO Pipelines submitted that the legal costs were incurred with respect to a Surface Rights Board claim and excluding them would misrepresent the costs associated with that incident. Additionally, these payments were previously approved for inclusion in the RID in the 2013-2014 GRA.

518. Additionally, ATCO Pipelines argued that a five-year average is reasonable and not dissimilar to the approach of other utilities for calculating RID expenses. ATCO Pipelines noted that the Commission has approved the use of a five-year average for other regulatory uses, such as for calculating the vacancy rate.

519. Finally, ATCO Pipelines argued that CAPP's proposal that the account be settled is inconsistent with the traditional treatment of this account. ATCO Pipelines argued that the rollover of the RID balance is reasonable and consistent with the methodology applied by other utilities. It is not practical or efficient to continually settle an account. The proper methodology for reserve accounts is to roll over balances and aim to zero the account out, on an ongoing basis.³⁵²

Commission findings

520. The Commission has reviewed ATCO Pipelines' proposed expenses and settlements for the RID and has reviewed past decisions related to the RID. In Decision 2003-100, the board stated:

The Board notes that there are two aspects to the RID, the level of the annual charge to the reserve, and the target level of the reserve fund.

...

With respect to the annual charge to the reserve, the Board notes that the estimate provided by ATCO Pipelines assumes that there will be two major incidents every four years, equivalent to one incident every two years. ...Absent other evidence, the Board is of the opinion that a more reasonable claims level would be two major incidents every ten years, equivalent to one every five years.

...

The Board is of the view that it is reasonable to allow the reserve to accumulate enough funds to cover one major claim, or \$1,000,000 every five years. If there is more than one major claim in a five-year period, the reserve fund could experience a deficit. However, the Board is not satisfied that there is a pressing need to bring the reserve to that level within the test period.³⁵³

³⁵¹ Exhibit 3577-X0326, CAPP argument, pages 13-14.

³⁵² Exhibit 3577-X0347, ATCO Pipelines reply argument, pages 15-16.

³⁵³ Decision 2003-100, page 98.

521. In the context of this application, the Commission recognizes that its predecessor, the Alberta Energy and Utilities Board, directed ATCO Pipelines to estimate the annual charge to the reserve fund based on one incident every five years. However, given the submissions of interveners, the Commission is cognizant that the environment in which that direction was made has changed and may not be the optimum methodology going-forward. However, consistent with past findings that a five-year average is optimal for estimates³⁵⁴ when specific costs are not available, the Commission finds it reasonable for ATCO Pipelines to use a five-year average to estimate unspecified incidents in the RID. In its next GRA, ATCO Pipelines is directed to provide an analysis of whether the five-year average remains the optimal methodology for the RID.

522. Given the board's previous view that accumulating funds are sufficient to cover incidents related to the RID, the Commission finds that it is not necessary for ATCO Pipelines to settle the account balance of \$87,000 in 2015.

523. With regard to the inclusion of legal fees and the Bittern Lake Surface Rights Board claim expenses in the RID, in Decision 2013-430, the Commission stated the following:

342. ... Intervenors did not question the quantum of the Bittern Lake internal reclamation costs of \$498,000 and offered no alternative means to recover these costs. Absent any evidence that shows an alternative approach to recover these costs, the Commission accepts ATCO Pipelines' explanation that the Bittern Lake reclamation costs of \$498,000 are self-insured costs which should be included in ATCO Pipelines' RID account. ATCO Pipelines' RID expenses forecast for the 2013 and 2014 test years are approved as filed.³⁵⁵

524. Accordingly, the Commission considers that the Bittern Lake claim with the Surface Rights Board has already been approved for inclusion in the RID and therefore will not direct ATCO Pipelines to remove the associated legal fees from the RID. For future costs that may result from Surface Rights Board claims, or other regulatory proceedings that may result in legal or other costs, ATCO Pipelines is directed to identify and explain whether these costs should appropriately be included in the RID, or whether the costs are more appropriately included in a different, or separate, deferral account.

525. For the above reasons, ATCO Pipelines' application with respect to the RID is approved, as filed.

8.2 Reserve for regulatory expenses

526. ATCO Pipelines applied to combine the reporting and recovery of AUC operating fees and hearing costs into a single reserve account, effective January 1, 2015, similar to the treatment of these expenses for ATCO Electric and ATCO Gas.

³⁵⁴ For example, in Decision 3539-D01-2015, the Commission directed EDTI to use a five-year average to estimate life cycle project costs when the project scope is not defined. Also, in Decision 2013-430, the Commission directed ATCO Pipelines to use a five-year average for calculating vacancy rates as it is more reflective of past experience.

³⁵⁵ Decision 2013-430, at paragraph 342.

527. ATCO Pipelines proposed to settle the balance in the AUC operating fees deferral account but to leave a balance in the reserve for hearing costs, which will be carried over in the new reserve for regulatory expenses.³⁵⁶ ATCO Pipelines proposed that the new regulatory expense reserve account will be treated the same as the former hearing cost reserve account, namely, that the balance is incorporated into the determination of the forecast expense recovery for the test period.³⁵⁷

528. ATCO Pipelines provided the following continuity schedule for the reserve for regulatory expenses, from 2013 forward:

Table 35. Reserve for regulatory expenses

	2013 actual	2014 actual	2015 forecast	2016 forecast
	(\$000)			
Opening balance	(938)	(1,682)	1,314	2,152
Expense accrual				
AUC operating fees	(2,500)	(2,500)	(2,900)	(2,900)
Hearing costs	<u>(1,150)</u>	<u>(1,150)</u>	<u>(1,281)</u>	<u>(1,281)</u>
	<u>(3,650)</u>	<u>(3,650)</u>	<u>(4,181)</u>	<u>(4,181)</u>
Deferral settlement	-	842 ¹	(581) ²	-
Payments				
AUC operating fees	2,681	2,900	2,900	2,900
Hearing costs	<u>225</u>	<u>2,904</u>	<u>2,700</u>	<u>577</u>
	<u>2,906</u>	<u>5,804</u>	<u>5,600</u>	<u>3,477</u>
Closing balance	<u>(1,682)</u>	<u>1,314</u>	<u>2,152</u>	<u>1,448</u>

Note 1: Hearing cost deferral settlement, Decision 2013-430.

Note 2: Request AUC admin fees deferral account settlement, see Section 5.1.

Source: Exhibit 3577-X0314, undertaking, updated Table 4.2.6-1, page 1.

529. ATCO Pipelines forecast an expense of \$4,181,000 in each test year and indicated that any accumulated reserve balance at the end of 2016 will be brought forward and used in the determination of the expense forecast in the next GRA application.³⁵⁸ ATCO Pipelines has set expenses, payments and settlements in such a way that there will be a balance of zero at the end of the test period.³⁵⁹

530. Forecast payments for the test period include AUC operating fees, consistent with 2014 levels, in addition to ATCO Pipelines' estimate of approved hearing cost claims.³⁶⁰ ATCO Pipelines' estimates for hearing costs are based on historic spend for similar proceedings.³⁶¹

³⁵⁶ See "balance to settle" in Exhibit 0007.00.ATCOPIPE-3577, the application, in tables 5.1-10 and 5.1-11 on PDF pages 173-174. Also, see response to AP-CAPP-2015FEB03-027(e) in Exhibit 3577-X0035 at PDF page 158.

³⁵⁷ Exhibit 3577-X0035, AP-CAPP-2015FEB03-027(e).

³⁵⁸ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.6, page 1 of 1.

³⁵⁹ Exhibit 3577-X0035, AP-CAPP-2015FEB03-027(g).

³⁶⁰ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.6, page 1 of 1.

³⁶¹ Exhibit 3577-X0033, AP-CCA-2015FEB03-014(a).

531. In response to an IR, ATCO Pipelines indicated that it had provided the individual components of each category of the reserve account and the deferral account. In its view, incorporating the AUC operating fees deferral account into the reserve for hearing costs will maintain costs transparency but eliminate the need for administration of one deferral account (for example: the AUC operating fees deferral account).³⁶²

532. CAPP argued that ATCO Pipelines failed to provide a rationale for not settling its reserve for hearing costs in this application. CAPP recommended that ATCO Pipelines be required to settle the outstanding balances in both accounts, in a consistent manner.³⁶³

533. In reply argument, ATCO Pipelines submitted that the existing process for settling balances should be maintained in the test period, while it transitioned to a combined deferral account. ATCO Pipelines noted that going forward, regulatory expenses and the AUC operating fees will be combined and settled in a consistent manner.³⁶⁴

Commission findings

534. The Commission considers that there is sufficient explanation on the record regarding the benefits of combining the AUC operating fees deferral account and hearing costs reserve account. Further, the proposal to combine the accounts would appear to reduce the number of deferral accounts that ATCO Pipelines is required to manage, and therefore, would create regulatory efficiency. The Commission finds that combining the two accounts is not expected to result in harm to the utility or to the public. The combining of the two deferral accounts into a single deferral account is approved. To ensure transparency and to allow for the continued identification of AUC operating costs within the account, ATCO Pipelines is directed to record separately, AUC operating costs and hearing costs, within the combined deferral account.

535. With regard to CAPP's recommendation that the hearing costs be settled simultaneously with the settling of AUC operating fees when combining the accounts, the Commission finds that this would assist in the tracking of costs included in the combined reserve account going-forward. The Commission therefore directs ATCO Pipelines to include the settlement of the AUC operating fees and hearing costs in its compliance filing, to recalculate the proposed settlement amount and to advise if there is any change to the proposed one-time adjustment for the settlement balance from the amount proposed in the application.

8.3 Deduction of deferrals for tax purposes deferral account

536. ATCO Pipelines included an adjustment to utility tax expense which reflects the deferred taxes payable or refundable as a result of changes in the regulatory deferral account balances. The collection of deferred taxes on regulatory deferral account balances was put in place to ensure both customers and ATCO Pipelines were kept whole from the tax impact resulting from the timing of deferral settlements.³⁶⁵

537. ATCO Pipelines applied to discontinue the practice of collecting or refunding deferred taxes on deferral balances and to replace it with a deferral account for addback or deduction of

³⁶² Exhibit 3577-X0035, AP-CAPP-2015FEB03-027(c).

³⁶³ Exhibit 3577-X0326, CAPP argument, page 13.

³⁶⁴ Exhibit 3577-X0347, ATCO Pipelines reply argument, page 15.

³⁶⁵ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 8.1, page 6 of 8.

deferrals for income taxes.³⁶⁶ ATCO Pipelines indicated that the proposed methodology is consistent with the treatment approved by the Commission for ATCO Electric.³⁶⁷

538. There are no deferrals included in the application for the test years as the amounts in the application form the basis for calculating the deferral amounts. There will likely be actual deferral amounts in the test years and therefore there will be either a tax deduction or addback on ATCO Pipelines corporate tax returns for those years, which ATCO Pipelines has proposed be treated as deferrals. ATCO Pipelines has included placeholders for a tax deduction of \$2,713,000 in 2015 and an addback of \$591,000 in 2016. Once the actual deductions or addbacks for the test years are determined, ATCO Pipelines will calculate the income tax impact by multiplying the difference between the actuals and placeholders by the appropriate income tax rates for the year in question. This income tax impact will then be grossed up for the income taxes and the amounts will either be refunded to or collected from customers.³⁶⁸

539. To transition to the new methodology, ATCO Pipelines applied to settle the accumulated deferred tax liability/receivable as at December 31, 2014, as a collection of \$591,000.³⁶⁹

540. ATCO Pipelines provided the following schedule for the deferred taxes on accumulated deferral balances:

Table 36. Deferred taxes on accumulated deferral balances as at December 31, 2014

	2014 actual	Balance to settle
	(\$000)	
Deferred liability ¹	1,722	
Combined federal/provincial tax rate	25%	
Deferred tax balance (a)	443	
Gross-up for tax ²	<u>591</u>	<u>591</u>

Note 1: From Table 4.5.-2.3 line 26 in the application, Exhibit 0007.00.ATCOPIPE-3577, Section 4.5, page 6 of 6.

Note 2: Gross-up = (a) / (1-tax rate).

Source: Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 5.1, page 14 of 14.

541. On July 30, 2015, the Commission issued Bulletin 2015-13³⁷⁰ which initiated a generic proceeding to address the income tax methodologies used in revenue requirement calculations for regulated utilities in Alberta. The generic proceeding was assigned proceeding number 20687 and is currently ongoing. The generic proceeding is to include, among other issues, consideration of new methods or treatments for income tax identified by parties, such as method or treatments for income tax used in other jurisdictions, and whether utilities should be assumed to claim the maximum allowable deductions for income tax purposes in determining the income tax amount to be included in the revenue requirement.³⁷¹

542. The deduction of deferrals for tax purposes was not addressed in intervener arguments.

³⁶⁶ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 5.1, page 14 of 14.

³⁶⁷ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 8.1, page 7 of 8.

³⁶⁸ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 8.1, page 7 of 8.

³⁶⁹ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 5.1, page 14 of 14.

³⁷⁰ Bulletin 2015-13, Initiating a generic proceeding to address the income tax methodologies used in revenue requirement calculations for regulated utilities in Alberta, July 30, 2015.

³⁷¹ Bulletin 2015-13, scope items 1(i) and 1(v).

Commission findings

543. The Commission considers that given the ongoing generic proceeding to address tax methodologies for regulated utilities, it is premature to approve ATCO Pipelines' proposal for a deduction of deferrals for tax purposes deferral account. Therefore, the Commission directs ATCO Pipelines to continue its practice of collecting or refunding deferred taxes on deferral balances for the test period.

544. The Commission approves a settlement balance of \$591,000 for deferred taxes on accumulated deferral balances as at December 31, 2014. The Commission also approves ATCO Pipelines' placeholders for a 2015 tax deduction and a 2016 tax addback to be used in the calculation of deferred taxes for the purposes of determining its revenue requirement.

8.4 Regulatory or legislative changes deferral account

545. In the application, ATCO Pipelines stated the following, "Any cost variances due to regulatory or legislative changes that were not known of or otherwise reasonably foreseeable to be incurred during the test period shall be flowed through to customers."³⁷² No other mention is made of this item in the application nor in the updated application filed on June 22, 2015.³⁷³

546. In response to information requests, ATCO Pipelines clarified that it is applying for a new deferral account for cost increases or reductions that are the direct result of regulatory or legislative changes not contemplated in this application.³⁷⁴ The deferral account is intended to provide protection to ATCO Pipelines and its customers from the potential impact of changes in regulation or legislation that may arise during the test period. ATCO Pipelines indicated that regulatory and legislative changes may include new tax measures or compliance costs associated with new or amended regulatory requirements not anticipated in the application.³⁷⁵

547. ATCO Pipelines does not consider that this deferral account request warrants any change to its approved ROE or equity thickness.³⁷⁶

548. In argument, CAPP recommended that ATCO Pipelines' request for this deferral account be denied for the test period. CAPP recommended that the impact of this account be assessed when settling ATCO Pipelines' next ROE. CAPP disagreed with ATCO Pipelines' statement that this new deferral account would not warrant a change in the approved ROE and equity thickness because it fundamentally changes ATCO Pipelines' risk.³⁷⁷ In its reply argument, the UCA supported CAPP recommendations. The UCA noted that adopting this deferral account would reduce the risk for which ATCO Pipelines is currently compensated in its approved ROE and deemed capital structure and could result in overcompensation for ATCO Pipelines.³⁷⁸

549. In reply argument, ATCO Pipelines noted that CAPP did not oppose the deferral account but rather requested that it be considered in conjunction with ATCO Pipelines' next ROE proceeding. ATCO Pipelines reiterated that "... this account will not change ATCO Pipelines'

³⁷² Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 1.3, page 3 of 7.

³⁷³ Exhibit 3577-X0179, ATCO Pipelines updated application.

³⁷⁴ Exhibit 3577-X0033, AP-CCA-2015FEB03-004(a)-(d).

³⁷⁵ Exhibit 3577-X0172, AP-CCA-2015MAY21-044(c).

³⁷⁶ Exhibit 3577-X0172, AP-CCA-2015MAY21-043(a)-(b).

³⁷⁷ Exhibit 3577-X0326, CAPP argument, page 18.

³⁷⁸ Exhibit 3577-X0346, UCA reply argument, page 18.

business risk as it operates symmetrically. Regulatory or legislative changes may impact costs negatively or positively.”³⁷⁹

Commission findings

550. In Decision 2013-430, the Commission, citing Decision 2003-100, which was referenced above in Section 4.5.1.1 (paragraphs 151-152), provided the criteria to be considered for whether deferral account treatment should be used.

551. There is no evidence on the record of this proceeding with regard to a forecast amount that is expected to result from the impact of regulatory and legislative changes. Nor is there any evidence which addresses uncertainty regarding the accuracy and ability to forecast the amount with respect to income tax or other legislative changes. The Commission considers that, without this information, it cannot make a determination on whether the requested deferral account meets the first two criteria.

552. The Commission considers that regulatory and legislative changes in many cases would be beyond the utility’s direct control however, the Commission notes that such changes are not typically made without consultation with stakeholders, including ATCO Pipelines. Nor is the risk of regulatory or legislative changes new to ATCO Pipelines, as a regulated utility, and these changes may be addressed as they occur. Regulatory and legislative changes are typically announced prior to implementation and typically take time to be implemented. This generally allows for utilities to take steps to mitigate or plan for impacts from the regulatory and legislative changes.

553. For these reasons, the Commission finds that ATCO Pipelines has not sufficiently demonstrated the need for a regulatory and legislative changes deferral account. Accordingly, ATCO Pipelines’ request is denied.

8.5 Placeholders

554. ATCO Pipelines has included a number of placeholders in its application to account for proceedings currently before the Commission. In particular, ATCO Pipelines included a placeholder of 37 per cent equity and a placeholder for a return on equity of 8.3 per cent for 2016, pending the Commission’s determination in Proceeding 20622.³⁸⁰ These placeholders are discussed in Section 7.1 of this decision.

555. ATCO Pipelines submitted that it was awaiting the outcome of the Supreme Court of Canada’s hearing of the ATCO Utilities’ (ATCO Electric, ATCO Gas, and ATCO Pipelines) appeal of the Commission’s 2011 pension decision,³⁸¹ and as such requested placeholder treatment for its disallowed pension related (COLA) costs.³⁸² In the application, ATCO Pipelines applied for a disallowed pension related (COLA) costs placeholder of zero for 2015 and 2016.³⁸³

556. On September 25, 2015, the Supreme Court of Canada rendered Decision 2015 SCC 45, which denied ATCO Gas and Pipelines’ and ATCO Electric’s recovery of pension related costs. Decision 2015 SCC 45 found “that it was not unreasonable for the Commission to direct the

³⁷⁹ Exhibit 3577-X0347, ATCO Pipelines reply argument, page 18.

³⁸⁰ Proceeding 20622, 2016 GCOC.

³⁸¹ 2011 Pension Common Matters.

³⁸² Exhibit 3577-X0179, ATCO Pipelines updated application, Section 1.3, page 5 of 7.

³⁸³ Exhibit 0007.00.ATCOPIPE-3577, ATCO Pipelines application, Section 4.2.11, page 1 of 2.

ATCO Utilities to reduce their pension costs incorporated into revenue requirements by restricting annual COLA to 50 percent of CPI (up to a maximum of 3 percent) for current service costs from 2012 onward and for special payments addressing the unfunded liability from 2013 onward.³⁸⁴

557. ATCO Pipelines indicated that the ATCO Utilities appeal may also address the issue of recovery of costs in general, and therefore, ATCO Pipelines was requesting placeholder treatment for other currently disallowed operating costs.³⁸⁵

558. A summary of ATCO Pipelines' placeholder requests are summarized in the table below:

Table 37. Summary of placeholder requests included in the June 22, 2015 application update

	2015 forecast	2016 forecast
	(\$000)	
Return		
Equity thickness (%)		37%
ROE (%)		8.3%
Pension costs		
Defined benefit pension costs/special payments	3,377	3,377
Less 50% COLA reduction	(818)	(818)
Net	2,559	2,559
NGTL integration costs		
Plant in service	0	0
Accumulated depreciation	0	0
Contributions in aid of construction	0	0
Depreciation expense	0	0
Income taxes	0	0
Non-monetary adjustment	0	0
Monetary adjustments	0	0
UPR		
Capital expenditures	198,987	138,000
Growth capital		
Inland loop project	8,250	46,625
Other major projects	0	0
Growth – general	2,125	2,125
Income taxes		
Deduction/(addbacks) of deferrals for tax purposes	2,713	(571)
Reserves		
Regulatory expenses	4,181	4,181
Injuries and damages	213	214

³⁸⁴ *ATCO Gas and Pipelines Ltd. v. Alberta* (Utilities Commission), 2015 SCC 45, paragraph 65.

³⁸⁵ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 1.3, pages 4-5 of 7.

	2015 forecast	2016 forecast
	(\$000)	
Other placeholder requests		
Disallowed COLA costs	818	818
MTIP/LTIP	711	632
Donations and sponsorships	418	430
Corporate costs	80	81

559. ATCO Pipelines clarified that the disallowed pension cost placeholders are part of the total disallowances deducted from ATCO Pipelines' revenue requirement for 2015-2016 which is separate from, but consistent with, the placeholders for the 2013 and 2014 pension costs.³⁸⁶

560. The Commission issued Decision 2954-D01-2015 on January 15, 2015 regarding the ATCO Utilities' 2013 pension application. The Supreme Court of Canada released its decision on the ATCO Utilities' appeal on September 25, 2015. As a result of these decisions, ATCO Pipelines clarified that the applied for placeholders are no longer required, with the exception of the 2014 pension funding and the placeholder required for ROE and equity thickness, pending the outcome of the 2016 GCOC proceeding.³⁸⁷

561. In argument, CAPP recommended that the placeholders for disallowed operating costs be removed. CAPP argued that the costs related to MTIP/LTIP, donations and sponsorships and corporate costs were not subject to the Supreme Court of Canada appeal and were previously disallowed. Further, the Supreme Court of Canada did not rule in favour of the ATCO companies in its decision and therefore the placeholders should be disallowed. CAPP noted that, in the oral hearing, the ATCO Pipelines witness stated that the placeholders are no longer required, with the exception of the placeholder for pensions, which is required because of the ongoing 2014 pension costs proceeding.³⁸⁸

562. In argument, the CCA submitted that no placeholders should be allowed for previously disallowed items. The CCA further stated that placeholders undermine regulatory policy developed over the course of various proceedings. Accordingly, the CCA recommend that the Commission deny ATCO Pipelines' request for placeholder amounts on disallowed items.³⁸⁹

563. In reply argument, ATCO Pipelines agreed with CAPP and the CCA that the disallowed operating costs placeholders are no longer required.³⁹⁰

Commission findings

564. The placeholders requested in ATCO Pipelines' application include:

- exchange of asset costs related to the NGTL integration, which will be captured in the NGTL integration deferral account
- capital project costs which will be captured in the capital growth deferral account
- UPR capital expenditures which will be captured in the UPR deferral account
- income tax deductions/addbacks, which will be captured in the deductions of deferrals for income tax purposes deferral account

³⁸⁶ Exhibit 3577-X0035, AP-CAPP-2015FEB03-029(a).

³⁸⁷ Exhibit 3577-X0328, ATCO Pipelines argument, pages 98-99.

³⁸⁸ Exhibit 3577-X0326, CAPP argument, pages 16-17.

³⁸⁹ Exhibit 3577-X0331, CCA argument, page 29.

³⁹⁰ Exhibit 3577-X0347, ATCO Pipelines reply argument, pages 17 and 51.

- injuries and damages which will be captured in reserve accounts
- disallowed COLA costs
- MTIP/LTIP
- donations and sponsorships
- corporate costs

565. Findings for the pension costs placeholders are addressed in Section 6.2.4, findings for the NGTL integration costs are addressed in sections 6 and 8, findings for the UPR capital expenditures placeholders are addressed in Section 4.5.1.1, findings for the growth capital inland looping project placeholder are addressed in Section 4.5.2, findings for the other NGTL directed growth capital projects are addressed in Section 8, findings for income taxes deductions/addbacks of deferrals for tax purposes are addressed in Section 8.3, findings for regulatory expenses are addressed in Section 8.2 and findings for reserves for injuries and damages are addressed in Section 8.1.

566. As the Supreme Court of Canada has rendered its decision on ATCO Pipelines' 2011 pension decision, the Commission agrees with ATCO Pipelines that a placeholder is no longer necessary for the 2015 and 2016 disallowed COLA costs. The placeholders for disallowed MTIP/LTIP, donations and sponsorships, and corporate costs are similarly not required. The Commission directs ATCO Pipelines to remove all of these placeholders in its compliance filing.

9 Depreciation

567. In its application, ATCO Pipelines submitted a technical update to its December 31, 2011 depreciation study, which had been submitted by ATCO Pipelines in its 2013-2014 GRA.

568. The technical update determined updated depreciation rates and amortization of reserve differences amounts for the 2015 and 2016 test years based on plant in service balances, as of December 31, 2013 (the balances, of which, were adjusted for pending retirements³⁹¹ to be processed in 2014). The impact of the technical update, based on December 31, 2013 plant in service balances, was an increase in depreciation expense of \$1.39 million.³⁹²

569. ATCO Pipelines stated that a technical update assists in ensuring that depreciation rates and amortization of reserve differences amounts are at an optimal level until the completion of the next full depreciation study. This is achieved by applying the currently approved depreciation parameters to the most recent actual plant in service information to develop the most current and relevant depreciation rates for the test years. The amortization of reserve differences amounts are also recalculated during the course of a technical update.

570. ATCO Pipelines' technical update was prepared by Mr. Earl Robinson of AUS Consultants using the same methodology and depreciation parameters (service life, Iowa curve and net salvage per cents) as approved in Decision 2013-430. The updated depreciation rates and amortization of reserve differences amounts formed the basis for ATCO Pipelines

³⁹¹ Exhibit 0003.00.ATCOPIPE-3577, 8.2 Attachment – Depreciation Study, page 3 stated that pending retirements were related to investment for which the age exceeded the proposed average service life's maximum life as well as normal ongoing retirements or transfer adjustments.

³⁹² Exhibit 3577-X0294, AP-AUC-2015FEB03-104(c), Schedule 6, 3 of 3.

forecast depreciation expense calculations for the test years. Net depreciation expense was forecast in the amount of \$57.65 million in 2015 and \$67.26 million in 2016.³⁹³

571. Year-over-year increases with respect to net depreciation expense are presented in the following table:

Table 38. Year-over-year comparison of net depreciation expense

	2013 actual	2014 estimate	2015 forecast	2016 forecast
	(\$ million)			
Net depreciation expense using approved depreciation parameters (2015 and 2016 reflect results of the technical update)	47.081	51.297	57.650	67.261
Increase/(decrease) in net depreciation expense year-over-year		4.216	6.353	9.611

Source: Exhibit 3577-X0182, Financial schedules update, Table 4.4-1.

572. ATCO Pipelines attributed the year-over-year increases primarily to increasing pipeline system capital investments.

573. In addition to seeking approval of the depreciation rates and amortization of reserve differences amounts arising from its technical update, ATCO Pipelines requested that the Commission approve the componentization of wells inspection into a new asset subaccount (Account 45301 – wells inspection) in 2015 with an amortization period of 10 years. ATCO Pipelines clarified that despite Decision 2013-064,³⁹⁴ in paragraph 101, wherein the Commission had approved the proposed capitalization accounting treatment of wells inspections, ATCO Pipelines had inadvertently not requested the further componentization by subaccount, of wells inspection at that time.³⁹⁵ The proposed amortization period of 10 years was based on achieving consistency with “the Canadian Standards Association for Dry Gas Storage operators, subsection 10.2.5.2-Dry gas storage caverns [which stated that] at ‘every ten years, operators of dry storage caverns shall (a) carry out an integrity inspection workover in accordance with Clause 10.2.5.1; or (b) conduct an integrity inspection workover on the storage caverns and wells...’”³⁹⁶

574. ATCO Pipelines also requested approval of a new subaccount for field laptop assets (Account 48911 – field laptops) with an amortization period of four years. The amortization period was based on consultation with Mr. Robinson who examined the industry standards along with considerations of the laptop units. A further consideration was that these assets would be replaced at intervals of four years to address technical advancements and physical condition.

575. The two proposed subaccounts would be included in ATCO Pipelines’ next full depreciation study, which was anticipated to be filed at the time of its next GRA application.^{397 398}

³⁹³ Exhibit 3577-X0182, Financial schedules update, Table 4.4-1.

³⁹⁴ Decision 2013-064: ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., 2012 Final Revenue Requirement Application, Proceeding 2041, Application 1608689-1, February 28, 2013.

³⁹⁵ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 4.4, page 4 of 6.

³⁹⁶ Exhibit 0003.00.ATCOPIPE-3577, 8.2 Attachment – Depreciation Study, page 3.

³⁹⁷ Exhibit 3577-X0179, ATCO Pipelines updated application, Section 4.4, page 5 of 6.

³⁹⁸ Transcript, Volume 3, pages 635-636.

576. The impact of ATCO Pipelines subaccount proposals, in combination with updated depreciation rates and amortization of reserve differences amounts resulting from the technical update, are presented in the following table:

Table 39. Impact of ATCO Pipelines technical update on net depreciation expense

	2015 forecast	2016 forecast
	(\$ million)	
Net depreciation expense using proposed rates (output from technical update)	57.650	67.261
Net depreciation expense using approved rates	56.560	66.135
Impact of technical update on net depreciation expense: increase/(decrease)	1.090	1.126

Source: Exhibit 3577-X0182, Financial schedules update, Table 4.4-2.

577. ATCO Pipelines stated that it had also addressed any errors or discrepancies raised in information requests in its June 22, 2015, application update.

578. ATCO Pipelines concluded it had provided the necessary support for its depreciation technical update and no other parties provided evidence against ATCO Pipelines' depreciation-related requests. Accordingly, ATCO Pipelines submitted that the Commission should approve its proposed updated straight line, equal life group depreciation rates, amortization rates, amortization of reserve differences amounts, the componentization of well inspection costs and field laptops (with corresponding amortization periods of ten and four years respectively).³⁹⁹

Commission findings

579. The Commission agrees with ATCO Pipelines that parties intervening in this proceeding did not file evidence or identify any issues with respect to the depreciation expense determined by ATCO Pipelines for the 2015 and 2016 test years. The Commission accepts the evidence and submissions of ATCO Pipelines with respect to depreciation expense in the test period because the basis for its calculation is consistent with the depreciation parameters approved in the prior depreciation study and the results of the technical update. The creation of the two subaccounts is reasonable given ATCO Pipelines' explanations of why Account 45301 – wells inspection is required, and because of the recommended change in the amortization period of laptops a new subaccount is needed, Account 48911 – field laptops.

580. The Commission also agrees that ATCO Pipelines' updated forecast depreciation rates and amortization of reserve differences amounts for 2015 and 2016 are reasonable and supported by the evidence on the record, and are therefore approved, as filed. The Commission, however, directs ATCO Pipelines, in the compliance filing to this decision, to update the depreciation expense forecasts to reflect the applicable directions included in this decision, most notably the directions with respect to the capital projects.

10 Compliance with Commission directions

581. The Commission has reviewed Section 6.1 of the application as well as the attachments to Section 6.1, and is satisfied with ATCO Pipelines' explanation of the status of compliance

³⁹⁹ Exhibit 3577-X0328, ATCO Pipelines argument, paragraphs 80, 190 and 192.

with previous directions of the Commission, the identification of any related proceeding wherein ATCO Pipelines complied with past directions and its progress with complying with any ongoing directions.

11 Order

582. It is hereby ordered that:

- (1) ATCO Pipelines is directed to file a compliance filing in accordance with the findings and directions in this decision, no later than April 14, 2016.

Dated on February 29, 2016.

Alberta Utilities Commission

(original signed by)

Neil Jamieson
Panel Chair

(original signed by)

Bill Lyttle
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Pipelines Bennett Jones LLP
Encana Corporation
Cenovus Energy Inc.
Consumers' Coalition of Alberta (CCA)
NOVA Gas Transmission Ltd. (NGTL)
The City of Calgary McLennan Ross Barristers & Solicitors
The Office of the Utilities Consumer Advocate (UCA) Bull, Housser & Tupper LLP
Canadian Association of Petroleum Producers (CAPP)
Nexen Energy ULC

Alberta Utilities Commission
Commission panel
N. Jamieson, Panel Chair
B. Lyttle, Commission Member
Commission staff
A. Sabo (Commission counsel)
M. McJannet
R. Armstrong, P.Eng.
M. Kopp-van Egteren
S. Karim
B. Yanchula
L. Mullen

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
ATCO Pipelines R. Gretener T. Myers	L. Radke J. Sharpe B. Hahn G. Schmidt B. Shkrobot S. Mah K. Yung (Mercer Canada Limited)
Canadian Association of Petroleum Producers (CPP) N. Schultz	
Consumers' Coalition of Alberta (CCA) J. Wachowich	
The City of Calgary D. Evanchuk	H. Johnson S. Stephens
The Office of the Utilities Consumer Advocate (UCA) M. Keen A. Stainer	R. Bell

Alberta Utilities Commission Commission panel N. Jamieson, Panel Chair B. Lyttle, Commission Member Commission staff A. Sabo (Commission counsel) M. McJannet R. Armstrong, P.Eng. M. Kopp-van Egteren B. Yanchula	

Appendix 3 – Summary of Commission directions

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

1. The Commission reviewed the variances between ATCO Pipelines' 2014 actual and approved rate base and is satisfied with the explanations provided by ATCO Pipelines through information responses to IRs. However, the Commission has compared the original 2014 forecast opening property, plant and equipment filed on December 17, 2015, with the corresponding table filed in its June 22, 2015 application update, and it does not appear that the financial schedules align with the adjustment to opening rate base noted above, in Table 4. ATCO Pipelines is therefore directed, in its compliance filing, to review its June 22, 2015 opening rate base adjustments, and all other adjustments it provided in its application update at Exhibit 3577-X0184, and provide the Commission with confirmation that ATCO Pipelines' financial schedules are consistent with revised information reflected in the June 22, 2015 update. ATCO Pipelines is directed to reflect any revisions required to its financial schedules in the compliance filing to this decision. Paragraph 48
2. ATCO Pipelines is directed to reduce its forecast by 10 per cent for replacement and improvement capital expenditures. The Commission considers a 10 per cent reduction is reasonable given the historical information provided by ATCO Pipelines for capital expenditures in this category, and given the forecast work and capital expenditures that are likely to result from capital projects to be undertaken in 2015 and 2016. Paragraph 125
3. The Commission agrees with the CCA that the lack of transparency with respect to the hydraulic analysis, technical justification and the confidential nature of NGTL's approval for UPR projects is a serious concern. In spite of information that may be confidential, in future general rate applications, the Commission directs ATCO Pipelines to provide more detailed information to support the hydraulic analysis, technical justification and financial justification of its pipeline projects, including NGTL's rationale for its approvals. The Commission considers that this approach is reasonable because it allows for efficient processing of the current application but acknowledges that further information is required on a go-forward basis. It will also allow ATCO Pipelines the opportunity to consult with NGTL on what information can be disclosed on a public basis, and if there are concerns with confidentiality, ATCO Pipelines can apply to the Commission for confidential treatment of information that may be required to support its revenue requirement with respect to UPR projects or other pipeline projects that may require information from NGTL. Paragraph 148
4. It appears to the Commission that the timing of the tendering may have much to do with the bid prices and re-tendering has provided some price relief, in part due to the economic downturn. ATCO Pipelines reduced its forecast expenditures during the test years by five per cent, and these forecasts are approved as filed. However, given the current economic climate, ATCO Pipelines is directed to provide an update on its efforts to reduce UPR capital costs in the compliance filing, and to provide the actual costs of these projects for the 2015 test year. Paragraph 150

5. The Commission notes that the Inland Looping project has been revised into two discrete projects, the Inland Loop project consisting of 18 km of pipeline and the Pembina Loop project. Given ATCO Pipelines' explanation of the change in scope of the Inland Loop project, the Commission approves the inclusion of the Inland Looping project in the NGTL directed growth capital deferral account. The Commission has reviewed the evidence with respect to the need for the project and the related forecast capital costs (or capital expenditures) and is satisfied that they are reasonable. Therefore, the Commission approves the need for the project and related forecast. As a result of the change in scope of this project, ATCO Pipelines is directed in its compliance filing to reflect the updated forecast of \$40 million in the NGTL deferral account and confirm that the Inland Looping and Pembina Loop project pipeline are still expected to be in service by November 2016. Paragraph 164
6. For these reasons, the Commission reduces the forecast estimate by the average cost to upgrade eight stations, which results in a disallowance of \$180,444 (i.e. $\$1,015,000 / 45 \times 8 = \$180,444$) split equally between both test years. The Commission directs ATCO Pipelines to reflect this reduction to its capital expenditures for the H2S warning lights at its stations, in the compliance filing to this decision. Paragraph 206
7. Therefore, ATCO Pipelines is directed to file an update to the Edmonton office expansion business case in the compliance filing to this decision, and the update of FTE requirements. ATCO Pipelines is directed to maintain the capital estimate of \$8.5 million for the office expansion as a placeholder. Paragraph 216
8. Accordingly, the costs for the above IT projects are denied. ATCO Pipelines is directed to remove the capital expenditures totaling \$4.95 million from the test years. Paragraph 241
9. The Commission considers that the use of the mid-year convention is an accepted practice for treating capital additions and considers any inclusion of capital additions in NWC would require a more comprehensive review of the applicability of the mid-year convention for capital related items. Therefore, ATCO Pipelines is directed to further explain, in its next GRA, why its capital additions lag the mid-year convention and whether on a go-forward basis it is, or is not, appropriate to include capital additions or other capital related items in NWC. Subject to any other findings included in this decision, the NWC forecasts for the test years are approved, as filed. Paragraph 272
10. As discussed in Section 6.3.1 below, the expenses for the gap analysis for implementation of ISO 55001 were denied. ATCO Pipelines is therefore directed to remove any O&M labour expense associated with this project in the compliance filing. All other O&M labour expenses will be discussed in the sections below. Paragraph 291
11. Accordingly, the Commission approves a 3.0 per cent out-of-scope salary escalation factor for both 2015 and 2016. The Commission considers that the 3.0 per cent should be inclusive of all salary increases and promotional increases. The Commission directs ATCO Pipelines to reflect the 3.0 per cent out-of-scope escalation factor in its compliance filing to this decision. Paragraph 325
12. Given the Commission's November 27, 2015 and December 10, 2015 rulings on the matter of placeholder treatment for FTEs and their related costs, the Commission continues to direct ATCO Pipelines to clearly identify the impact of announced employee reductions on forecast FTEs and revenue requirement for the test years. The FTE costs will continue to be treated as a placeholder until the impact of employee reductions is

- assessed in the compliance filing to this decision. The Commission considers that ATCO Pipelines can take into account the arguments and reply arguments of interveners in preparing its compliance filing to this decision with respect to FTEs. Paragraph 366
13. The Commission, in factoring the current market conditions that are expected to result in lower supplies costs and the counterbalancing current exchange rate, finds that the recommendation of 1.7 per cent for supplies inflation for 2015 and 2016 is reasonable given the current market conditions and the higher exchange rate affecting supply costs. As a result, the Commission directs ATCO Pipelines to use a supplies inflation factor of 1.7 per cent. Paragraph 395
 14. Accordingly, the Commission directs ATCO Pipelines to remove the \$1.6 million related to the ISO 55001 from revenue requirement during the test years. ATCO Pipelines may choose to provide a proposal for a gap analysis related to ISO 55001 certification in a future GRA. Paragraph 410
 15. For other O&M labour and supplies costs which include estimates for specific work related to the asset management system projects, such as the costs included in contract services O&M supplies cost category, ATCO Pipelines is directed to recalculate the O&M labour and supplies costs to reflect the denial of the ISO 55001 project costs for the test period. Paragraph 411
 16. The Commission has reviewed the forecast A&G costs and finds that the forecasts are reasonable given the information provided in tables 25 and 26 above and are approved, subject to the findings above regarding supplies inflation. Consistent with the direction on supplies inflation in Section 6.3, the Commission directs ATCO Pipelines to revise its forecast A&G costs to use the approved 1.7 per cent for supplies inflation, where applicable and to provide a revised Table 25 in its compliance filing to this decision. Paragraph 422
 17. Additionally, the Commission has denied ATCO Pipelines' forecast costs for the asset management IT capital projects (Hyperion, Maximo Phase 2 and the GIS, PIMS and MMS enhancements), which may have a corresponding impact on IT volumes. The Commission understands that forecast baseline volumes are specified in the Wipro MSA, but for the purposes of this application, directs ATCO Pipelines to submit revised forecast IT volumes in the compliance filing, which take into account the denial of the asset management IT capital projects in this decision and to account for changes in ATCO Pipelines' forecast staffing levels as a result of the recent announcement of employee reductions by the ATCO Group. Paragraph 451
 18. The Commission further directs ATCO Pipelines to file all of its forecast IT volume data for the test period and actual volumes from the previous test period, in all future GRAs. Paragraph 452
 19. In a letter dated October 28, 2015, the Commission determined that the issue of licence fees would be heard in a common licence fee proceeding with ATCO Electric in order to allow the Commission to address the licence fee issues related to both the ATCO Electric GTA and the ATCO Pipelines GRA. This matter is currently being heard in Proceeding 21029, which will address ATCO Electric Transmission's 2015-2017 and ATCO Pipelines 2015-2016 licence fees. The Commission directed ATCO Electric and ATCO Pipelines to file a joint licence fee application with the Commission and therefore the Commission makes no determination on the licence fee issue in this application. The Commission directs ATCO Pipelines to include a zero dollar placeholder as directed in

the Commission's October 9, 2015 ruling in its compliance filing to this proceeding.

..... Paragraph 455

20. For these reasons, the Commission directs ATCO Pipelines to incorporate the 2016 debt rate 4.29 per cent forecast shown in the following table in its compliance filing application: Paragraph 489

Table 31. 2016 debt rate forecast

Description		2016
	(%)	
Consensus forecast, 10-year (Exhibit 3577-X0297)		
December 2015	1.7	
December 2016	2.2	
2016 mid-year	1.95	1.95
10-30 year bond differential (Exhibit 3677-X0064, AP-AUC-75)		0.54
Credit spread (Transcript, Volume 2, page 419, lines 10-19)		1.80
2016 forecast debt rate		4.29

21. In the context of this application, the Commission recognizes that its predecessor, the Alberta Energy and Utilities Board, directed ATCO Pipelines to estimate the annual charge to the reserve fund based on one incident every five years. However, given the submissions of interveners, the Commission is cognizant that the environment in which that direction was made has changed and may not be the optimum methodology going-forward. However, consistent with past findings that a five-year average is optimal for estimates when specific costs are not available, the Commission finds it reasonable for ATCO Pipelines to use a five-year average to estimate unspecified incidents in the RID. In its next GRA, ATCO Pipelines is directed to provide an analysis of whether the five-year average remains the optimal methodology for the RID. Paragraph 521
22. Accordingly, the Commission considers that the Bittern Lake claim with the Surface Rights Board has already been approved for inclusion in the RID and therefore will not direct ATCO Pipelines to remove the associated legal fees from the RID. For future costs that may result from Surface Rights Board claims, or other regulatory proceedings that may result in legal or other costs, ATCO Pipelines is directed to identify and explain whether these costs should appropriately be included in the RID, or whether the costs are more appropriately included in a different, or separate, deferral account. ... Paragraph 524
23. The Commission considers that there is sufficient explanation on the record regarding the benefits of combining the AUC operating fees deferral account and hearing costs reserve account. Further, the proposal to combine the accounts would appear to reduce the number of deferral accounts that ATCO Pipelines is required to manage, and therefore, would create regulatory efficiency. The Commission finds that combining the two accounts is not expected to result in harm to the utility or to the public. The combining of the two deferral accounts into a single deferral account is approved. To ensure transparency and to allow for the continued identification of AUC operating costs within the account, ATCO Pipelines is directed to record separately, AUC operating costs and hearing costs, within the combined deferral account. Paragraph 534
24. With regard to CAPP's recommendation that the hearing costs be settled simultaneously with the settling of AUC operating fees when combining the accounts, the Commission finds that this would assist in the tracking of costs included in the combined reserve

- account going-forward. The Commission therefore directs ATCO Pipelines to include the settlement of the AUC operating fees and hearing costs in its compliance filing, to recalculate the proposed settlement amount and to advise if there is any change to the proposed one-time adjustment for the settlement balance from the amount proposed in the application. Paragraph 535
25. The Commission considers that given the ongoing generic proceeding to address tax methodologies for regulated utilities, it is premature to approve ATCO Pipelines' proposal for a deduction of deferrals for tax purposes deferral account. Therefore, the Commission directs ATCO Pipelines to continue its practice of collecting or refunding deferred taxes on deferral balances for the test period. Paragraph 543
26. As the Supreme Court of Canada has rendered its decision on ATCO Pipelines' 2011 pension decision, the Commission agrees with ATCO Pipelines that a placeholder is no longer necessary for the 2015 and 2016 disallowed COLA costs. The placeholders for disallowed MTIP/LTIP, donations and sponsorships, and corporate costs are similarly not required. The Commission directs ATCO Pipelines to remove all of these placeholders in its compliance filing. Paragraph 566
27. The Commission also agrees that ATCO Pipelines' updated forecast depreciation rates and amortization of reserve differences amounts for 2015 and 2016 are reasonable and supported by the evidence on the record, and are therefore approved, as filed. The Commission, however, directs ATCO Pipelines, in the compliance filing to this decision, to update the depreciation expense forecasts to reflect the applicable directions included in this decision, most notably the directions with respect to the capital projects. Paragraph 580
28. (1) ATCO Pipelines is directed to file a compliance filing in accordance with the findings and directions in this decision, no later than April 14, 2016. Paragraph 582



EPCOR Distribution & Transmission Inc.

2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast

February 7, 2016

Alberta Utilities Commission

Decision 20407-D01-2016

EPCOR Distribution & Transmission Inc.

2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast
Proceeding 20407

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1 Introduction

1. On May 4, 2015, EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) filed an application with the Alberta Utilities Commission requesting approval of its 2014 capital tracker true-up and 2016-2017 capital tracker forecast under performance-based regulation (PBR). EPCOR further requested that the revenue requirement associated with the applied-for capital trackers be included in the applicable year, in the K factor component of the PBR rate formula approved in Decision 2012-237.¹

2. On May 5, 2015, the Commission issued a notice of application that required interested parties to submit a statement of intent to participate (SIP) by May 14, 2015. In their SIPs, parties were to provide a description of their interest in the proceeding, an explanation of their position and process submissions. The Commission received SIPs from the Consumer's Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA).

3. After reviewing the application and the SIPs, the Commission determined that the application would be considered by way of a *full process* proceeding, as described in Bulletin 2015-09,² and established a schedule for the proceeding as set out in the table below.

Process step	Deadline dates
Information requests (IRs) to EPCOR	June 12, 2015
IR responses from EPCOR	June 26, 2015
Intervener evidence	July 17, 2015
IRs to interveners	July 31, 2015
IR responses from interveners	August 14, 2015
Rebuttal evidence	August 24, 2015
Oral hearing	September 3 to September 11, 2015

¹ Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

² Bulletin 2015-09, Performance standards for processing rate-related applications, March 26, 2015.

4. At the oral hearing, the Commission determined the following additional process steps:³

Process step	Deadlines dates
IRs on outstanding undertakings	September 16, 2015
IR responses on outstanding undertakings	September 18, 2015
Argument	October 16, 2015
Reply argument	November 6, 2015

5. In its letter dated October 15, 2015, the Commission revised the date for filing argument to October 19, 2015, as requested by the CCA. There was no change to the date for filing reply argument.⁴

6. EPCOR and the UCA filed their respective reply arguments by the indicated deadline of November 6, 2015. The CCA filed its reply argument on November 9, 2015. The Commission accepted the late filing of the CCA reply argument. Accordingly, the Commission considers the record for this proceeding to have closed on November 9, 2015.

7. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, as well as relevant portions of the records considered by the Commission in proceedings leading to Decision 3100-D01-2015,⁵ and related compliance filing Decision 20210-D01-2015.⁶ Accordingly, references in this decision to specific parts of the records 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 records with respect to a particular matter.

2 Background

2.1 Overview of the capital tracker approach under PBR

8. On September 12, 2012, the Commission issued Decision 2012-237, approving PBR plans for the distribution utility services of certain Alberta electric and gas companies (collectively the distribution utilities), including EPCOR. The PBR plans were approved for a five-year term commencing January 1, 2013. PBR replaces traditional cost of service regulation as the annual rate-setting mechanism for distribution utility rates.

³ Transcript, Volume 6, page 1025, lines 17-23.

⁴ Exhibit 20407-X0229, AUC letter - Procedural matters, October 15, 2015.

⁵ Decision 3100-D01-2015: EPCOR Distribution & Transmission Inc., 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast, Proceedings 3216 and 3100, Applications 1610565-1 and 1610362-1, January 25, 2015.

⁶ Decision 20210-D01-2015: EPCOR Distribution & Transmission Inc., 2013-2015 Capital Trackers Compliance Filing, Proceeding 20210, May 29, 2015.

9. As set out in Decision 2012-237, the PBR framework provides a formula mechanism for the annual adjustment of rates for those companies under an approved PBR plan. In general, the rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation (I), which is relevant to the prices of inputs the companies use, less an offset (X) to reflect the productivity improvements the company can be expected to achieve during the PBR plan period. As a result, with the exception of specifically approved adjustments, a utility's revenues are no longer linked to its costs. Companies subject to a PBR regime must manage their businesses and service obligations with the revenues derived under the PBR indexing mechanism and adjustments provided for in the formula. The PBR framework is intended to provide incentives for productivity increases and cost savings similar to those operating in competitive markets.

10. A company may apply for approval of certain rate adjustments to enable the recovery of specific costs where it can be demonstrated that the costs cannot be recovered under the I-X mechanism and where certain other criteria have been satisfied. These possible adjustments include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (a Y factor), and an adjustment to account for the effect of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan (a Z factor). In addition, the Commission determined that a rate adjustment mechanism to fund certain capital-related costs may be required under the approved PBR plans.⁷ This supplemental funding mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate setting formula.

11. At paragraph 592 of Decision 2012-237, the Commission set out three criteria that any capital project or program would have to satisfy in order to receive capital tracker treatment:

- (1) The project must be outside of the normal course of the company's ongoing operations.
- (2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
- (3) The project must have a material effect on the company's finances.

12. Further, at paragraph 593 of Decision 2012-237, the Commission indicated that the party recommending the capital tracker must demonstrate that all of the criteria have been satisfied in order for a capital project or program to receive consideration as a capital tracker.

13. The implementation and application of the above capital tracker criteria were considered in the 2013 capital trackers proceeding, leading to Decision 2013-435.⁸ The Commission indicated that the implementation methodology established in that decision would be used not only to evaluate the capital tracker projects or programs proposed by the parties for 2013, but also for subsequent capital tracker applications throughout the PBR term.⁹

⁷ Decision 2012-237, paragraph 586.

⁸ Decision 2013-435: Distribution Performance-Based Regulation 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

⁹ Decision 2013-435, paragraph 120.

14. With respect to the first capital tracker criterion, the Commission concluded that, in general, in order for a capital project or program to be considered outside of the normal course of the company's ongoing operations, the utility would need to demonstrate that the revenue provided under the I-X mechanism in respect of that project or program would be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program. Accordingly, the Commission found that the concept of normal course is mainly a financial and accounting consideration, rather than strictly an engineering consideration. The Commission referred to this comparison of revenues as the "accounting test" component of Criterion 1. In addition, the Commission indicated the utility must demonstrate that a project or program proposed for capital tracker treatment is (i) required to provide utility service at adequate levels (also referred to as a need assessment) and, if so, (ii) the scope, level and timing of the project are prudent, and the forecast or actual costs of the project or program are reasonable. The Commission referred to this as the "project assessment" component of Criterion 1. Both the accounting test component and the project assessment component must be satisfied in order for a capital project or program to satisfy the requirements of Criterion 1.¹⁰

15. Regarding the accounting test component of Criterion 1, the Commission determined that this test should be based on the project net cost approach adopted in Decision 2013-435. Under this methodology, the revenue generated under the I-X mechanism for each capital project (or capital program or project category) is compared to the forecast revenue requirement associated with that capital project (or capital program or project category) in a PBR year. No consideration of operating and maintenance (O&M) costs or savings and potential productivity offsets above those implied by the approved X factor is required for the accounting test. The Commission provided further clarification on the weighted average cost of capital (WACC) rate assumptions of the accounting test in Decision 3434-D01-2015.¹¹

16. For purposes of the project assessment, the Commission determined that each project or program proposed for capital tracker treatment must generally be supported by a business case and an engineering study. However, the Commission recognized that in some circumstances, an engineering study may not be required. In Decision 2013-435, the Commission set out certain minimum filing requirements that a project or program proposed for capital tracker treatment should typically address in order to assist the Commission's project assessment.¹² These minimum filing requirements were subsequently refined in Decision 3558-D01-2015.¹³

17. At paragraph 615 of Decision 2012-237, the Commission indicated that a company may choose to undertake a capital investment prior to applying for capital tracker treatment in a subsequent annual capital tracker filing. The Commission further clarified at paragraph 48 of Decision 2013-435:

¹⁰ Decision 2013-435, paragraphs 149-150.

¹¹ Decision 3434-D01-2015: Distribution Performance-Based Regulation Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015.

¹² Decision 2013-435, paragraphs 1091-1092.

¹³ Decision 3558-D01-2015: Distribution Performance-Based Regulation Commission-initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications, Proceeding 3558, Application 1611054-1, April 8, 2015, Appendix 3, pages 25-26.

48. It was acknowledged by the Commission that superior incentives for capital trackers would result if the companies were required to spend money on capital expenditures prior to receiving approval for capital tracker recovery of the expenditures. However, given the lack of experience with the capital tracker mechanism, for the first generation PBR plans, it was determined that the companies will be permitted to apply for capital trackers on a forecast basis. The approved forecast cost of a capital tracker project will be included in rates on an interim basis and will be subject to a true-up to prudently incurred actual expenditures, after the project is completed. The true-up process will test the prudence of the actual capital expenditures and imprudent expenditures will be subject to disallowance. As a result, the capital tracker mechanism retains some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred. The true-up mechanism with a prudence review also mitigates somewhat the incentive for companies to overstate the initial capital tracker forecasts. Nonetheless, the companies remained free to incur expenditures prior to applying for capital tracker approval. [footnotes removed]

18. With respect to Criterion 2, in Decision 2013-435, the Commission clarified that, in addition to asset replacement projects and projects required by an external party, in principle, a growth-related project will satisfy the requirements of Criterion 2. This is so where it can be demonstrated that the sum of the incremental revenues allocated to the project on some reasonable basis, the revenue provided under the I-X mechanism and any customer contributions to the project, are insufficient to offset the revenue requirement associated with the project in a PBR year.¹⁴ In certain circumstances, Criterion 2 may also permit consideration of certain projects for capital tracker treatment that do not fall into any of the growth-related, asset replacement or external party-related categories.

19. Under Criterion 3, the Commission determined that applying a materiality threshold to that portion of the revenue requirement for a project that is not funded under the I-X mechanism is warranted. The Commission established a two-tier materiality threshold. The first tier of the materiality threshold, a “four basis point threshold,” is to be applied at a project level (grouped in the manner approved by the Commission). The second tier of the materiality threshold, a “40 basis point threshold,” is to be applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.

20. Additionally, the Commission recognized the significance of the grouping of projects proposed for capital tracker treatment when it stated in paragraph 601 of Decision 2012-237:

601. ... The Commission also considers that it would not be suitable to group together several dissimilar projects into a single large project to give the appearance of materiality. However, a number of smaller related items required as part of a larger project might qualify for capital tracker treatment.

21. In Decision 2013-435, the Commission further elaborated that grouping of projects will require close scrutiny, since it will have a direct effect on the results of the accounting test and the project assessment under Criterion 1, as well as the assessment of materiality under Criterion 3. The Commission determined that the reasonableness of the grouping of capital projects is best assessed on a case-by-case basis for each company. The Commission indicated

¹⁴ Decision 2013-435, paragraph 309.

that it will require each company to provide sufficient justification for its proposed grouping of projects for capital tracker treatment.¹⁵

22. Finally, in Section 4.4 of Decision 2013-435, the Commission set out the K factor calculation methodology. Under the approved methodology, the K factor calculations sum the incremental revenue requirement amounts (i.e., additional to the amounts provided under the I-X mechanism) for each project or program approved for capital tracker treatment, as determined using the project net cost approach.

23. As set out in Decision 2012-237, the company will only be permitted to collect the forecast amounts for the capital tracker on an interim basis, and a true-up to the actual amount of the capital tracker will occur after the capital expenditures have been made. The Commission outlined the capital tracker true-up process as follows:

975. ... the March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.¹⁶

24. On true-up, a K factor adjustment will be made based on the actual dollars spent on the projects or programs approved for capital tracker treatment, with the difference between the approved forecast K factor amount and actual K factor amount refunded to, or collected from, customers.

2.2 EPCOR's prior capital tracker-related proceedings

25. Because the 2013 capital tracker proceeding leading to Decision 2013-435 had not yet been completed at the time the Commission established 2013 interim PBR rates in Decision 2013-072,¹⁷ the Commission approved, on an interim basis, a 2013 capital tracker placeholder (K factor) for EPCOR, equal to 60 per cent of the applied-for K factor amount. Accordingly, EPCOR was directed to include in its 2013 PBR rates, a K factor placeholder of \$3.02 million on an interim basis.¹⁸

26. Similar interim K factor placeholders were approved by the Commission for each of 2014, 2015 and 2016. In Decision 2013-462,¹⁹ the Commission approved on an interim basis, a K factor placeholder in the amount of \$6.8 million to be included in EPCOR's 2014 PBR rates.²⁰

¹⁵ Decision 2013-435, paragraphs 403 and 406.

¹⁶ Decision 2012-237, paragraph 975.

¹⁷ Decision 2013-072: 2012 Performance-Based Regulation Compliance Filings, AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc., Proceeding 2130, Application 1608826-1, March 4, 2013.

¹⁸ Decision 2013-072, Table 1, paragraph 41.

¹⁹ Decision 2013-462: EPCOR Distribution & Transmission Inc. 2014 Annual PBR Rate Adjustment Filing, Proceeding 2823, Application 1609912-1, December 20, 2013.

²⁰ Decision 2013-462, paragraph 58.

In Decision 2014-346,²¹ the Commission approved on an interim basis, a 2015 K factor placeholder in the amount of \$18.108 million equal to 90 per cent of the proposed 2015 K factor.²² In Decision 20821-D01-2015,²³ the Commission approved on an interim basis, a 2016 K factor placeholder in the amount of \$24.81 million equal to 90 per cent of the proposed 2016 K factor.²⁴

27. In Decision 2013-435, dealing with the 2013 capital trackers, the Commission approved certain EPCOR projects for capital tracker treatment on a forecast basis, resulting in a 2013 K factor forecast amount of \$4.87 million²⁵ to be recovered from customers on an interim basis, pending future true-up proceedings. In Decision 2014-174,²⁶ the Commission approved EPCOR's application to collect the \$1.85 million difference between the 60 per cent placeholder and the approved K factor forecast amount for 2013.²⁷

28. In Decision 3100-D01-2015, the Commission dealt with EPCOR's 2013 K factor true-up and 2014-2015 K factor forecast applications. In accordance with the Commission's determinations in that decision, EPCOR filed a compliance filing to address the identified issues and Commission directions. The 2013 K factor true-up amount and 2014-2015 K factor forecast amounts were approved in the compliance filing resulting in Decision 20210-D01-2015. As set out in that decision, the Commission approved a 2013 actual K factor of \$4.31 million and the associated 2013 K factor true-up refund amount of \$0.56 million. The Commission also approved the 2014 and 2015 forecast K factors of \$8.83 million and \$17.18 million, respectively, on an interim basis pending future true-up proceedings.²⁸

29. Finally, in Decision 20559-D01-2015,²⁹ the Commission approved EPCOR's application to refund the \$0.56 million difference between the 2013 K factor forecast approved in Decision 2013-435 and the 2013 actual K factor approved in Decision 20210-D01-2015. In addition, in that decision, the Commission approved EPCOR's application to refund the \$0.93 million difference between the 2015 K factor placeholder, approved on an interim basis in Decision 2014-346, and the 2015 K factor forecast approved in Decision 20210-D01-2015. Inclusive of carrying costs, the total combined refund amount for 2013 and 2015 was \$1.54 million.³⁰

30. As also set out in Decision 20559-D01-2015, to avoid an unnecessary collection followed by an expected refund, EPCOR proposed to true-up the difference between the 2014 K factor placeholder and the 2014 actual K factor amount, once the final true-up amount is approved by

²¹ Decision 2014-346: EPCOR Distribution & Transmission Inc., 2015 Annual PBR Rate Adjustment Filing, Proceeding 3403, Application 1610834-1, December 15, 2014.

²² Decision 2014-346, paragraph 44.

²³ Decision 20821-D01-2015: EPCOR Distribution & Transmission Inc. 2016 Annual Performance-Based Regulation Rate Adjustment Filing, Proceeding 20821, December 15, 2015.

²⁴ Decision 20821-D01-2015, paragraph 41.

²⁵ Decision 2013-435, paragraph 989.

²⁶ Decision 2014-174: EPCOR Distribution & Transmission Inc. 2013 K Factor True-up Rider, Proceeding 3026, Application 1610244-1, June 17, 2014.

²⁷ Decision 2014-174, paragraphs 8 and 29.

²⁸ Decision 20210-D01-2015, paragraph 39.

²⁹ Decision 20559-D01-2015: EPCOR Distribution & Transmission Inc. 2013 and 2015 K Factor True-up Rider, Proceeding 20559, September 24, 2015.

³⁰ Decision 20559-D01-2015, paragraphs 10 and 23.

the Commission in the proceeding that is the subject of this decision. The Commission accepted this proposal.³¹

3 Commission process for reviewing 2014 capital tracker true-up and 2016-2017 capital tracker forecast

31. Subject to the modification explained below, the Commission's process for reviewing 2016-2017 forecast capital tracker applications will largely follow the same steps set out in Section 3 of Decision 3100-D01-2015. Specifically, in Decision 3100-D01-2015, the Commission indicated that for capital tracker forecast purposes, projects or programs previously approved for capital tracker treatment, will not undertake a reassessment of need under Criterion 1 in the absence of evidence that the project or program is no longer required.³²

32. In Decision 3100-D01-2015, the Commission approved the need for each project or program that EPCOR proposed for capital tracker treatment, as part of the project assessment component of Criterion 1, on either an actual basis for 2013 or on a forecast basis for 2014 and 2015, with the exception of the Advanced Metering Infrastructure (AMI) project. However, as noted in Section 4 of this decision, some of these projects failed to satisfy the other capital tracker criteria and were denied capital tracker treatment in the compliance filing resulting in Decision 20210-D01-2015.³³

33. While the Commission will be following the process set out in Section 3 of Decision 3100-D01-2015, for those projects where the Commission has previously determined that a capital tracker project is needed under the project assessment component of Criterion 1, the Commission will not revisit this determination in respect of 2016 and 2017 forecast projects and programs, unless there is evidence on the record of this proceeding demonstrating that a project or program is not required in 2016 or 2017. However, the second part of the project assessment component of Criterion 1 must still be considered so that the Commission can be satisfied that the scope, level, timing and costs of each project or program are reasonable on a forecast basis and prudent on an actual basis. This approach is consistent with the approach taken by the Commission in dealing with the 2013-2015 capital tracker applications from ATCO Electric Ltd., ATCO Gas and Pipelines Ltd. (ATCO Gas), and FortisAlberta Inc.³⁴

34. Further, as set out in sections 6.2.6 and 6.2.8, for any completed capital tracker project where the Commission has previously approved the actual costs of the project and there are no forecast capital additions to be incurred, there is no need for the Commission, in subsequent capital tracker applications seeking to include the completed project in the K factor calculation, to re-evaluate either the need for the completed project, or the prudence of the scope, level and timing of the completed project and associated costs as part of project assessment under Criterion 1. There is similarly no need to repeat the assessment under Criterion 2. However, the accounting test component of Criterion 1, as well as materiality assessments under capital tracker Criterion 3, are still required. The Commission will continue to undertake a project assessment

³¹ Decision 20559-D01-2015, paragraph 14.

³² Decision 3100-D01-2015, paragraphs 25 and 28.

³³ See Tables 2, 3 and 4 of the compliance filing Decision 20210-D01-2015.

³⁴ See, for example Section 3 of Decision 3220-D01-2015: FortisAlberta Inc. 2013-2015 PBR Capital Tracker Application, Proceeding 3220, Application 1610570-1, March 5, 2015.

for any capital tracker project, for which the actual costs were not previously approved by the Commission upon completion.

35. Consistent with the determinations at paragraph 975 of Decision 2012-237 referenced in Section 2, the Commission considers that for the purposes of the true-up of the 2014 capital tracker projects or programs for which the Commission confirmed the need as part of its project assessment in Decision 3100-D01-2015, if there is no evidence on the record of this proceeding demonstrating that a project or program was not required in 2014, then there is no need to again demonstrate that a project or program was needed in order to provide utility service at adequate levels in 2014. However, the second part of the project assessment under Criterion 1 is still required so that the Commission can be satisfied that the scope, level and timing of each project or program was prudent, and the actual costs of the project or program were prudently incurred.

36. The Commission also considers that for the purposes of the true-up of the 2014 capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in Decision 3100-D01-2015, there is also no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program has changed. However, the Commission will still undertake an assessment of the 2014 capital tracker projects and programs with respect to Criterion 3.

37. With respect to forecast capital projects or programs for 2016 and 2017 for which the company is seeking capital tracker treatment, the Commission will generally undertake assessments with respect to all three criteria for capital tracker treatment. However, in those instances where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature (e.g., relocations) for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. However, the second part of the project assessment component of Criterion 1 must still be demonstrated so that the Commission can be satisfied that the scope, level and timing of each project or program is prudent, and that the forecast costs of the project or program are reasonable.

38. With respect to capital tracker projects and programs that have not been previously considered by the Commission and are requested on a forecast basis for 2016 or 2017, EPCOR calculated the K factor revenue requirement calculations for these projects and programs by incorporating the 2013-2014 actual and 2015 forecast capital additions for these projects or programs. In the absence of any evidence that the prior capital additions for the project were not reasonable, given the incentives under the I-X mechanism, the Commission will accept these prior year capital additions for purposes of calculating the second component of the accounting test. In making this determination, the Commission recognizes that the company was motivated to minimize costs with respect to capital projects funded pursuant to the revenues received under the I-X mechanism and that the company provided variance explanations in the business case for the actual expenditures over the most recent five-year period. These pre-capital tracker additions to rate base, however, will be included in the prudence review at the time of rebasing for purposes of establishing the going-in rates for the next generation PBR plan or in a GTA.

39. Similarly, for capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in prior capital tracker decisions, there is no need to undertake a reassessment of the project or program against the

Criterion 2 requirements unless the driver for the project or program has changed. However, the Commission will undertake assessments with respect to the materiality Criterion 3.

40. Section 4 of this decision provides an overview of the projects or programs for which EPCOR is seeking capital tracker treatment in 2014 on an actual basis and in 2016-2017 on a forecast basis. The evaluation of EPCOR's proposed capital project groupings is set out in Section 5. The assessment of EPCOR's projects or programs proposed for capital tracker treatment under Criterion 1 is set out in sections 6 and 7 dealing with the project assessment and the accounting test, respectively. The Commission's assessment under Criterion 2 is undertaken in Section 8 and the assessment under Criterion 3 is set out in Section 9. Section 10 deals with other matters raised in the proceeding. Finally, Section 11 deals with the K factor calculation methodology and the K factor true-up for 2014, as well as K factor forecasts for 2016 and 2017.

4 Summary of projects included in the 2014 capital tracker true-up and the 2016-2017 capital tracker forecast application

41. EPCOR's application was filed as Exhibit 20407-X0130. The schedules setting out EPCOR's capital tracker model for the years 2014 (on an actual basis), 2016 and 2017 (on a forecast basis) were filed as exhibits 20407-X0134, 20407-X0135 and 20407-X0136, respectively.

42. On August 24, 2015, EPCOR submitted a letter along with revised application documents correcting errors discovered during the IR process that relate to the treatment of vehicle depreciation and the application of the half-year rule in EPCOR's capital tracker model that affected most of the proposed capital tracker projects. As well, EPCOR identified an additional error with respect to the treatment of capital costs relating to the asset usage fees (AUFs) paid by EPCOR's transmission function to EPCOR's distribution function for two new capital tracker projects; the Work Centre Redevelopment project and the Outage Management System (OMS) and Distribution Management System (DMS) project. The revised documents were entered into this proceeding as the following exhibits, in accordance with Rule 001: *Rules of Practice*³⁵ requirements:

- Exhibit 20407-X0130.01, EPCOR's cover letter identifying the revisions
- Exhibit 20407-X0130.02, a revised application
- Exhibit 20407-X0134.02, a revised 2014 capital tracker true-up model, Schedule 2
- Exhibit 20407-X0135.02, a revised 2016 capital tracker forecast model, Schedule 3
- Exhibit 20407-X0136.02, a revised 2017 capital tracker forecast model, Schedule 4

43. For continuity purposes, EPCOR also provided revised accounting test schedules for the years 2013 and 2015 in exhibits 20407-X0148 and 20407-X0150, respectively. Throughout this decision, the Commission will refer to these updated documents. Further, prior to the start of the oral hearing, EPCOR identified a number of corrections to its filed documents, including an error in its 2014 true-up capital tracker model.³⁶

³⁵ Rule 001, Section 15.3.

³⁶ Exhibit 20407-X0192, EPCOR's corrections to its filed material.

44. As part of the 2014 capital tracker true-up, EPCOR applied for the true-up of 14 projects or programs approved by the Commission for capital tracker treatment on a forecast basis in Decision 3100-D01-2015, with subsequent updates in the compliance filing Decision 20210-D01-2015.

45. As discussed earlier in Section 2.1, in Decision 2012-237³⁷ and in Decision 2013-435,³⁸ the Commission indicated that a company may choose to undertake a capital investment prior to applying for capital tracker treatment. In other words, capital tracker treatment may be granted on the basis of actual capital expenditures, without prior approval of capital forecasts for a project. In Decision 3100-D01-2015, the Commission approved the need for the Replacement of Faulted Distribution Paper Insulated Lead Covered (PILC) Cables project, but it was not approved for capital tracker treatment for 2014 in the compliance filing Decision 20210-D01-2015 because it failed to satisfy other capital tracker criteria.³⁹ However, this project was afforded capital tracker treatment on a forecast basis for 2015.⁴⁰ EPCOR completed the 2014 scheduled work for this project and has now applied to have the Replacement of Faulted Distribution PILC Cables project reconsidered for 2014 capital tracker treatment on an actual costs basis. Given the prior approval of the need for the project, EPCOR did not include in this application new business cases and engineering studies that were not already provided in the 2014-2015 capital tracker forecast application, for the purpose of the 2014 true-up.⁴¹

46. The projects and programs included in the 2014 capital tracker true-up and the resulting variance from approved forecast, resulting in a K factor true-up for 2014, are set out in the table below.

³⁷ Decision 2012-237, paragraphs 614-615.

³⁸ Decision 2013-435, paragraph 48.

³⁹ Decision 20210-D01-2015, Table 3.

⁴⁰ Decision 20210-D01-2015, Table 4.

⁴¹ Exhibit 20407-X0130, application, paragraph 204.

Table 1. Applied-for 2014 K factor true-up adjustments (\$ million)

No.	Project name	2014 decision K factor ⁴²	2014 actual K factor ⁴³	Variance
Applied-for projects or programs previously approved for capital tracker treatment				
1	Third-Party Driven Relocations	1.58	0.76	(0.82)
2	Life Cycle Replacement and Extension of Underground Distribution Cable	0.82	0.52	(0.29)
3	New 15-kilovolt (kV) and 25-kV Circuit Additions	0.20	0.14	(0.06)
4	New Underground Cable and Aerial Line Reconfigurations and Extensions to Meet Customer Growth	0.73	0.43	(0.29)
5	Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement	0.37	0.25	(0.11)
6	Capitalized Underground System Damage	0.42	0.31	(0.11)
7	New Underground and Aerial Service Connections for Commercial, Industrial, Multi-family and Misc. Customers	0.86	0.70	(0.16)
8	Underground Residential Distribution (URD) Servicing – Rebates, Acceptance Inspections & Terminations	2.35	2.05	(0.30)
9	Poundmaker Feeders	0.56	0.52	(0.04)
10	Capitalized Aerial System Damage	0.11	0.08	(0.03)
11	Underground Industrial Distribution (UID) Servicing – Rebates, Acceptance Inspections & Terminations	0.18	0.15	(0.03)
12	Neighbourhood Renewal Program	0.13	0.12	(0.01)
13	Customer Revenue Metering – Growth & Life Cycle Replacements	0.52	0.50	(0.02)
14	Replacement of Faulted Distribution PILC Cables [Note 1]	--	0.12	0.12
	2014 K factor total	8.83	6.62 [Note 2]	(2.21) [Note 2]

Note 1: In Decision 3100-D01-2015, the Commission approved the need and forecast expenditures as part of the project assessment under Criterion 1 for the Replacement of Faulted Distribution PILC Cables project for 2014 and 2015. However, this project was not afforded capital tracker treatment in 2014 because it did not meet the requirements of other capital tracker criteria on a forecast basis, as set out in the compliance filing Decision 20210-D01-2015, Table 3. This project was approved for capital tracker treatment in 2015, on a forecast basis, as set out in Table 4 of Decision 20210-D01-2015.

Note 2: The 2014 actual K factor amounts associated with individual projects and resulting variances to the approved forecast do not sum up to the total number due to the subsequent corrections identified by EPCOR.⁴⁴

47. As part of the 2016-2017 capital tracker forecast, EPCOR applied for capital tracker treatment for 27 capital projects or programs in either or both of the years 2016 and 2017. Of these, 20 projects or programs were previously approved for capital tracker treatment in either Decision 2013-435 or Decision 3100-D01-2015. The remaining seven projects or programs have not been previously approved for capital tracker treatment.

48. Table 2 below summarizes EPCOR's applied-for 2016 and 2017 capital trackers, the portion of the K factor adjustments related to each capital tracker project or program, and the total applied-for K factor adjustment for each of 2016 and 2017.

⁴² Decision 20210-D01-2015, Table 3.

⁴³ Exhibit 20407-X0130.02, revised application, Table 1.0-2 on page 3.

⁴⁴ Exhibit 20407-X0192, paragraph 12.

Table 2. Applied-for 2016 and 2017 forecast capital tracker projects (\$ million)⁴⁵

No.	Project name	Applied-for K factor	
		2016	2017
	Applied-for projects or programs previously approved for capital tracker treatment		
1	Third-Party Driven Relocations	3.40	4.09
2	Life Cycle Replacement and Extension of Underground Distribution Cable	2.40	3.36
3	New 15-kV and 25-kV Circuit Additions	1.11	1.81
4	New Underground Cable and Aerial Line Reconfigurations and Extensions to Meet Customer Growth	1.30	1.72
5	Distribution Pole and Aerial Line Life Cycle Replacements	0.33	0.54
6	Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement	0.71	1.00
7	Capitalized Underground System Damage	0.71	0.94
8	Vehicles – Growth and Life Cycle Replacements [Note 1]	--	--
9	New Underground and Aerial Service Connections for Commercial, Industrial, Multi-family and Misc. Customers	1.77	2.50
10	Underground Residential Distribution (URD) Servicing – Rebates, Acceptance Inspections & Terminations	4.30	5.51
11	Capital Tools and Instrument Purchases	0.19	0.22
12	Poundmaker Feeders	0.44	0.40
13	OMS/DMS Life Cycle Replacement	1.44	1.79
14	Capitalized Aerial System Damage	0.23	0.32
15	Underground Industrial Distribution (UID) Servicing – Rebates, Acceptance Inspections & Terminations	0.30	0.44
16	Replacement of Faulted Distribution PILC Cables	0.30	0.39
17	Neighbourhood Renewal Program	0.28	0.24
18	Customer Revenue Metering – Growth & Life Cycle Replacements	4.60	2.30
19	Life Cycle Replacement of Network Transformers	0.37	0.54
20	Life Cycle Replacement of PILC Cable Systems	0.34	0.54
	Total previously approved capital trackers	24.52	28.65
	Applied-for projects or programs that have not been previously approved for capital tracker treatment		
21	Advanced Metering Infrastructure	2.12	5.89
22	Work Centre Redevelopment	0.59	2.49
23	IT Hardware Lifecycle Replacements and Additions	0.15	0.27
24	Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes	0.19	0.27
25	Switching Cubicle Life Cycle Replacement	--	0.13
26	Network Reconfigurations	--	0.32
27	Street Light Service Connections and Security Lighting Addition and Capital Replacement [Note 2]	--	0.12
	Total not previously approved trackers	3.05	9.49
	2016-2017 K factor total	27.57	38.16

Note 1: In the application, EPCOR applied for capital tracker treatment of the Vehicles – Growth and Life Cycle Replacements project. As a result of corrections, EPCOR determined that this project no longer qualifies for capital tracker treatment in each of 2016 and 2017. EPCOR withdrew its request for capital tracker treatment for this project.⁴⁶

⁴⁵ Exhibit 20407-X0130.02, revised application, Table 1.0-1 on page 2.

⁴⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-031.

Note 2: In Decision 3100-D01-2015, the Commission approved the need and forecast expenditures as part of the project assessment under Criterion 1 for the Street Light Service Connections and Security Lighting Addition and Capital Replacement project for 2015. However, this project was not afforded capital tracker treatment in 2015 because it did not meet the requirements of other capital tracker criteria on a forecast basis, as set out in the compliance filing Decision 20210-D01-2015, Table 4.

5 Grouping of projects for capital tracker purposes

49. In Decision 2013-435, the Commission determined that the accounting test and the first tier of the materiality test will be applied to the approved groupings (i.e., either at a project or at a program level). When necessary, however, the Commission will consider the individual component projects comprising the approved groupings in order to assess the need for the capital expenditures and the reasonableness of the forecast costs. The second tier of the materiality test will be applied at the level of all capital tracker projects, in the aggregate.⁴⁷ The Commission also determined that the reasonableness of the grouping of capital projects is best assessed on a case-by-case basis for each individual company.⁴⁸

50. EPCOR's proposed grouping of capital tracker projects is discussed in the two sections that follow. In Section 5.1, the Commission deals with EPCOR's general approach to grouping, including the compliance with previous Commission directions and reviews non-capital tracker projects for grouping purposes. Section 5.2 deals with issues that relate to grouping of certain projects proposed for capital tracker treatment in the application.

5.1 EPCOR's approach to grouping

51. In the application, EPCOR utilized the same approach to grouping as in previous capital tracker applications. This approach is generally based on the approximately 60 capital project categories that EPCOR used for purposes of its last three general tariff applications (GTAs) under cost-of-service regulation.⁴⁹

52. EPCOR's proposed grouping of capital tracker projects was generally approved in Decision 2013-435, with certain exceptions.⁵⁰ As well, in Decision 3100-D01-2015, while pointing to certain drawbacks of EPCOR's approach to grouping, the Commission accepted the approach as reasonable.⁵¹

53. While accepting the approach to grouping as generally reasonable, in Decision 3100-D01-2015, the Commission questioned whether all of EPCOR's life cycle replacement and like projects should be grouped together with the Neighbourhood Renewal program for the purposes of the accounting test, given that it appears these projects are all intended to replace or renew aging assets. The Commission directed EPCOR to explain, in its next capital tracker application, whether it is possible to do so and whether such a grouping is warranted.⁵²

⁴⁷ Decision 2013-435, paragraph 407.

⁴⁸ Decision 2013-435, paragraph 406.

⁴⁹ Decision 2013-435, paragraph 833.

⁵⁰ Decision 2013-435, paragraphs 837-841.

⁵¹ Decision 3100-D01-2015, paragraph 83.

⁵² Decision 3100-D01-2015, paragraph 78.

54. In its application, EPCOR responded to this direction and indicated that while grouping its “life cycle replacement projects together with the Neighborhood Renewal program is “technically possible, it would be impractical, burdensome and very costly.”⁵³ EPCOR indicated it has a number of projects and programs that, based on its historic approach to grouping, involve both life cycle replacement-driven and growth-driven work. According to EPCOR, disaggregating the Neighborhood Renewal program into component asset accounts to separate life cycle replacement work from non-life cycle replacement work so they can be grouped with other like activities “would be an immense, labour-intensive task.”⁵⁴

55. EPCOR also noted that based on its 2016 capital project forecast, there are 18 projects that include life cycle replacement work that currently do not satisfy the accounting test for capital tracker treatment. EPCOR pointed out that if these projects were grouped together with the Neighbourhood Renewal program, then as a group, they would satisfy the accounting test and these 18 additional projects would have to be included in one or more business cases and engineering studies, resulting in additional workload for the company and parties, since these additional projects would have to be subjected to scrutiny through the regulatory approval process for capital tracker treatment.⁵⁵

56. In Decision 3558-D01-2015, the Commission stated the following:

50. The Commission considers that a short description outlining the nature, scope and timing of non-capital tracker projects and programs will be of assistance in understanding the proposed grouping of capital projects and programs for capital tracker treatment. A requirement for a limited description should not be unduly onerous and may reduce the need for information requests from the Commission and parties. Accordingly, the companies are directed in their future capital tracker applications, starting with the 2014 true-up and 2016-2017 forecast applications, to provide descriptions of the types of capital for non-capital tracker projects or programs. The Commission has added this requirement to its revised minimum filing requirements in Appendix 3.⁵⁶

57. In the application, EPCOR provided a brief description of all non-capital tracker projects and programs, showing actual and forecast capital additions from 2014 to 2017.⁵⁷ The grouping of one such project, the Business System Upgrades non-capital tracker project, together with the proposed IT Hardware Lifecycle Replacements and Additions new capital tracker program, is discussed below in this section. The groupings of some of the other non-capital tracker projects that raise some concern are further discussed in Section 5.2 of this decision, dealing with the grouping of specific capital trackers.

58. EPCOR proposed a new capital tracker program, IT Hardware Lifecycle Replacements and Additions, which included an upgrade to a server platform with an operating system that runs several databases. EPCOR described a non-capital tracker project, Business System Upgrades that included database version upgrades. In response to a Commission IR regarding the validity of grouping the IT Hardware Lifecycle Replacements and Additions capital tracker

⁵³ Exhibit 20407-X0130.02, revised application, paragraph 21.

⁵⁴ Exhibit 20407-X0130.02, revised application, paragraph 22.

⁵⁵ Exhibit 20407-X0130.02, revised application, paragraph 24.

⁵⁶ Decision 3558-D01-2015, paragraph 50.

⁵⁷ Exhibit 20407-X0130.02, revised application, Table 2.1.6-1 on pages 59-62.

program separate from the Business System Upgrades project, EPCOR submitted that the non-capital tracker project, Business System Upgrades, is related to software upgrades, as opposed to hardware upgrades.⁵⁸ During the hearing, EPCOR further justified the grouping, confirming that the IT Hardware Lifecycle Replacements and Additions program includes all of the EPCOR hardware IT-related capital projects and historically EPCOR has grouped IT hardware capital projects separate from IT software capital projects.⁵⁹

59. Although the UCA and the CCA took issue with EPCOR's proposed grouping of certain new capital tracker projects as discussed in Section 5.2, they did not object to EPCOR's approach to grouping in general.

Commission findings

60. The Commission has reviewed EPCOR's explanation as to why grouping its life cycle replacement projects together with the Neighborhood Renewal Program is not warranted, and finds that EPCOR has complied with the direction at paragraph 78 of Decision 3100-D01-2015. As well, the Commission accepts EPCOR's explanation that it is reasonable to group hardware IT-related capital projects separately from software capital projects as EPCOR has done with its IT Hardware Lifecycle Replacements and Additions program, and its Business System Upgrades program, because this is consistent with how the company has accounted for the costs of these programs historically.⁶⁰

61. The Commission has also reviewed EPCOR's description of the nature, scope and timing of its non-capital tracker projects, which EPCOR provided so that parties could gain a better understanding of the proposed groupings of the capital projects and programs for which EPCOR is seeking capital tracker treatment, and finds that EPCOR has complied with the direction at paragraph 50 of Decision 3558-D01-2015. As set out in Section 5.2 of this decision, the Commission directs certain changes to EPCOR's groupings based on this review.

62. Consistent with the approach set out in previous capital tracker decisions, as described in in Decision 3558-D01-2015,⁶¹ to the extent that the groupings in the present 2014 true-up and 2016-2017 forecast capital tracker application are the same as approved in Decision 3100-D01-2015, the Commission will not re-evaluate those groupings in this decision, except to the extent that those groupings were subject to Commission directions or other issues arising in this proceeding. However, any new groupings that are proposed in this proceeding will be assessed by the Commission in this decision.

63. The Commission has reviewed EPCOR's proposed groupings of its new capital trackers, and, with the exception of the projects discussed in Section 5.2 below, the Commission finds that the proposed groupings of projects and programs is consistent with EPCOR's general approach to grouping based on the same capital project categories it has used historically, and they are, therefore, reasonable. The groupings of new capital tracker projects are approved as filed, subject to determinations set out in Section 5.2 of this decision.

⁵⁸ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-071(b).

⁵⁹ Transcript, Volume 3, page 350, line 2 to page 351, line 5 (Mr. Reimer).

⁶⁰ Transcript, Volume 3, page 350, line 2 to page 351, line 5 (Mr. Reimer).

⁶¹ Decision 3558-D01-2015, paragraph 51.

5.2 Grouping of certain new capital tracker projects

5.2.1 AMI project and Customer Revenue Metering – Growth & Life Cycle Replacements project

64. In response to a Commission IR, EPCOR indicated that during 2016 and 2017 forecast years, it will be installing AMI meters as part of both the Customer Revenue Metering – Growth & Life Cycle Replacements project and the AMI project. EPCOR provided the following explanation for this approach:

... The capital costs for the meters identified as growth and life-cycle replacements are included as part of the Customer Revenue Metering - Growth & Life Cycle Replacements project in Appendix A-16. The AMI Capital Tracker project only includes the capital cost additions associated with the estimated number of meters already installed in its service area as of the forecast start of the meter replacements (Q3 of 2015) and therefore in need of replacement with an AMI meter. When AMI meter stock is available from the AMI vendor in Q3, 2015, EDTI will commence use of AMI meters for growth and life-cycle replacements as part of the Customer Revenue Metering – Growth & Life Cycle Replacement project, and capture the capital cost additions within that project... This approach clearly separates annually recurring growth and replacement costs from AMI system implementation costs.⁶²

65. In response to an IR, EDTI-AUC-2015JUN26-003 (a),⁶³ EPCOR confirmed its position that the AMI and the Customer Revenue Metering – Growth & Life Cycle Replacements projects “could be grouped together because they’re basically related to the same thing,”⁶⁴ as EPCOR indicated in the prior Proceeding 3100. EPCOR also indicated that there are no impediments to grouping the two projects together for the remainder of the PBR term, while keeping separate line entries for the purpose of the single group accounting test and separate business cases for the purpose of project assessment, similar to the approach EPCOR currently takes with respect to the Third-Party Driven Relocations group of projects.⁶⁵

Commission findings

66. Since the K factor adjustments associated with both the AMI project and the Customer Revenue Metering – Growth & Life Cycle Replacements project are positive for the 2016 and 2017 forecast years, combining these two projects into a single group has no effect on the total K factor amount during this period. However, the Commission sees merit in grouping these two projects given that all new meters installed in 2016 and 2017 under both projects will be AMI meters and no non-AMI meters will be installed for growth or replacements.⁶⁶

67. In the application, and throughout the record in this proceeding, these two projects were addressed separately. For ease of reference and for better clarity, the Commission will address these two projects separately in this decision. However, in its compliance filing to this decision and in future capital tracker applications, the Commission directs EPCOR to group these two projects together under a “Customer Revenue Metering” program, while filing separate business

⁶² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-043(b).

⁶³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-003(a).

⁶⁴ Proceeding 3100, Transcript, Volume 4, pages 652-657 (Mr. Baraniecki).

⁶⁵ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-003(b).

⁶⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-043(d).

cases for the purpose of project assessment and retaining two different line entries in the accounting test model for these two grouped projects. This is similar to the approach that EPCOR currently uses for its Third-Party Driven Relocations program.

5.2.2 Work Centre Redevelopment project

68. In the application, EPCOR brought forward the Work Centre Redevelopment project for capital tracker treatment in 2016 and 2017. As discussed in Section 6.3.1, the project consists of EPCOR acquiring a new building and yard space at its North Service Centre (NSC) location, the redevelopment of its existing NSC and South Service Centre (SSC) buildings, the consolidation of EPCOR Distribution and Transmission employees from EPCOR Tower and the St. Albert Trail Service Centre (SATSC) to the NSC and SSC, and the transfer of EPCOR's training facility to the Winterburn location.⁶⁷

69. The North and South Service Centre Building Life Cycle Replacements project is one of EPCOR's non-capital tracker projects. This project is described by EPCOR as the ongoing replacement of the architectural, structural, electrical, and mechanical components of its NSC and SSC buildings. The project also includes capital improvements on those buildings that meet the operational needs of EPCOR.⁶⁸

70. In an IR response to the Commission, EPCOR explained why it did not choose to group the North and South Service Centre Building Life Cycle Replacement project with the Work Centre Redevelopment project for capital tracker purposes, despite the similarities between the two projects. EPCOR's view was that the Work Centre Redevelopment project has a defined scope, which includes acquiring a building and land, and a comprehensive renovation of the new and existing land and buildings. In comparison, EPCOR explained that the North and South Service Centre Building Life Cycle Replacements project consists of continuing capital maintenance, repairs and minor facility upgrades.⁶⁹

71. Given that both the North and South Service Centre Building Life Cycle Replacements project⁷⁰ and the Work Centre Redevelopment⁷¹ project include similar types of work on the same or related facilities, such as roof repairs, the Commission inquired during the hearing why EPCOR chose to create separate projects and how the scope of each project was determined. Mr. Baraniecki explained that the Work Centre Redevelopment project scope was framed by the opportunity to acquire a new building at the NSC location, followed by the estimate of redevelopment work that would be required to make the NSC location a viable workspace for the next 20 years.⁷² Mr. Baraniecki stated that a life cycle replacement project typically deals with repairs and replacements that arise without being specifically forecast for a given year.⁷³

⁶⁷ Exhibit 20407-X0075, Appendix A22, paragraph 1.

⁶⁸ Exhibit 20407-X0130.02, revised application, page 60, Table 2.1.6-1, line 14.

⁶⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-002.

⁷⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-002.

⁷¹ Exhibit 20407-X0075, Appendix A22, page 23.

⁷² Transcript, Volume 1, page 178, lines 7-13 (Mr. Baraniecki).

⁷³ Transcript, Volume 1, page 178, lines 18-24 (Mr. Baraniecki).

72. EPCOR further provided an example of how similar work could be included in both projects:

A. MR. BARANIECKI: ... roof repairs are generally much larger thing, more than the dollars that we're talking about that are forecast for this -- the north and south service centre lifecycle replacement projects -- sorry, replacements.
I mean, what would fall in here would be -- well, you know, perhaps patching a hole in the roof. If there's some structural thing that needs to happen to a roof as part of redeveloping these sites, that would fall within the project, the north -- the new work centre redevelopment project.⁷⁴

73. EPCOR also confirmed that there was no intentional delay of necessary repairs and maintenance that would otherwise have been completed under the North and South Service Centre Building Life Cycle Replacement project due to the Work Centre Redevelopment project.⁷⁵

74. In its argument, EPCOR provided the following summary of its position on how these two projects should be grouped:

345. The evidence demonstrates that the Work Centre Redevelopment Project is properly grouped separately from the North and South Service Building Life Cycle Replacements project. The Work Centre Redevelopment Project is a discrete, significant redevelopment project that involves the acquisition of a building and the surrounding land, as well as the redesign and renovation of those facilities and EDTI's existing facilities to accommodate EDTI's service centre needs over the long term. By comparison, the North and South Service Centre Building Life Cycle Replacements project encompasses minor repairs, maintenance, and upgrades as they become necessary to ensure the continued operation of EDTI's facilities. Given the meaningful differences, the projects should be grouped separately.⁷⁶

75. The Furniture Life Cycle Replacement project is another non-capital tracker project, that consists of purchasing new office furniture to support growth and organizational changes, as well as replacing current furniture that is worn or does not meet ergonomic requirements.⁷⁷ The furniture expenditures that are being incurred as part of the scope of the Work Centre Redevelopment project are included in the cost of that project rather than being included in the Furniture Life Cycle Replacement project.⁷⁸

76. EPCOR explained that the furniture expenditures included in the Work Centre Redevelopment project should not be included in the Furniture Life Cycle Replacement project because those furniture costs are being driven by the redevelopment of the NSC and SSC. Furniture expenditures included in the Furniture Life Cycle Replacement project are related to repair and replacement of old furniture and ergonomic changes to work stations.⁷⁹

⁷⁴ Transcript, Volume 1, page 174, line 22 to page 175, line 7 (Mr. Baraniecki).

⁷⁵ Transcript, Volume 1, page 179, lines 4-16 (Mr. Baraniecki).

⁷⁶ Exhibit 20407-X0233, EPCOR argument, paragraph 345.

⁷⁷ Exhibit 20407-X0130.02, revised application, page 60, Table 2.1.6-1, line 15.

⁷⁸ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-058(a).

⁷⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-058(c).

77. In addition, included in Schedule 2 of EPCOR's application was the Service Centre Consolidation project,⁸⁰ which EPCOR completed in 2006. In an IR response to the Commission, EPCOR explained that the Service Centre Consolidation project consisted of purchasing a building at its NSC location, and completing renovations and improvements to accommodate EPCOR employees and equipment.⁸¹ Another component of the Service Centre Consolidation project was the consolidation of EPCOR employees from other service centres and office locations to the expanded NSC.⁸²

78. The Commission also inquired as to why EPCOR did not choose to group the Service Centre Consolidation project with the Work Centre Redevelopment project for capital tracker purposes. EPCOR explained that they were not grouped together because each project has a distinct and defined scope with separate drivers. EPCOR stated that the driver for the Service Centre Consolidation project was the consolidation of smaller work centres into a larger location, whereas the driver for the Work Centre Redevelopment project was the age of the NSC facility and the requirement for renovation and expansion.⁸³

79. The issue of differences in scope and project driver between the Service Centre Consolidation project and the Work Centre Redevelopment project was discussed during the hearing by Mr. McNeil and Commission counsel:

Q. ... If they're both dealing with the acquisition of a building, they're both dealing with consolidation of functions, why are they so uniquely different that they couldn't be considered and grouped together?

A. MR. MCNEIL: In our response, we had focussed on the difference between the drivers between the projects. The drivers for the south service centre consolidation project was consolidating smaller centres into a larger one whereas the work centre redevelopment project drivers include age of facility and the need for expansion and redevelopment and the inadequacy of the existing EDTI facility space to meet our operational needs.

Q. It also involves consolidation of functions; right?

A. MR. MCNEIL: That's correct, from other EDTI employee locations.

Q. So am I correct that they both involve the acquisition of a building and surrounding land? Building 2 versus Building 3?

A. MR. MCNEIL: Yes, I would agree.

Q. And it necessitated some redevelopment in order to do that? Yes?

A. MR. MCNEIL: Yes, I would agree.

Q. And they both involve consolidation of various business functions? Yes?

A. MR. MCNEIL: Yes.⁸⁴

80. Mr. Baraniecki provided further explanation that while there are similarities between the Service Centre Consolidation project and the Work Centre Redevelopment project, the scope and

⁸⁰ Exhibit 20407-X0134.02, revised Schedule 2, Schedule 2.1.

⁸¹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-081(a).

⁸² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-081(a).

⁸³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-081(b).

⁸⁴ Transcript, Volume 1, page 181, line 24 to page 182, line 25 (Mr. McNeil).

scale of the former was significantly less given there was not as much redevelopment of the existing buildings as compared to the current Work Centre Redevelopment project.⁸⁵

81. EPCOR included the following table in its argument to demonstrate that if the Furniture Life Cycle Replacement project, the North and South Service Centre Building Life Cycle Replacements project, Work Centre Redevelopment project, and the Service Centre Consolidation project were grouped together, which EPCOR maintained it was opposed to, the new group would continue to meet the Criterion 3 materiality threshold:

Table 3. Capital funding shortfall amounts for the Work Centre Redevelopment project and non-capital tracker projects⁸⁶

Project title	2016 forecast K factor (\$ million)	2017 forecast K factor (\$ million)
Work Centre Redevelopment project	0.59	2.49
The North and South Service Centre Building Life Cycle Replacements project	(0.22)	(0.26)
Service centre Consolidation project	(0.13)	(0.15)
Furniture Life Cycle Replacement project	0.05	0.06
Total capital funding shortfall	0.29	2.14

82. In its argument, the CCA stated that EPCOR was only able to distinguish these projects based on scope and scale, rather than the drivers. The CCA expressed its view that the similarities between the two projects, such as consolidation of functions, building and land acquisition, and redevelopment, “far outweigh simple scope differences.”⁸⁷ Overall, the CCA recommended that the Service Centre Consolidation project and the Work Centre Redevelopment be grouped together.⁸⁸

83. The UCA did not raise any concerns with respect to the grouping of the Work Centre Redevelopment project.

Commission findings

84. The Commission has reviewed the information on the record of this proceeding regarding the Work Centre Redevelopment project and the non-capital tracker projects related to EPCOR’s NSC and SSC. The grouping of the Work Centre Redevelopment project with each individual non-capital tracker project is discussed, by project, below.

85. While EPCOR noted there are some differences between the timing and scope of the North and South Service Centre Building Life Cycle Replacements project and the Work Centre Redevelopment project,⁸⁹ there are a number of similarities between the two projects. These similarities include the service centres involved, repair activities completed (e.g., roof repairs),⁹⁰

⁸⁵ Transcript, Volume 1, page 183, lines 7-18 (Mr. Baraniecki).

⁸⁶ Exhibit 20407-X0233, EPCOR argument, page 114, Table 1.

⁸⁷ Exhibit 20407-X0234, CCA argument, paragraph 161.

⁸⁸ Exhibit 20407-X0234, CCA argument, paragraph 164.

⁸⁹ Exhibit 20407-X0233, EPCOR argument, paragraph 345.

⁹⁰ Exhibit 20407-X0075, Appendix A22, page 23; Exhibit 20407-X0146, EDTI-AUC-2015JUN26-002.

and replacement and upgrades to the buildings' mechanical, electrical, and structural systems.⁹¹ Accordingly, the Commission does not consider that the projects are sufficiently different in nature to warrant separate grouping for capital tracker purposes.

86. Regarding the Service Centre Consolidation project and the Work Centre Redevelopment project, the Commission is of the view that there are a number of similarities between the projects. While EPCOR stated that the driver for the Service Centre Consolidation project was the consolidation of service centres, and the driver for the Work Centre Redevelopment project was the need to redesign and redevelop its existing service centres to accommodate its facilities needs over the long term, the Commission agrees with the CCA and considers that the projects fundamentally constitute the same type of work.

87. This was highlighted during an exchange during the hearing where Mr. McNeil indicated that both projects involved the consolidation of EPCOR employees from various locations to its NSC and SSC, the purchase of a building and land at EPCOR's NSC location, and redevelopment of the buildings at the NSC location. Furthermore, the Commission notes that the building purchased and redeveloped at the NSC location, Building 2, as part of the Service Centre Consolidation project, is one of the buildings being redeveloped as part of the Work Centre Redevelopment project.⁹²

88. Accordingly, the Commission finds that the Work Centre Redevelopment project and the Service Centre Consolidation project, while completed at different times, consist of comparable work, including work on the same buildings, and have drivers that are sufficiently related to warrant being grouped together for capital tracker purposes.

89. The Furniture Life Cycle replacement project consists of costs related to repairing and replacing furniture, and making ergonomic changes to work stations at EPCOR's service centres. EPCOR explained that the Work Centre Redevelopment project also includes furniture expenditures related to the acquisition of the building at the NSC location and the redevelopment of the existing NSC and SSC locations. The Commission considers that both projects represent expenditures related to acquiring furniture and work stations for use at EPCOR's service centre locations. While the furniture expenditures related to the Work Centre Redevelopment project are being driven by the expansion and redevelopment of the work centres, the furniture related assets may eventually require replacement as part of the Furniture Life Cycle replacement project. Accordingly, the Commission finds that the Furniture Life Cycle replacement is sufficiently similar to components of the Work Centre Redevelopment project and have drivers that are sufficiently related to warrant being grouped together for capital tracker purposes.

90. Given the Commission's findings regarding the three non-capital tracker projects and the Work Centre Redevelopment project, the Commission directs EPCOR to include all four projects (Work Centre Redevelopment project, North and South Service Centre Building Life Cycle Replacements project, Service Centre Consolidation project and the Furniture Life Cycle replacement project) in a single group for the purposes of capital tracker analysis in its compliance filing to this decision, as provided by EPCOR in Table 3. Similar to the directions in

⁹¹ Exhibit 20407-X0130.02, updated application, page 60, Table 2.1.6-1, line 14; Exhibit 20407-X0075, Appendix A22, page 21, paragraph 29.

⁹² Exhibit 20407-X0075, Appendix A22, page 58; Exhibit 20407-X0146, EDTI-AUC-2015JUN26-081(a).

Section 5.2.1 above, while grouping these projects into a single program, EPCOR should continue filing separate business cases for the purpose of project assessment and showing different line entries in the accounting test model for these projects, as shown in Table 3. This is similar to an approach that EPCOR currently uses for its Third-Party Driven Relocations program.

91. In Section 6.3.1 of this decision, the Commission approves the need, as well as the reasonableness of EPCOR's proposed 2016 and 2017 scope, level, timing and forecast capital expenditures for the Work Centre Redevelopment project, subject to the adjustments and Commission directions applicable to all projects or programs set out in Section 6.1 of this decision. Given this finding, the Commission is prepared to accept the need and the scope, level, timing and forecast capital expenditures in 2016 and 2017 for other projects that the Commission has directed to be included in the group for capital tracker purposes, as included in EPCOR's accounting test schedules, and to be included in the compliance filing to this decision. In a similar vein, given the Commission's determinations in Section 8 that the Work Centre Redevelopment project satisfies the requirements of Criterion 2, the Commission is prepared to extend this finding to other projects that the Commission has directed to be included in the group for capital tracker purposes in the compliance filing to this decision. However, EPCOR shall provide complete business cases and analysis of the actual expenditures (as set out in the minimum filing requirements Decision 3558-D01-2015) for all projects included in this combined capital tracker group in its 2016 and 2017 capital tracker true-up applications. The Commission will reassess, in the compliance filing to this decision, this combined capital tracker group against the materiality requirements of Criterion 3.

5.2.3 Rebuild and/or Replace Civil Work for Downtown Vault and Manholes project

92. EPCOR is applying for capital tracker treatment for the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes project for 2016 and 2017. The current application is the first time that EPCOR has applied for capital tracker treatment for this project. This project consists of the life cycle rebuilding and replacement of network vaults and manholes on EPCOR's downtown Edmonton underground distribution network. Specifically, the work completed as part of this project includes either repairing or replacing deteriorated vault or manhole structures and repairing corrosion on network vault lids. EPCOR explained with respect to the vault and manhole structures, the deterioration that occurs over time includes corroding of the rebar, rusting of the steel supports, and spalling of the concrete.⁹³

93. In the application, EPCOR provided a list and description of non-capital tracker projects and programs for 2014 to 2017. Included on that list were the DAM – Distribution Manhole Rebuilds project and the DAM – Interior Vault Life Cycle Replacement Conversion program, both of which have actual and forecast capital additions over the period of 2014 to 2017.

⁹³ Exhibit 20407-X0072, Appendix A-24, paragraphs 5-6.

94. EPCOR explained that the DAM – Distribution Manhole Rebuilds project consists of the following:

This life cycle replacement project includes the replacement of components in manholes to rebuild the cable support and grounding systems in EDTI's distribution manhole system, excluding the downtown network.⁹⁴

95. EPCOR provided the following explanation of the work performed as part of the DAM – Interior Vault Life Cycle Replacement Conversion program:

This life cycle replacement project includes the replacement of equipment which has reached the end of its useful life that is located inside interior vaults (rooms) located inside buildings at customer sites. In conjunction with the life cycle replacement of the equipment, EDTI will relocate the equipment to the exterior of the customers' buildings. EDTI currently has equipment in 71 customer-owned vaults that are located within buildings at customer sites. The equipment generally includes transformers, primary and secondary cable, primary switches and other related equipment owned by EDTI and used to provide electrical service to the building.⁹⁵

96. In an IR to EPCOR, the Commission sought clarification as to why EPCOR chose to group the capital tracker Rebuild and/or Replace Civil Work for Downtown Vault and Manholes project separately from either the DAM – Distribution Manhole Rebuilds project or the DAM – Interior Vault Life Cycle Replacement Conversion program. EPCOR responded that the project categories presented in its application are the ones it had used in the past, and that approach allows EPCOR to apply the accounting test on a project by project basis.⁹⁶

97. During the hearing, Ms. Hull, for EPCOR, explained that the structure of the downtown vaults and manholes was typically built with bricks, whereas the manholes outside of downtown were poured, precast structures. The structure of vault roofs that are being rebuilt or replaced downtown are grates as compared to the manhole covers that are metal plates. Ms. Hull further explained with respect to the work done on the two projects, for the downtown vaults the roof typically requires replacement due to heaving or collapsing from being driven over, as compared to the manholes outside downtown that do not experience similar heaving and as a result, the rebuild is focused on components within the manhole.⁹⁷

98. Ms. Hull also provided clarification on what is contained in a downtown vault as compared to a distribution manhole:

The work would be different for a downtown vault versus, let's say, a distribution manhole. And the reason being is the vaults within the downtown, they'll hold the transformers. But within that vault, there's also all the cabling and the supports to hold all the network cabling that is basically a ring around that structure, and there's all the uprights holding those cable trays, which you wouldn't see in, let's say, a distribution manhole where you would just have the cables running through the manhole and the splices being held on the wall by a few uprights.

⁹⁴ Exhibit 20407-X0130.02, revised application, page 59, Table 2.1.6-1.

⁹⁵ Exhibit 20407-X0130.02, revised application, page 59, Table 2.1.6-1.

⁹⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-001.

⁹⁷ Transcript, Volume 1, pages 163-164 (Ms. Hull).

So there's more components within a downtown manhole. Also there's more volume of cables running within the downtown; therefore, more components just to hold the volume of cables.⁹⁸

99. During the hearing, Commission counsel inquired as to whether the same crews performed work encompassed by the capital tracker project and the two non-capital tracker projects:

Q. Well, any work that has to be -- that's encompassed by those three different projects.

A. MS. HULL: The network system is a different system than our distribution system. So we have specialized network crews on the trade side as well as on the civil side. Those network crews, because they're specialized, could go out into the distribution network, but because of the nature of the work and the volume of the work, they stay within the downtown system and work within the downtown system.

Q. And they handle both the vaults and the downtown manholes.

A. MS. HULL: Correct.

Q. Okay. So they would have the basic skills to do all the system, but there's additional skill sets they require to do both the equipment repairs and replacements, as well as the civil construction issues; is that right?

A. MS. HULL: Yes.⁹⁹

100. In its argument, EPCOR maintained that the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes capital tracker project was distinct from the non-capital tracker projects given that these groupings represent the historical categories used by the company. EPCOR's view was that using these groupings assists in the Commission's understanding of capital expenditure trends.¹⁰⁰

101. Neither the UCA nor the CCA raised any concerns with respect to the grouping of the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes project.

Commission findings

102. Regarding the DAM – Interior Vault Life Cycle Replacement Conversion program, the Commission has examined the submissions put forth by EPCOR in its IRs, during the hearing, and in its written argument. The Commission agrees with EPCOR's view that the DAM – Interior Vault Life Cycle Replacement Conversion program is sufficiently different from the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes capital tracker project so it should remain separate from the DAM – Interior Vault Life Cycle Replacement Conversion program.

103. The Commission has reviewed the record of this proceeding with respect to the possibility for a common grouping for the DAM – Distribution Manhole Rebuilds project and the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes capital tracker project. Both are life cycle replacement projects related to structural components of manholes and vaults in EPCOR's distribution network. In addition, based on the project descriptions provided by

⁹⁸ Transcript, Volume 1, page 165, line 23 to page 166, line 13 (Ms. Hull).

⁹⁹ Transcript, Volume 1, page 168, lines 3-21 (Ms. Hull).

¹⁰⁰ Exhibit 20407-X0233, EPCOR argument, paragraph 421.

EPCOR, similar work is completed as part of each project, with one of the dissimilarities being the location where the work is completed. EPCOR further explained that there can also be differences in the amount of cable and associated components of a downtown manhole relative to a manhole outside of downtown.

104. Given that both the DAM – Distribution Manhole Rebuilds project and the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes projects consist of life cycle replacements of structural components of manholes and that downtown work crews are able to undertake the required work for either project, the Commission considers that the DAM – Distribution Manhole Rebuilds project and the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes capital tracker project are sufficiently similar in nature, and have drivers that are sufficiently related to warrant being grouped together for capital tracker purposes. EPCOR is directed to group these projects together in the compliance filing to this decision.

105. Similar to the directions in sections 5.2.1 and 5.2.2 above, while grouping these projects into a single program, EPCOR should continue to file separate business cases for the purposes of project assessment and show two different line entries in the accounting test model for these projects. This is similar to the approach that EPCOR currently uses for its Third-Party Driven Relocations program.

106. In Section 6.3.3 of this decision, the Commission approves the need, as well as the reasonableness of EPCOR's proposed 2016 and 2017 forecast capital expenditures for the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes project, subject to the adjustments and Commission directions applicable to all projects or programs set out in Section 6.1 of this decision. Given this finding, the Commission is prepared to accept the need and the scope, level, timing and forecast capital expenditures in 2016 and 2017 for the DAM – Distribution Manhole Rebuilds project, as included in EPCOR's accounting test schedules for purposes of the compliance filing to this decision. In a similar vein, given the Commission's determinations in Section 8 that the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes project satisfies the requirements of Criterion 2, the Commission is prepared to extend this finding for the DAM – Distribution Manhole Rebuilds project for purposes of the compliance filing to this decision. However, EPCOR shall provide complete business cases and analysis of the actual expenditures (as set out in the minimum filing requirements Decision 3558-D01-2015) for all projects included in this combined capital tracker group in its 2016 and 2017 capital tracker true-up applications. The Commission will reassess, in the compliance filing to this decision, this combined capital tracker group against the materiality requirements of Criterion 3.

6 Project assessment under Criterion 1 – the project must be outside of the normal course of the company's ongoing operations

107. As discussed in Section 3 of this decision, consistent with paragraph 841 of Decision 2013-435, each of EPCOR's projects or programs proposed for capital tracker treatment will be evaluated against the project assessment requirements of Criterion 1. The purpose of the project assessment component of Criterion 1 is to demonstrate that a project proposed for capital tracker treatment is required in order to maintain utility service at adequate levels, as required by paragraph 594 of Decision 2012-237, and that the actual scope, level, and timing of the project

are prudent and that costs of the project are reasonable for forecast projects and prudent for completed projects.

108. EPCOR's capital trackers applied for in this application can be broadly divided into two categories. The first category consists of applied-for projects or programs previously approved for capital tracker treatment in either Decision 2013-435 or in Decision 3100-D01-2015. As set out in Section 4 of this decision, this category includes all of the projects or programs comprising the 2014 true-up and the majority of projects or programs forming part of the 2016 and 2017 forecasts. The second category consists of the remaining projects or programs to be implemented in 2016 or 2017 that have not been previously approved for capital tracker treatment.

109. EPCOR provided a business case together with an engineering study (where EPCOR considered either document to be applicable) for each of its projects or programs proposed for capital tracker treatment in 2016 or 2017. In its business cases, as supplemented by other evidence filed in the proceeding, EPCOR has generally provided an assessment of proposed capital tracker projects or programs consistent with the minimum filing requirement guidelines set out in Decision 2013-435, and subsequently refined in Decision 3558-D01-2015.

110. The Commission has evaluated the EPCOR business cases, engineering studies, cost related information, and related evidence and argument against each of the project assessment minimum filing requirements. However, for the purposes of this decision, the Commission has commented only on those aspects of the minimum filing requirements that the Commission considers are insufficiently addressed by EPCOR's evidence or were otherwise raised as an issue in the proceedings. In future capital tracker applications, EPCOR should continue to provide similar information with respect to each of the minimum filing requirements, including business cases, engineering studies and cost related information, including costs by cost category, unit costs and historical cost comparators, in sufficient detail to allow an evaluation of the reasonableness of its forecasts and the prudence of its incurred costs.

111. The balance of this section is organized as follows: Section 6.1 deals with common issues related to the project assessment of EPCOR's projects, such as assumptions in developing EPCOR's capital expenditure forecasts, proposed capitalization of short-term incentive pay, affiliate transactions, the company's internal cost controls and accountability mechanisms with respect to quality, safety and cost for capital projects approved for capital tracker treatment and asset usage fees. The Commission's project assessment under Criterion 1 of EPCOR's projects or programs previously approved for capital tracker treatment in either Decision 2013-435 or in Decision 3100-D01-2015, is set out in Section 6.2. The project assessment of EPCOR's projects or programs that have not been previously approved for capital tracker treatment is set out in Section 6.3. Given the complexity of issues related to the Customer Revenue Metering – Growth & Life Cycle Replacements project and the AMI project, which the Commission directed to be grouped together under the Customer Revenue Metering program, these two projects are considered in a separate section, Section 6.4.

6.1 Common issues

6.1.1 Common assumptions in EPCOR's capital expenditure forecasts

112. EPCOR indicated that for the purposes of the 2016 and 2017 capital tracker forecasts, project estimates were generally prepared by internal resources, and in some cases by external consulting engineers with direct involvement in certain projects. The forecasts were developed

using a bottom up approach whereby EPCOR staff entered the specific project work components (labour, materials, vehicles, contractors) into its computerized Work Management System, or when detailed information was not available, forecasts were developed using a three-year normalized historical actual average costs methodology.

113. EPCOR indicated that its 2016 and 2017 capital expenditures were forecast in 2015 dollars, by expense type such as union labour, engineering, materials, contractors and vehicles. All costs were then inflated using escalation factors for 2016 and 2017. EPCOR applied employee fringe benefits to all inflated labour costs and then applied a capital overhead amount to arrive at the final estimates.

114. EPCOR explained that because the 2016 and 2017 forecast capital expenditures will be trued up to actual costs, EPCOR did not engage external consultants to provide forecasts and reports in support of the company's chosen escalation factors, as was its practice under cost-of-service regulation.

115. EPCOR used the following inflation factors for its 2016 and 2017 capital tracker forecasts:

- A four per cent salary escalation factor was applied for non-union staff for both years.
- For unionized employees, a three per cent salary escalation was applied for the International Brotherhood of Electrical Workers (IBEW) and the Civic Service Union (CSU) staff for both years.
- For both years, employee fringe benefit rates of 43.65 per cent were applied to all salary and labour costs.
- Material cost inflators were 2.2 per cent for both years. For 2016 and 2017, contractor cost inflators were 3.1 per cent and 3.2 per cent, and inflators for other costs were 2.1 per cent and 2.0 per cent, respectively.¹⁰¹

116. For labour cost forecasts, EPCOR used a man-hours by employee classification and applied standard rates based on available collective bargaining agreements. New collective bargaining agreements for members of the IBEW and the CSU had not been finalized when EPCOR submitted the application and, therefore, to derive the 2016 and 2017 labour rates, EPCOR applied an escalation factor to the 2015 IBEW and the 2013 CSU collective bargaining agreement rates, as applicable.

117. EPCOR confirmed that the 2016 and 2017 forecast escalation factors used for union staff were provided by EPCOR Utilities Inc. for budgetary purposes in January 2015. This was subsequent to the filing of the 2015-2017 transmission facility owner (TFO) tariff application, which used escalation factors based on the Conference Board of Canada's July 25, 2014 forecast of growth in wages of 3.1 per cent and 3.2 per cent for 2016 and 2017, respectively.¹⁰²

118. In response to a CCA IR,¹⁰³ EPCOR indicated that for the CSU union workers, a memorandum of agreement was concluded after this application was submitted, which covers the

¹⁰¹ Exhibit 20407-X0130.02, revised application, paragraphs 155-156.

¹⁰² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-015.

¹⁰³ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-008(c).

period 2014 to 2017. The agreement sets out a range of increases dependant on employee classification. The ranges are as follows:

2014 – 3.50 to 4.00 per cent
2015 – 3.00 to 3.50 per cent
2016 – 2.25 to 2.50 per cent
2017 – 2.15 to 2.40 per cent

119. EPCOR indicated that its 2016 forecast escalation factor for non-union (salary) staff was determined on the advice provided by Towers Watson in respect of the level of escalation applicable to non-union salaries for 2016, and was consistent with the escalation factors used in its 2015-2017 TFO tariff application, reviewed in Proceeding 3539. For 2017, EPCOR used the same escalation factor that it applied in its 2016 forecast. EPCOR noted that the Towers Watson report had recommended a range of three per cent to four per cent for 2016.¹⁰⁴

120. Engineering salary costs were estimated on a man-hour basis by resource type using standard engineering rates based on actual payroll costs. The 2016 and 2017 salary costs were based on 2015 actual payroll costs.

121. In its application, EPCOR provided a table showing the employee fringe benefit component costs as a percentage of base compensation from 2012 to 2017. In response to an IR, EPCOR noted that the 2013 rates shown in the table were incorrect and provided an updated table.¹⁰⁵ EPCOR explained that its employee fringe benefit rates increased from an actual 41.3 per cent in 2012 to a forecast of 43.65 per cent in each of 2016 and 2017. EPCOR explained that the 2.35 per cent increase was due to a 1.84 per cent increase in contribution rates for the Local Authorities Pension Plan (LAPP) and a 0.54 per cent increase in health, dental and group life benefit rates, offset by a 0.03 per cent decrease in other fringe benefits. EPCOR noted that contribution rates for the LAPP are determined by the LAPP administrator and are not under EPCOR's control.¹⁰⁶

122. In this application, EPCOR used the eight per cent 2015 capital overhead rate that was used in its 2015-2017 TFO tariff application in preparing its forecasts for both 2016 and 2017. The eight per cent rate was determined by dividing the 2015 estimated capital overhead pool costs by total forecast capital expenditures for each of EPCOR's transmission and distribution functions.¹⁰⁷ The 2015 overhead rate was used because EPCOR had not completed its operating budget for 2016 and 2017 at the time it filed the present application.¹⁰⁸ EPCOR applied a capital overhead amount to the cost of capital projects using the capital overhead rate of eight per cent (with the exception of the Work Centre Redevelopment project and the AMI project) to determine the total forecast capital project budget.

123. The Work Centre Redevelopment project and the AMI project were allocated capital overhead at a rate of one per cent. EPCOR explained that because these projects are primarily supervised on a day to day basis by contractors rather than by internal staff, EPCOR considered

¹⁰⁴ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-008(b).

¹⁰⁵ Exhibit 20407-X0146, Table EDTI-AUC-2015JUN26-017-1.

¹⁰⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-017.

¹⁰⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(a).

¹⁰⁸ Exhibit 20407-X0130.02, revised application, paragraph 159.

that using a standard overhead allocation rate would not lead to an appropriate allocation of capital overhead relative to the level of underlying internal supervision work required on these projects. EPCOR indicated that this approach is consistent with its methodology of applying a one per cent overhead rate to its AESO-directed transmission capital projects, which are also executed in a similar manner.¹⁰⁹

124. In an IR, EDTI-AUC-2015JUN26-018, the Commission asked EPCOR to provide an estimate of its 2016 and 2017 capital overhead pool amounts assuming an eight per cent overhead rate. The Commission also asked EPCOR to provide a table showing the items that make up the capital overhead pool amounts, and to explain any year-over-year cost increases exceeding I-X. In the IR response, EPCOR stated that its capital overhead pool is composed solely of labour and salary costs that are considered directly attributable to capital projects and includes labour and salaries related to both the distribution and transmission functions. Therefore, EPCOR explained that it estimated its 2016 and 2017 capital overhead pool amounts as follows:

EDTI's distribution function has not forecast the costs related to its specific operating and capital cost categories for 2016 and 2017, as it is under Performance Based Regulation. Therefore, EDTI is not able to calculate its 2016 and 2017 Forecast total capital overhead pool amount or allocation percentages using the same approach it used to calculate its 2015 forecast amounts or percentages. EDTI calculated the 2016 and 2017 total capital overhead pool amounts [...] by escalating the 2015 total capital overhead pool amount by 3.4% in both 2016 and 2017. As the capital overhead pool is comprised of salary and labour, EDTI used 3.4% as an escalation factor based on the Conference Board of Canada's wages and salary escalator forecast (as of July 25, 2014) for a composite of industries in the province of Alberta.¹¹⁰

125. During the hearing, EPCOR clarified that the 3.4 per cent escalation factor assumption blended the forecast 3.0 per cent increase for union staff and the 4.0 per cent increase for non-union staff.¹¹¹

126. EPCOR justified the 22 per cent increase in capital overhead pool amounts allocated to its distribution function from 2014 actual to 2015 forecast by demonstrating that the capital overhead pool allocation increased in exactly the same proportion as capital expenditures, as shown in the table below.¹¹² EPCOR provided the following table comparing 2014 approved to 2015 forecast capital overhead pool amounts.

¹⁰⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-019(a).

¹¹⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(a).

¹¹¹ Transcript, Volume 1, page 200, lines 10-18 (Mr. Chaudhary).

¹¹² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(b).

Table 4. Allocation of capital overhead pool and capital expenditures 2014-2015¹¹³

Description	2014 actual	2015 forecast	Difference
	(\$ million)		(%)
1 Distribution capital overhead pool – non 1% projects	9.30	11.22	21
2 Distribution capital overhead pool – 1% projects	0.09	0.23	155
3 Total distribution capital overhead pool	9.39	11.44	22
4 Capital expenditures subject to overhead– non 1% projects	112.14	134.03	20
5 Capital expenditures subject to overhead – 1% projects	8.90	22.51	153
6 Total capital expenditures subject to overhead pool	121.04	156.54	29
7 Capital overhead rate – non 1% projects (=row 1/ row 4)	8.3%	8.4%	-
8 Capital overhead rate – 1% projects (=row 2/ row 5)	1%	1%	-

Note: The “1% projects” notation refers to the Work Centre Redevelopment project and the AML project, to which an overhead rate of one per cent has been applied.¹¹⁴

127. The eight per cent escalator capital overhead rate was determined using the assumption that the capital overhead pool allocation increases from 2014 to 2015, and then to 2016 and 2017, in exactly the same proportion as capital expenditures.¹¹⁵ In response to a CCA IR,¹¹⁶ EPCOR clarified that the difference between the 8.4 per cent 2015 rate and the 8.0 per cent capital overhead rate used for the purpose of the 2016 and 2017 forecasts arises because, on a forecast basis, the overhead rate applied to capital projects is based on a rate rounded to a whole percentage.

128. In its argument, the CCA suggested that the forecast allocated overhead should be based on the 2016 I factor of 2.06 per cent, instead of the 3.4 per cent proposed by EPCOR.¹¹⁷ In reply, EPCOR reiterated that in the calculation of its capital overhead costs, it applied a capital overhead rate of eight per cent to the cost of each capital project and that the CCA’s suggestion to use the I factor was not relevant.¹¹⁸

129. The CCA also expressed a concern that statutory holiday and vacation costs may be double counted in overhead rates when costs are allocated to capital and operating projects from an employee’s home account.¹¹⁹ In its reply argument, EPCOR provided an illustration to show how the costs are allocated, and further confirmed that there is no double counting:

... if EDTI has an employee that is not assigned to specific operating and/or capital projects, all costs related to paid vacation and statutory holidays would stay in the home account. If an employee works on a specific operating or capital project, costs would be transferred from the home account to the specific operating or capital project based on the time spent working on that specific project. If that same employee goes on vacation while working on that specific operating or capital project, the salary cost related to the employee’s time spent on vacation remains in the home account until the standard fringe rate is applied to allocate cost to that specific project. For example, if the employee

¹¹³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(b), Table EDTI-AUC-2015JUN26-018-2.

¹¹⁴ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(b).

¹¹⁵ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(b).

¹¹⁶ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-011(a).

¹¹⁷ Exhibit 20407-X0234, CCA argument, paragraphs 169-181.

¹¹⁸ Exhibit 20407-X0237, EPCOR reply argument, paragraphs 76-79.

¹¹⁹ Exhibit 20407-X0234, CCA argument, paragraphs 54-55.

spends 25% of his or her time on a project, then 25% of the employee's transfer burden (i.e., vacation, statutory holidays, etc.) will be allocated to that specific operating or capital project.

...

In summary, there is no double counting of costs related to vacation or statutory holidays. EDTI applies the same standard fringe rate to both capital and operating projects.¹²⁰

130. Material and contractor resources were estimated using current costs based on the scope of work identified by the group initiating the work. Where available, EPCOR used cost information from similar previously constructed projects. EPCOR used external resources, such as suppliers of materials and construction contractors, to assist in developing expenditure forecasts. For special order material not maintained in stock, EPCOR consulted suppliers for forecast estimates of the required materials. Construction contractors were also consulted for forecast estimates for specialized construction services normally not carried out by EPCOR's internal labour force.

Commission findings

131. EPCOR applied for a 4.0 per cent escalation factor for non-union (salary) employees for 2016 and 2017, based on a Towers Watson report on the level of escalation applicable to non-union salaries for 2016. The Towers Watson report had recommended a range of three per cent to four per cent for 2016.¹²¹

132. Evidence in this proceeding suggests that salary escalation rates are on a downward trend. EPCOR indicated that, subsequent to proposing the Conference Board of Canada rates of 3.1 per cent and 3.2 per cent used in its 2015-2017 TFO application, the 3.0 per cent escalation factor included in the present application for EPCOR's unionized employees, was provided by EPCOR Utilities Inc. to all EPCOR business units in January 2015 for use in preparation of their 2016 budgets.¹²² As well, the actual 2014 to 2017 negotiated salary escalation rates for EPCOR's CSU employees, clearly demonstrate the downward trend for unionized employees, as further discussed below. In light of these trends, the Commission does not accept EPCOR's recommendation to use rates at the high end of the Towers Watson report for non-unionized employees. The Commission considers an escalation rate of 3.0 per cent, which is at the lower range of the recommendation in the Towers Watson report, to be reasonable for the purposes of determining the non-union labour cost associated with proposed capital tracker expenditures for 2016 and 2017. The Commission directs EPCOR to reflect these non-union employee escalation rates in its compliance filing application to this decision.

133. A portion of EPCOR's labour and salary costs related to unionized employees is based on the negotiated results of collective bargaining agreements between EPCOR and employee unions. Since no collective bargaining agreements were in place for 2016 and 2017, EPCOR indicated that it applied a three per cent salary escalation factor to the 2015 IBEW and the 2013

¹²⁰ Exhibit 20407-X0237, EPCOR reply argument, paragraphs 51-53.

¹²¹ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-008(b).

¹²² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-015.

CSU collective bargaining agreement rates, as applicable, to derive the 2016 and 2017 labour rates.

134. As noted above, evidence in this proceeding suggests that salary escalation rates are on a downward trend as most recently demonstrated by the collective bargaining agreement negotiated by EPCOR with the CSU union workers for 2014 to 2017. The CSU agreement sets out a range of increases dependent on employee classification, ranging from 3.50 to 4.00 per cent in 2014, from 2.25 to 2.50 per cent in 2016, and from 2.15 to 2.40 per cent in 2017.¹²³ The Commission directs EPCOR to reflect the 2016 and 2017 ratified collective agreement CSU employee escalation rates in the compliance filing to this decision. In light of the downward trend in salary escalation rates, the Commission considers that an escalation rate of 2.5 per cent for IBEW unionized labour is reasonable for purposes of the accounting test to be used in forecasting 2016 and 2017 capital trackers. The Commission directs EPCOR to reflect the 2.5 per cent labour escalation rate for the IBEW unionized workers in the compliance filing to this decision.

135. Additionally, the Commission directs EPCOR, in its compliance filing to this decision, to account for the actual 2014 escalation rate for CSU and IBEW union workers under their respective collective bargaining agreements in the 2014 capital tracker true-up. In the compliance filing to this decision, EPCOR is also directed to explain the adjustments it has made to the 2014 capital tracker true-up, to account for the actual 2014 escalation rates as per its collective bargaining agreements.

136. For 2016 and 2017, EPCOR proposed contractor cost inflators of 3.1 per cent and 3.2 per cent, materials cost inflators of 2.2 per cent for both years, and inflators for other costs of 2.1 per cent and 2.0 per cent, respectively.¹²⁴ In response to a CCA IR, EPCOR acknowledged that these escalation factors were slightly different from the escalation factors used in Table 2.2-5 of the application, as the latter were based on updated numbers. However, EPCOR stated that the differences are not significant.¹²⁵

137. Consistent with its determinations on the escalation rates for the non-union employees, the Commission directs EPCOR to limit the increase in contractor costs to three per cent in each of 2016 and 2017. The Commission finds the escalation rates for other costs of 2.1 per cent and 2.0 per cent, for 2016 and 2017, respectively, and the materials escalation rates of 2.2 per cent for both years proposed by EPCOR to be reasonable.

138. Finally, regarding the escalation factors, the Commission observes that EPCOR forecast capital expenditures for a number of projects (listed in EDTI-AUC-2015JUN26-014¹²⁶) using its three-year normalized historical actual average costs methodology that relies on certain escalation factors, including labour, materials, contractors, vehicles and equipment as set out in Table 2.2-5 of the application.¹²⁷ In the Commission's view, the escalation factors used in this table for the purposes of forecasting expenditures for capital tracker projects that rely on the

¹²³ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-008(c).

¹²⁴ Exhibit 20407-X0130.02, revised application, paragraph 155(d).

¹²⁵ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-009(a).

¹²⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-014.

¹²⁷ Exhibit 20407-X0130.02, revised application, Table 2.2-5 on page 69, revised in Exhibit 20407-X0154, EDTI-CCA-2015JUN26-009(a), Table EDTI-CCA-2015JUN26-009-1.

normalized methodology should be consistent with the escalation factors used in the balance of the application for other capital tracker projects. Therefore, in its compliance filing to this decision, EPCOR is directed to provide an updated Table 2.2-5 reflecting the escalation factors consistent with the Commission's approvals above, and to explain how it recalculated the resulting forecast 2016 and 2017 capital expenditures for (i) projects that used the normalized methodology, as compared to (ii) the remaining projects employing forecasts based on EPCOR's bottom-up approach.

139. The Commission has reviewed EPCOR's explanations regarding the increase in the employee fringe benefit rates from an actual 41.3 per cent in 2012 to a forecast of 43.65 per cent in each of 2016 and 2017, and finds them to be reasonable. Forecast rate increases of 43.65 per cent for employee fringe benefit in each of 2016 and 2017, are approved as filed.

140. In paragraph 391 of Decision 2014-373¹²⁸ dealing with AltaGas Utilities Inc.'s 2013-2015 capital tracker applications, the Commission considered that generally, it would be reasonable for a company to limit the escalation rate of its overhead pool items to I-X, unless it can demonstrate that an increase in excess of this amount is prudent:

391. ... The company must also be prepared to explain any significant year-over-year changes in the items that make up the overhead pool. To the extent that a company limits the year-over-year increases to an item in the overhead pool to I-X, as AltaGas has done with inter-affiliate costs, the Commission considers that to be a reasonable approach for capital tracker purposes. However, a company is not required to limit its increases to its overhead items to I-X if it can demonstrate that an increase in excess of this amount is prudent.

141. EPCOR explained that it has not forecast the costs related to its specific operating and capital cost categories for its distribution function for 2016 and 2017, as it is under PBR. Rather, EPCOR applied a capital overhead amount to the cost of the capital projects using the capital overhead rate of eight per cent (one per cent for the Work Centre Redevelopment and the AMI projects), based on the calculated 2015 overhead rate used in EPCOR's 2015-2017 TFO tariff application.¹²⁹ This method implies that capital overhead pool allocations increase from 2014 to 2015, and then to 2016 and 2017 in exactly the same proportion as increases in capital expenditures.¹³⁰

142. However, the Commission considers that the assumption that capital overhead pool allocations increase in exactly the same proportion as increases in capital expenditures may not be accurate because of possible economies of scale available to the company as the capital overhead pool is increased. The Commission is also not persuaded that EPCOR has demonstrated for the purposes of this application, that a 22 per cent increase in capital overhead pool amounts allocated to its distribution function from 2014 actual to 2015 forecast¹³¹ is

¹²⁸ Decision 2014-373: AltaGas Utilities Inc., 2014-2015 Capital Tracker Application and 2013 Capital Tracker True-up Application, Proceedings 3152 and 3244, Applications 1610446-1 and 1610600-1, December 24, 2014.

¹²⁹ Exhibit 20407-X0130.02, revised application, paragraph 159 and Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(a).

¹³⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(b).

¹³¹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(b).

reasonable and can serve as a justification for forecasting the capital overhead portion of the 2016 and 2017 expenditures associated with capital tracker projects.

143. In the absence of evidence supporting EPCOR's proposed overhead costs, the Commission cannot approve an increase in overhead costs in excess of the previous year's amount adjusted by I-X. Therefore, consistent with the provisions of paragraph 391 of Decision 2014-373 referenced above, the Commission finds that for purposes of the 2016 and 2017 capital tracker forecasts, the escalation rate of EPCOR's overhead pool items should be limited to I-X. In the respective capital tracker true-up applications, adjustments for overhead costs in excess of I-X would require evidence demonstrating a higher level of prudently incurred costs. This is consistent with the Commission findings in Decision 3220-D01-2015¹³² and Decision 3267-D01-2015,¹³³ where similar determinations were made for FortisAlberta's and ATCO Gas's 2013 to 2015 overhead amounts, given that there was not sufficient evidence to substantiate the proposed increases in corporate allocations in excess of I-X.

144. The Commission directs EPCOR, in its compliance filing to this decision, to recalculate the capital overhead amounts included in the forecast capital expenditures for its 2016 and 2017 capital tracker projects, based on the capital overhead forecast calculated by applying the approved I-X indexes for 2015 and 2016 and EPCOR's estimate for the 2017 I-X index used in the accounting test (discussed in Section 7.1) to the 2014 actual capital overhead amounts. The obtained capital overhead amounts can then be allocated to EPCOR's capital tracker and non-capital tracker projects, consistent with the company's capitalization and allocation methodologies, provided that EPCOR will retain the existing distinction in capital overhead allocation for the "1 per cent projects," (the Work Centre Redevelopment and the AMI projects) from other capital projects.¹³⁴ In doing so, EPCOR should also remove from the 2014 actual and 2016 and 2017 forecast capital overhead amounts any capitalized STIP amounts, as directed in Section 6.1.2 of this decision.

145. Regarding the possibility of double-counting statutory holiday and vacation costs in overhead rates, the Commission finds EPCOR's explanation¹³⁵ sufficient to deal with the concern expressed by the CCA.

146. In the application and in response to IRs, EPCOR indicated that the escalation factors and capital overhead rate proposed in this application were generally the same numbers put forward in EPCOR's 2015-2017 TFO tariff application. The Commission recognizes that in Decision 3539-D01-2015 dealing with that application, it approved certain escalation factors and a capital overhead rate that may differ from the Commission's approvals for the 2016 and 2017 capital tracker forecasts, set out above. However, as explained in Decision 3100-D01-2015,¹³⁶ the Commission is cognizant of the differences in purpose between the present decision and

¹³² Decision 3220-D01-2015: FortisAlberta Inc., 2013-2015 PBR Capital Tracker Application, Proceeding 3220, Application 1610570-1, March 5, 2015, paragraph 157.

¹³³ Decision 3267-D01-2015: ATCO Gas and Pipelines Ltd., 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast, Proceeding 3267, Application 1610634-1, March 19, 2015, paragraph 147.

¹³⁴ Paragraph 276 of EPCOR's 2015-2017 TFO tariff application, as quoted in Exhibit 20407-X0146, EDTI-AUC-2015JUN26-018(a).

¹³⁵ Exhibit 20407-X0237, EPCOR reply argument, paragraphs 51-53.

¹³⁶ Decision 3100-D01-2015, paragraph 148.

Decision 3539-D01-2015.¹³⁷ The purpose of Decision 3539-D01-2015 was to set rates for the EPCOR transmission function on a forecast basis, whereas the purpose of this decision is to establish forecast capital tracker amounts as part of a PBR plan for EPCOR's distribution function. Unlike EPCOR's TFO tariff approved revenue requirement, the 2016 and 2017 capital tracker forecasts approved in this application are subject to a full true-up following a prudence review of actual capital expenditures.

147. As also noted in Decision 3100-D01-2015,¹³⁸ under PBR, EPCOR's labour and non-labour costs are common to forecasting both O&M expenses and capital expenditures for projects that are fully funded under the I-X mechanism and those projects that require incremental funding through capital trackers. The Commission recognizes there remains an incentive for EPCOR to minimize these common costs in order to realize potential cost savings under PBR.

6.1.2 Capitalization of short-term incentive pay

148. In the application, EPCOR indicated that starting in 2014, it began including an allocation of short-term incentive pay (STIP Pool A costs) associated with staff that work on capital projects in the capital overhead pool. Historically, these costs were not capitalized but were instead, included in EPCOR's incentive compensation and incentive compensation – master overhead pool (MOP) operating costs categories. EPCOR indicated that it was proposing the change to be consistent with EPCOR Group's capital overhead policy, which states that incentive pay that is directly attributable to capital expenditures based on either time spent or headcount may be capitalized. EPCOR noted it made a similar proposal to capitalize STIP in its 2015-2017 TFO tariff application.¹³⁹

149. EPCOR clarified that its capital overhead policy has been in place since 2006, and was last revised in October 2011 to reflect the adoption of International Financial Reporting Standards (IFRS) by the company. EPCOR provided a copy of this capital overhead policy currently in effect,¹⁴⁰ and stated that after reviewing the EPCOR Group's capitalization and capital overhead policies in 2014, EPCOR determined that a portion of incentive pay is directly attributable to the construction of assets and is therefore appropriately capitalized. EPCOR maintained that its proposed capitalization of a portion of STIP is consistent with IFRS and its approved regulatory capital overhead policy and is consistent with Rule 026¹⁴¹ Section (2)(b), which requires utilities to adhere to the IFRS requirements for the treatment of overhead.¹⁴²

150. EPCOR indicated that in 2014, its distribution function capitalized \$1.03 million that would have otherwise been included as operating costs, of which \$0.63 million were allocated to proposed capital tracker projects, resulting in a 2014 K factor increase of \$0.02 million. The proposed capitalization of STIP costs resulted in an increase in forecast capital additions in 2016

¹³⁷ Decision 3539-D01-2015: EPCOR Distribution & Transmission Inc., 2015-2017 Transmission Facility Owner Tariff, Proceeding 3539, Application 1611027-1, October 21, 2015.

¹³⁸ Decision 3100-D01-2015, paragraph 146.

¹³⁹ Exhibit 20407-X0130.02, revised application, paragraph 160.

¹⁴⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-016 Attachment1, starting on PDF page 44.

¹⁴¹ Rule 026: *Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards*.

¹⁴² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-016(a), (c) and (e).

and 2017 of \$1.10 million in each year, resulting in a \$0.045 million increase to the total K factor amount applied for by EPCOR for each year.¹⁴³

151. In its evidence,¹⁴⁴ the CCA recommended that the Commission deny the inclusion of capitalized STIP costs in the K factor calculation for two reasons. The CCA explained that under PBR, the incentive pay was included in going-in rates as an O&M expense. By capitalizing these costs after the commencement of PBR, EPCOR is double-counting these costs, resulting in an increase in the overall revenue to the company that would not have occurred absent the accounting policy change. The CCA pointed out that in response to its IR, EPCOR confirmed it is not proposing any changes to the I-X portion of its rates as a result of STIP capitalization.¹⁴⁵ As such, the CCA stated this represents a double recovery of costs: the first recovery is in the I-X portion of rates, which are escalated annually, and the second recovery through the K factor.

152. In response to a Commission IR, the CCA further indicated that any change proposed by the company under PBR:

... needs to consider whether the proposed change impacts how revenue is calculated, now or in the future, as compared to the revenue calculated using the policies in existence for going-in rates. In other words, if changes are made they need to be transparent and optimally revenue neutral....

If the utility wants to adjust policies which are different than those that existed at the time of going in rates and the adjustments cause a rate impact, then in order for the change to be approved, it seems that the I-X escalated going-in rates should also be adjusted, such that there is no net impact. While this might be subject to a materiality test all such changes should be identified.¹⁴⁶

153. Further, the CCA contended that such a change must be disclosed in the annual PBR rate adjustment filing, in accordance with the provisions of paragraph 862 of Decision 2012-237. The CCA noted that it was not clear whether EPCOR advised the Commission and received Commission approval for this change. Paragraph 862 of Decision 2012-237 reads as follows:

862. The Commission directs each company to include in its annual PBR rate adjustment filing an attestation signed by a senior officer of the company as proposed by AltaGas. The senior officer attestation should include, as applicable, not only those items proposed by AltaGas, but also certifications on the accuracy, completeness and reasonableness of the numbers and assumptions included in the company's application. The required attestations and certifications by a senior officer of each company are as follows:

- confirm the reported ROE [return on equity] used to determine if a re-opener exists, either actual or weather normalized
- describe any changes in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts
- describe any changes in the depreciation parameters and associated impacts

¹⁴³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-016(f), Table EDTI-AUC-2015JUN26-016-2.

¹⁴⁴ Exhibit 20407-X0163, CCA evidence, paragraphs 19-20, as corrected in Exhibit 20407-X0222.

¹⁴⁵ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-011(b).

¹⁴⁶ Exhibit 20407-X0167, CCA-AUC-2015Aug 14-1(a).

- describe any changes in the allocation of shared services costs and associated impacts ...¹⁴⁷

154. In its argument, the CCA proposed to expand the wording in paragraph 862 of Decision 2012-237, to require disclosure of any accounting changes including, “calculation methods, changes in how expenditure was accounted for including bookkeeping, journal entries and other methods” as well as “any changes which result in differences between how the expenditure was accounted for up to December 31, 2012 and thereafter.”¹⁴⁸

155. EPCOR did not agree with the CCA’s view that capitalization of STIP would result in a double recovery of these costs. According to EPCOR, this is because the link between a company’s costs and revenues is severed under PBR.

MR. BARANIECKI: I don't think that's a fair characterization. I think that you -- that our revenues starting from our going-in year rates in 2012 under I minus X are just that. They're our revenues. And our costs are now separated from that, and there isn't a direct linkage anymore.

...
You're trying to make a direct link to what's going on in a particular year and not recognizing that there's a change -- or there's a disconnect now between revenues and costs. We are simply, in this case, applying our capitalization policy correctly and capitalizing something that should be capital. And it forms part of our capital expenditures, and, therefore, part of our capital additions and now is being -- by way of the capital tracker mechanism, some of that is going into a K factor.¹⁴⁹

156. During the hearing, Mr. Baraniecki also suggested that moving an allocation of STIP associated with staff that work on capital projects from the MOP operating costs categories to the capital overhead pool may be viewed as a type of allocative efficiency (which in this case refers to the mix of capital and O&M expenditures¹⁵⁰) that PBR is intended to promote.¹⁵¹

157. On the issue of disclosure of this change, EPCOR submitted that contrary to the assertion of the CCA, the inclusion of an allocation of STIP in the capital overhead pool was not a change in policy but merely a change in practice. EPCOR quoted in its rebuttal evidence portions of its argument from the EPCOR TFO 2015-2017 tariff application proceeding, where it maintained that:

... the capitalization of STIP in 2014 reflects the application of EDTI’s existing capitalization policy and is clearly the correct approach from an accounting perspective. The capitalization of STIP is not a change in accounting policy as suggested by the CCA, but is simply the application of EDTI’s existing Commission-approved capitalization policy to STIP costs. The capitalization of incentive pay is also consistent with the methods or procedures that other utilities within the province employ. It is clear that incentive pay that is directly attributable to capital expenditures based on either time spent or headcount should be capitalized. There has been no suggestion that it would be

¹⁴⁷ Decision 2012-237, paragraph 862.

¹⁴⁸ Exhibit 20407-X0234, CCA argument, paragraph 95.

¹⁴⁹ Transcript, Volume 1, page 86, line 2 to page 87, line 6 (Mr. Baraniecki).

¹⁵⁰ Transcript, Volume 3, page 415, lines 9-21 (Mr. Baraniecki).

¹⁵¹ Transcript, Volume 3, page 426, lines 9-16 (Mr. Baraniecki).

inappropriate from an accounting perspective to capitalize these costs. Therefore, while EDTI's decision to capitalize a portion of STIP differs from the treatment forecast, it reflected the correct treatment and was the correct application of EDTI's existing capitalization policy.¹⁵²

158. EPCOR further explained that it did not disclose its decision to capitalize STIP in either its 2014-2015 PBR capital tracker forecast application or its 2015 annual PBR rate adjustment filing because this change in practice had not been implemented until late 2014, after these filings had been made.¹⁵³ Hence, this proceeding was the first opportunity to identify this change to the Commission. EPCOR indicated it identified this change in the senior officer attestation included in its 2016 annual PBR rate adjustment filing, submitted on September 10, 2015.¹⁵⁴ Nevertheless, during the hearing, Mr. Baraniecki for EPCOR, stated he was not sure whether provisions of paragraph 862 of Decision 2012-237 apply to this change in practice regarding the treatment of STIP:

MR. BARANIECKI: I'm not sure that us thinking that this paragraph 862 applies is the rationale for doing it in our September application. We're not entirely sure whether this applies or not. I mean, you can read words in Bullet 4 or Row 2 in different ways. We're putting it the attestation as -- out of the abundance of caution. If the Commission thinks it should be there; we've put it in just in case, I guess.¹⁵⁵

159. Finally, EPCOR indicated that such a change in practice is not uncommon. In 2013, EPCOR began capitalizing inspection costs related to the installation of new meters and service connections. This change was accepted by the Commission in Decision 3100-D01-2015 in approving the costs for the Customer Revenue Metering – Growth & Life Cycle Replacements project.¹⁵⁶ Further, EPCOR pointed out that in Decision 2013-358,¹⁵⁷ the Commission approved the capitalization of ATCO Electric's variable pay program for employees working directly on capital projects.

160. In its argument, the CCA submitted that while the inclusion of capitalized inspection costs related to the installation of new meters and service connections was approved in Decision 3100-D01-2015, the issue of double counting was not raised by any party in the proceeding leading to that decision. The CCA stated that if this change in the treatment of inspection costs "had been identified upfront to the Commission, parties would have been aware of the context of the change and that it was clearly double counting and a change to going in rates."¹⁵⁸ In the CCA's view, this reaffirms the requirement that utilities must disclose any changes to the accounting methods before implementing such changes.¹⁵⁹ The UCA made a similar argument

¹⁵² Exhibit 20407-X0173, EPCOR rebuttal evidence, pages 29-30.

¹⁵³ Transcript, Volume 1, pages 191-193 (Mr. Chaudhary and Mr. Baraniecki).

¹⁵⁴ Exhibit 20407-X0237, EPCOR reply argument, paragraph 56.

¹⁵⁵ Transcript, Volume 1, page 194, lines 4-11 (Mr. Baraniecki).

¹⁵⁶ Decision 3100-D01-2015, paragraphs 509 and 517.

¹⁵⁷ Decision 2013-358: ATCO Electric Ltd. 2013-2014 Transmission General Tariff Application, Proceeding 1989, Application 1608610-1, September 24, 2013, paragraphs 67-68.

¹⁵⁸ Exhibit 20407-X0234, CCA argument, paragraph 91.

¹⁵⁹ Exhibit 20407-X0234, CCA argument, paragraphs 87-88.

and stated that the change in the treatment of meter inspection costs “was not specifically approved by the Commission in Decision 3100-D01-2015.”¹⁶⁰

161. Mr. Thygesen, for the CCA, expressed his view that, despite the Commission’s inclusion of capitalized inspection costs related to the installation of new meters and service connections in the capital expenditures for the Customer Revenue Metering – Growth & Life Cycle Replacements project in 2013, these costs should not be allowed for inclusion on a go-forward basis.¹⁶¹ In its argument, the CCA expressed its view that capitalization of these costs “should not be allowed for 2016 and 2017 now that the full implication of the double counting and change to going-in rates has been understood.”¹⁶²

162. In its argument, the UCA shared the CCA’s concern that capitalizing STIP would result in a double recovery of these costs. The UCA also took issue with EPCOR’s characterization of the proposed change of STIP costs from O&M to capital costs as a productivity gain arising from allocative efficiency. The UCA submitted that EPCOR should be directed to remove any capitalized STIP costs embedded in its capital tracker projects, for both the 2014 true-up and 2016-2017 forecast until the end of the current PBR term.¹⁶³

163. The UCA noted that a change to the treatment of STIP could be implemented at the time of a rebasing so as to avoid double-counting:

If EDTI wishes to make this change at the time of re-basing and concurrently remove the appropriate portion of STIP costs from the O & M component of its base rates, that would eliminate the concern that it was double counting dollars, and that customers are paying for some portions of the short term incentive pay twice. PBR was not intended to allow utilities to double charge customers.¹⁶⁴

164. In its argument and reply, the CCA expressed a similar concern and submitted that capitalization of STIP does not represent allocative efficiency. The CCA stated that “PBR should not allow utilities to increase profits simply through bookkeeping entries as opposed to genuine productivity increases.”¹⁶⁵

Commission findings

165. Paragraph 862 of Decision 2012-237 requires that EPCOR provide in its annual PBR rate adjustment filings an attestation signed by a senior officer of the company, describing, among other matters, “any changes in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts.” Paragraph 862 only requires disclosure of such changes, and leaves the decision on whether to allow or deny any such changes to the Commission’s discretion when considering the specific circumstances of each

¹⁶⁰ Exhibit 20407-X0236, UCA reply argument, paragraph 9.

¹⁶¹ Transcript, Volume 5, page 869, lines 9-14 (Mr. Thygesen).

¹⁶² Exhibit 20407-X0234, CCA argument, paragraph 93.

¹⁶³ Exhibit 20407-X0232, UCA argument, paragraph 67.

¹⁶⁴ Exhibit 20407-X0232, UCA argument, paragraph 70.

¹⁶⁵ Exhibit 20407-X0234, CCA argument, paragraph 72.

particular change. In Decision 20821-D01-2015, the Commission indicated it will make a determination on this matter in the present decision.¹⁶⁶

166. There are two issues before the Commission in this proceeding concerning the proposed change in the allocation of STIP Pool A costs associated with staff that work on capital projects from MOP operating cost categories to the capital overhead pool. The first issue relates to whether the disclosure requirements in paragraph 862 of Decision 2012-237 apply to the proposed change and, if so, whether EPCOR complied with these requirements. The second issue is whether the proposed inclusion of capitalized STIP in the 2014 to 2017 capital expenditures associated with projects proposed for capital tracker treatment, is reasonable. These issues are considered below.

Disclosure requirements

167. During the hearing, Mr. Baraniecki for EPCOR stated he was not sure whether provisions of paragraph 862 of Decision 2012-237 apply to this change in practice regarding the treatment of STIP.¹⁶⁷ As the CCA pointed out, EPCOR also did not include the disclosure of the change in the treatment of inspection costs for the Customer Revenue Metering – Growth & Life Cycle Replacements project in its senior officer attestation in any of the prior annual PBR adjustment filings.¹⁶⁸

168. The Commission agrees with the view of the CCA¹⁶⁹ that changes of this type, when costs are moved from O&M to capital cost categories represent a change “in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts.” Therefore, the Commission finds that changes of this type should be disclosed under the provisions of paragraph 862 of Decision 2012-237.

169. The Commission considers that in the circumstances where a company is not certain whether the provisions of paragraph 862 of Decision 2012-237 apply to a contemplated change to accounting methods, the company should err on the side of caution and make a disclosure in its senior officer attestation as part of the annual PBR rate adjustment filing regardless of whether the change represents “a change in accounting policy” or a change in accounting practice, even when the change is to effect “the application of EDTI’s existing Commission-approved capitalization policy to STIP costs.”¹⁷⁰ The Commission directs EPCOR to follow this approach in its future applications related to PBR and capital trackers.

170. Nevertheless, the Commission accepts EPCOR’s explanation that, because the decision to capitalize STIP had not been implemented until after late 2014,¹⁷¹ the company could not have included the disclosure of this change in its 2015 annual PBR rate adjustment filing, which was due on September 10, 2014. This statement is consistent with the November 25, 2014 filing date of EPCOR’s 2015-2017 TFO tariff application,¹⁷² where the company requested a similar change to the treatment of STIP. EPCOR identified this change to the Commission in the present capital

¹⁶⁶ Decision 20821-D01-2015, paragraph 68.

¹⁶⁷ Transcript, Volume 1, page 194, lines 4-11 (Mr. Baraniecki).

¹⁶⁸ Exhibit 20407-X0234, CCA argument, paragraph 88.

¹⁶⁹ Exhibit 20407-X0234, CCA argument, paragraphs 81-85.

¹⁷⁰ Exhibit 20407-X0233, EPCOR argument, paragraph 58.

¹⁷¹ Transcript, Volume 1, page 193, lines 7-12 (Mr. Baraniecki).

¹⁷² Proceeding 3539, EDTI 2015-2017 Transmission Facility Owner Tariff, filed November 25, 2014.

tracker application, filed in May 2015. EPCOR also identified this change in the senior officer attestation included in its 2016 annual PBR rate adjustment filing, as noted in Decision 20821-D01-2015.¹⁷³ Therefore, the Commission considers that EPCOR has complied with the requirements of paragraph 862 of Decision 2012-237.

171. The Commission does not agree with the CCA¹⁷⁴ that a revision to the requirements of the senior officer attestation described in paragraph 862 of Decision 2012-237 is needed. The Commission considers that the language in paragraph 862 of Decision 2012-237 is sufficiently comprehensive to encompass the nature of the accounting changes made by EPCOR.

Reasonableness of the proposed inclusion of capitalized STIP in the 2014-2017 capital expenditures associated with projects proposed for capital tracker treatment

172. While the Commission has evaluated all arguments in considering EPCOR's proposal to capitalize a portion of STIP Pool A costs, it considers that the findings in respect of a single issue, the possible double-counting of STIP Pool A costs and therefore, the reasonability of including these costs in the revenue requirement of a capital tracker, will be determinative of the matter.

173. The Commission generally agrees with EPCOR¹⁷⁵ that under the PBR framework based on the I-X mechanism, as approved in Decision 2012-237, a utility's revenues are no longer linked to its costs. However, as set out in Section 2.1 of this decision, the PBR rates formula approved for EPCOR in Decision 2012-237 provides that the company's distribution rates for each year may also include adjustments to fund necessary qualifying capital expenditures (K factor), adjustments for certain flow-through costs that should be directly recovered from customers or refunded to them (Y factor), and adjustments to account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor). It is through these adjustments outside of the I-X mechanism, largely done on a cost-of-service basis, that some connection between the company's rates and its costs is retained under the existing PBR plan.

174. During the hearing, in exchange with the Commission, Mr. Baraniecki acknowledged that, under the existing PBR regime, which includes an opportunity for capital trackers, there could be an incentive for a company to shift costs from that part of the regime which is governed by the I-X mechanism to that part of the regime which is governed by capital trackers, although there are mechanisms in place that dissuade that incentive.¹⁷⁶ At the same time, Mr. Baraniecki advised that capitalization of STIP was not an example of an intentional shifting of costs in order to take advantage of the capital tracker mechanism, because this change was consistent with EPCOR's capitalization policy that was implemented in 2011, prior to the introduction of PBR.¹⁷⁷

¹⁷³ Decision 20821-D01-2015, paragraphs 64 and 68.

¹⁷⁴ Exhibit 20407-X0234, CCA argument, paragraph 95.

¹⁷⁵ Transcript, Volume 1, page 86, line 2 to page 87, line 6 (Mr. Baraniecki).

¹⁷⁶ Transcript, Volume 3, page 419, line 14 to page 420, line 5 (Mr. Baraniecki).

¹⁷⁷ Transcript, Volume 3, page 420, lines 12-22 (Mr. Baraniecki).

175. However, the Commission agrees with the CCA's view,¹⁷⁸ supported by the UCA,¹⁷⁹ that the proposed capitalization of STIP, whether it was intended to take advantage of the capital tracker mechanism or not, would result in a double-counting of these costs under the existing PBR framework. The double-counting will occur because the I-X mechanism already provides funding to account for this type of cost, as EPCOR's going-in rates incorporated the full amount of STIP costs which were classified as an O&M expense in 2012.¹⁸⁰ The inclusion of the STIP Pool A costs in the capital overhead pool and the resulting recovery of these amounts through a K factor outside of the I-X component of the PBR rates formula would provide funding to account for a portion of these costs again.

176. With respect to the Commission's approval of ATCO Electric's variable pay program for employees working directly on capital projects in Decision 2013-358,¹⁸¹ referenced by EPCOR, this approval was given under cost-of-service regulation and on a prospective (i.e., forecast) basis,¹⁸² and thus, ensured that approved costs were not being recovered twice through customer rates.

177. The Commission recognizes that the proposed capitalization of STIP appears to be consistent with acceptable accounting practices under IFRS. However, as set out in paragraph 594 of Decision 2012-237, in order for a capital cost to qualify for capital tracker treatment, the company must demonstrate that there is no double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded through the I-X mechanism. Accordingly, having made the finding that double counting of a portion of STIP Pool A costs would occur, the Commission denies the inclusion of capitalized STIP in the costs of EPCOR's proposed capital tracker projects in the current PBR term. EPCOR is directed, in the compliance filing to this decision, to remove any capitalized STIP costs from the 2014 actual and 2016 and 2017 forecast capital expenditures associated with the projects or programs proposed for capital tracker treatment.

178. In Decision 3100-D01-2015 dealing with EPCOR's 2013 true-up and 2014-2015 forecast capital tracker application, the Commission accepted EPCOR's capitalized inspection costs related to the installation of new meters and service connections, in the amount of a \$0.95 million,¹⁸³ in approving the actual costs for the Customer Revenue Metering – Growth & Life Cycle Replacements project in 2013. However, as the CCA and the UCA pointed out, the issue of double-counting was not raised in the proceedings leading to Decision 3100-D01-2015.

179. The double-counting issue was raised in this proceeding by the CCA in respect of this component of the Customer Revenue Metering – Growth & Life Cycle Replacements project costs, on a go-forward basis.¹⁸⁴ The Commission has considered the CCA evidence in this proceeding and finds that the above reasoning that the proposed capitalization of STIP would result in a double-counting of these costs under the existing PBR framework also applies to the capitalized inspection costs related to the installation of new meters and service connections. The

¹⁷⁸ Exhibit 20407-X0163, CCA evidence, paragraphs 19-20, as corrected in Exhibit 20407-X0222.

¹⁷⁹ Exhibit 20407-X0232, UCA argument, paragraph 67.

¹⁸⁰ Transcript, Volume 1, page 88, lines 12-18 (Mr. Baraniecki).

¹⁸¹ Decision 2013-358, paragraphs 67-68.

¹⁸² Decision 2013-358, paragraph 64.

¹⁸³ Decision 3100-D01-2015, paragraph 509.

¹⁸⁴ Exhibit 20407-X0234, CCA argument, paragraph 93.

double-counting will occur because the I-X mechanism already provides funding to account for this type of cost, as EPCOR's going-in rates incorporated the full amount of inspection costs related to the installation of new meters and service connections which were classified as an O&M expense in 2012. Capitalizing inspection costs related to the installation of new meters and service connections and the resulting recovery of these amounts through a K factor outside of the I-X component of the PBR rates formula would provide funding to account for a portion of these costs again. As the CCA pointed out,¹⁸⁵ this new information underscores the need for the timely disclosure of such intended changes "in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts," as required in paragraph 862 of Decision 2012-237.

180. The Commission agrees with the concerns raised by the CCA with respect to double counting of inspection costs in respect of the 2016 and 2017 years and accepts the CCA's recommendation¹⁸⁶ to deny the inclusion of capitalized inspection costs related to the installation of new meters and service connections in the costs of the Customer Revenue Metering – Growth & Life Cycle Replacements project on a go-forward basis for 2016 and 2017. EPCOR is directed, in the compliance filing to this decision, to remove any capitalized inspection costs related to the installation of new meters and service connections costs from the 2016 and 2017 forecast capital expenditures associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project.

6.1.3 Affiliate transactions

181. In Decision 3558-D01-2015, which considered modifications to the minimum filing requirements for capital tracker applications, the Commission determined the identification of any affiliate-related costs included in the forecast or actual costs of a proposed capital tracker project or program to be useful in assessing those projects or programs. Accordingly, at paragraph 80 of Decision 3558-D01-2015, the Commission made the following direction:

80. ... the companies are directed to include in their business cases a summary of the services provided by or to an affiliate, the related costs and an explanation of how those amounts were determined.¹⁸⁷

182. To comply with this direction in the application, EPCOR detailed the services provided to or by its affiliates, including the costs of those services and the manner in which those costs were reflected in its capital tracker projects or programs. EPCOR provided the following table summarizing its affiliate services:

¹⁸⁵ Exhibit 20407-X0234, CCA argument, paragraph 88.

¹⁸⁶ Exhibit 20407-X0234, CCA argument, paragraph 93.

¹⁸⁷ Decision 3558-D01-2015, paragraph 80.

Table 5. EPCOR's affiliate services¹⁸⁸

Service	Affiliate
Information technology (IT) support	EPCOR Utilities Inc.
Engineering services for design and as-built drawings	EPCOR Technologies Inc.
Hydro-excavation services (hydrovac)	EPCOR Technologies Inc.
Soil & water dumping services (dewatering hydro-excavation trucks)	EPCOR Technologies Inc.
Pushing (smaller diameter pipe directional drilling)	EPCOR Technologies Inc.
Civil construction services for cable replacement	EPCOR Technologies Inc.
Cable pulling for underground customer service connections	EPCOR Technologies Inc.
Construction, maintenance and repair of security lighting systems	EPCOR Technologies Inc.

183. The provision of affiliate services to EPCOR is set out in separate service level agreements (SLA) for each of EPCOR Utilities Inc. (EUI) and EPCOR Technologies Inc. (ETECH). The SLA between EPCOR and EUI details work for IT software and hardware related to the OMS/DMS Life Cycle Replacement project, discussed in Section 6.2.7, and the IT Hardware Life Cycle Replacements and Additions Distribution project, discussed in Section 6.3.2. The SLA between EPCOR and ETECH are for contracted work on “an as available basis.”¹⁸⁹

184. For the OMS/DMS Life Cycle Replacement project, EUI issued the initial request for information on behalf of EPCOR Distribution and Transmission to gather information on industry OMS/DMS.¹⁹⁰ For the IT Hardware Life Cycle Replacements and Additions Distribution project, EUI's Information Services assessed the alternatives to replace the operating system for its servers, as part of life cycle replacement planning.¹⁹¹ EUI finished its assessment of the alternatives and allocated the distribution project costs to EPCOR for the IT Hardware Life Cycle Replacements and Additions Distribution project.

185. EPCOR explained that for capital tracker projects, ETECH is only involved after the determination has been made that a third party is needed to complete the work. An external party is typically required when EPCOR does not have the internal resources or specialized equipment to complete the work in a cost-effective manner or to manage workflow peaks.¹⁹² EPCOR outlined the process by which it ensures the affiliate services provided are consistent with competitive market rates available from non-affiliates for each of the ETECH services listed in Table 5.

186. For the engineering services for design and as-built drawings, ETECH's engineering rates are compared to the successful engineering consultant bid rates from a 2012 request for proposals (RFP), which are now subject to a master service agreement (MSA), to ensure they are

¹⁸⁸ Exhibit 20407-X0130.02, revised application, paragraph 126.

¹⁸⁹ Exhibit 20407-X0130.02, revised application, paragraphs 127-130.

¹⁹⁰ Exhibit 20407-X0083, Appendix A-18, paragraph 7.

¹⁹¹ Exhibit 20407-X0073, Appendix A-23, paragraph 19.

¹⁹² Exhibit 20407-X0130.02, revised application, paragraph 131.

consistent. EPCOR reviewed the MSA engineering rates in 2014 to ensure they were still reflective of the competitive market rates in Alberta.¹⁹³

187. In regards to hydrovac services, EPCOR explained it maintains a limited number of units to carry out a normal level of work, and when it does not have sufficient hydrovac units to complete the required volume of work, ETECH is contacted. ETECH provides the hydrovac service either using its own units if they are available and, if not, ETECH utilizes one of the 14 contractors with whom EPCOR has an MSA to complete the hydrovac work. If ETECH's own unit performs the work, EPCOR compares ETECH's rates to the rates of the 14 contractors selected through an RFP and signed to an MSA.¹⁹⁴

188. EPCOR also explained that when ETECH arranges for hydrovac services it is also responsible for the proper disposal of the soil. The soil and water dewatering site used is operated by ETECH in south Edmonton and EPCOR minimizes the costs of its own hydrovac units by using ETECH's site when working in the south of Edmonton, rather than its own north Edmonton site. EPCOR compares the rates for ETECH's soil and water dumping services to other services in the Edmonton area to ensure they are competitive.¹⁹⁵

189. Furthermore, EPCOR explained in an IR response to the Commission, that while ETECH manages the hydrovac dispatching for EPCOR, the costs are minimized by sending the hydrovac with the lowest cost option, whether it is an ETECH hydrovac unit or that of a pre-approved contractor.¹⁹⁶

190. For directional drilling, ETECH coordinates the contractors with which EPCOR has negotiated MSAs, as neither EPCOR nor ETECH have the speciality crews required to complete the work. For the contractors managed by ETECH, EPCOR compares the rates to the competitive rates bid in a 2011 RFP for contractors that were signed to MSAs.¹⁹⁷ Similarly, when ETECH is used by EPCOR for construction services related to cable replacement, the rates are compared to those of five contractors selected through a 2011 RFP and signed to MSAs.¹⁹⁸ For cable pulling for underground service connections, EPCOR compares the ETECH rates to its internal rate.¹⁹⁹

191. The last affiliate service in Table 5 that EPCOR contracts ETECH for is the construction and maintenance of security lighting systems. EPCOR enlisted ETECH to provide its security lighting services given that it provides similar services to the City of Edmonton.

192. EPCOR explained that affiliate services are used for work on both its operating and capital projects, including capital tracker and non-capital tracker projects. EPCOR provided a table showing the breakdown of affiliate costs for its capital tracker projects on an actual basis in

¹⁹³ Exhibit 20407-X0130.02, revised application, paragraph 133.

¹⁹⁴ Exhibit 20407-X0130.02, revised application, paragraphs 134-135.

¹⁹⁵ Exhibit 20407-X0130.02, revised application, paragraphs 136-138.

¹⁹⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-012(a).

¹⁹⁷ Exhibit 20407-X0130.02, revised application, paragraphs 139-140.

¹⁹⁸ Exhibit 20407-X0130.02, revised application, paragraph 141.

¹⁹⁹ Exhibit 20407-X0130.02, revised application, paragraph 142.

2014 and forecast basis for 2016 and 2017. In response to a CCA IR, EPCOR also provided the following 2015 forecast.²⁰⁰

Table 6. EPCOR actual and forecast affiliate services costs²⁰¹

Capital tracker project	2014 actual	2015 forecast	2016 forecast	2017 forecast
	(\$ million)			
EPCOR Utilities affiliate transactions				
OMS-DMS Lifecycle Replacement		1.21	0.10	
IT Hardware Life Cycle Replacements and Additions Distribution		0.04	0.07	0.03
Total EPCOR Utilities Inc.		1.25	0.17	0.03
EPCOR Technologies Inc. affiliate transactions				
Capitalized Aerial System Damage	0.09			
Capitalized Underground System Damage	0.25			
LRT Distribution System Relocation	0.21			
Walterdale Bridge	0.02			
Franchise Agreement Driven Relocations and Conversions	0.25	0.17	0.22	0.22
Life Cycle Replacement and Extension of Underground Distribution Cable	1.19	0.85	0.93	0.95
New 15kV and 25kV Circuit Additions	0.14	0.00	0.10	0.03
New Underground and Aerial Service Connections for Commercial, Industrial, Multifamily and Misc. Customers	1.43	0.58	1.01	1.14
New UG Cable and Aerial Line Reconfigurations and Extensions to Meet Customer Growth	0.46	0.19	0.26	0.25
URD Servicing - Rebates, Acceptance Inspections and Terminations	0.77	0.33	0.25	0.36
Distribution Pole and Aerial Line Life Cycle Replacements		0.28	0.38	0.45
Aerial and Underground Distribution Transformers - New Services and Life Cycle Replacement	0.02	0.03	0.03	0.03
UID Servicing - Rebates, Acceptance Inspections and Terminations	0.50	0.06	0.27	0.27
Replacement of Faulted Distribution PILC Cables	0.05	0.02	0.03	0.03
Street Light Service Connections and Security Lighting Addition and Capital Replacement		0.39	0.26	0.27
Switching Cubicle Life Cycle Replacement		0.06	0.10	0.10
Total EPCOR Technologies Inc.	5.38	2.96	3.85	4.10
Total	5.38	4.21	4.01	4.14

193. EPCOR explained how it forecasts amounts for its affiliate transactions related to capital projects:

In general, EDTI forecasts costs arising from work forecast to be done by an affiliate for its capital projects using the budgeting/forecasting methodology employed for that

²⁰⁰ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-007.

²⁰¹ Exhibit 20407-X0130.02, revised application, tables 2.1.5.2-1 and 2.1.5.3-1. The 2015 forecast numbers were provided in Exhibit 20407-X0154, EDTI-CCA-2015JUN26-007.

particular project. For example, if the forecasting methodology for a project, as described in the Business Case and Engineering Study, is based on the use of a three year normalized historical average, then the forecast affiliate costs for that project will also be based on the three year normalized historical average of actual costs of the work provided by the affiliate.²⁰²

194. In regards to minimizing the cost of all affiliate services, EPCOR confirmed that ETECH is used only when it will provide the overall lowest cost option among the contractors that have been pre-approved to complete the work.²⁰³

Commission findings

195. The Commission has reviewed EPCOR's disclosure of its affiliate transactions relating to its capital tracker projects in light of the direction given at paragraph 80 of Decision 3558-D01-2015. EPCOR detailed the related costs of affiliate transactions to its capital tracker projects in its application, project business cases and IR responses to the Commission. The Commission also notes that EPCOR confirmed it only uses an affiliate such as ETECH to complete work when the cost to do so is the lowest among all pre-approved contractors.²⁰⁴

196. Accordingly, the Commission finds that EPCOR has complied with the direction set out at paragraph 80 of Decision 3558-D01-2015.

6.1.4 Controls and accountability

197. At paragraph 152 of Decision 3100-D01-2015, the Commission stated:

152. The Commission considers that formal project management policies and procedures are necessary to ensure the Commission understands that the scope, level, timing and costs of forecast capital projects are reasonable and actual costs are prudently incurred. The Commission directs EDTI to describe fully its formal project management policies and procedures in its next capital tracker application.

198. To comply with this direction, in the application, EPCOR described its project management policies and procedures used to assist EPCOR in completing its capital projects safely, on time and in a cost effective manner. EPCOR detailed the following policies and procedures relating to its project management: initiation, budget preparation, budget approval, planning, design and procurement, execution, variance monitoring and cost control, performance expectations and management and continuous improvement.

199. EPCOR explained that projects are initiated as the need arises or as part of the annual capital budgeting cycle, and are grouped as either growth projects, life cycle replacement projects, or performance improvement projects. Recurring projects are evaluated according to existing business cases or engineering studies, whereas new projects require a cost review and justification prior to approval by EPCOR senior managers. Projects are assessed according to

²⁰² Exhibit 20407-X0130.02, revised application, paragraph 128.

²⁰³ Exhibit 20407-X0233, EDTI argument, paragraph 52.

²⁰⁴ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-012(a).

whether they are required or can be deferred, and alternatives are considered to determine which are least cost and reasonable solutions.²⁰⁵

200. At the project budget preparation stage, a bottom up budget forecast is prepared using the known scope, available resources and equipment, historical projects costs, and average unit rates to reflect the most cost effective solution that meets the requirements of the project. EPCOR's budget preparation uses its capital budgeting tool to prepare expenditure estimates. Labour costs are forecast based on a man-hour estimation using the hourly rates in EPCOR's collective bargaining agreements. Engineering costs are also based on a man-hour estimation using an average engineering salary rate. For materials and contractors, EPCOR creates a forecast using current cost and the scope of the project, while also considering historical costs from similar projects and information from suppliers and contractors.

201. The capital costs for a project in 2016 or 2017 are forecast in 2015 dollars, and then inflated using the escalation factors discussed in Section 6.1.1 of this decision. Once the costs have been escalated, employee fringe benefits are then applied according to the rates discussed in Section 6.1.1 of this decision. The final step is to apply the capital overhead amounts to the capital projects according to the overhead rates, also detailed in Section 6.1.1. If EPCOR does not have enough information at the time of budget preparation, a forecast method such as a historical three-year average is utilized.

202. In regards to staffing internal and contractor crews, EPCOR indicated it maintains a prudent level of internal employees to complete a normal core level of work, which is determined by its budget and historical amounts of work completed in prior years. External contractor crews are used to complete peak levels of work that are higher than normal work levels. EPCOR also uses contractor crews to complete specialized work where it would be more expensive to maintain internal staff to complete the work.²⁰⁶

203. When selecting external contractors or consultants to carry out work, EPCOR uses a roster of external parties that have been pre-qualified by both EPCOR and its parent company, EUI. The pre-qualification process involves a competitive procurement process such as an RFP, and then successful contractors are signed to an MSA for three years.²⁰⁷

204. For purchasing materials, EPCOR uses industry standard distribution system equipment purchased using competitive bid processes for materials with a cost over \$75,000.²⁰⁸ Contracts are then signed for three- to five-year terms. If the purchase is less than \$75,000, EPCOR selects a vendor that it has used previously and that is able to meet the schedule and specification needs. The price from that vendor is compared to historical pricing to ensure it is competitive.²⁰⁹

205. At the budget approval stage, a series of meetings are held to determine whether EPCOR's internal employees can meet the core level of work required and whether each cost component of the budget was developed to help minimize costs. After the budget for individual

²⁰⁵ Exhibit 20407-X0130.02, revised application, paragraphs 44-47.

²⁰⁶ Exhibit 20407-X0130.02, revised application, paragraphs 66-70.

²⁰⁷ Exhibit 20407-X0130.02, revised application, paragraphs 74-77.

²⁰⁸ Exhibit 20407-X0130.02, revised application, paragraph 89.

²⁰⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-007(b).

projects has been renewed, the final distribution budget requires approval from the financial review council, followed by the board of directors.²¹⁰

206. Following the approval of the annual capital budget, EPCOR's planning group produces an annual project plan with quarterly targets for all capital projects. In developing the annual project plan, EPCOR considers factors such as safety and environmental risks, system reliability requirements, the requirements of external parties, and opportunities for coordination of the work with other construction activities.²¹¹

207. The technical design of projects is completed by EPCOR's engineers, with more complex projects being reviewed with operations and construction groups, as well as contractors. During the design process, EPCOR aims to minimize costs through alternative designs or constructions methods, as well as reusing existing infrastructure. EPCOR's purchasing group is responsible for the procurement of project materials and minimizes costs through bulk ordering and having supplies in stock before a project begins.²¹²

208. The monitoring of projects being completed by internal crews is done by EPCOR's foremen, whereas contractor work is monitored by EPCOR's contractor inspectors. EPCOR indicated that project and variance managers are responsible for ensuring projects are finished on time, and in efficient and cost effective ways.²¹³

209. To monitor variances and control project costs, EPCOR stated it has a number of review and approval procedures in place. Project costs are reviewed monthly and variances from the approved budget to current or year-end forecasts are identified. At this time, any potential cost mitigation is undertaken and any variances above the approved costs are required to be justified.²¹⁴ Variances in excess of 10 per cent of the approved year-to-date budget require a documented formal explanation, and are then discussed with EPCOR's senior managers and directors. When a project has an increased cost of \$25,000 and 20 per cent as compared to the approved year-end budget, a supplemental justification sheet is completed by the variance manager.²¹⁵ EPCOR confirmed that both the \$25,000 and 20 per cent thresholds have to be met in order for a supplemental justification sheet to be required.²¹⁶ The justification sheet explains the drivers of the increased cost, activities taken to minimize the increase, and further actions that could be taken. The supplemental justification sheet is then approved by managers, directors, the distribution controller and an EPCOR senior vice-president, before the additional cost can be incurred.²¹⁷

²¹⁰ Exhibit 20407-X0130.02, revised application, paragraphs 91-92.

²¹¹ Exhibit 20407-X0130.02, revised application, paragraph 93.

²¹² Exhibit 20407-X0130.02, revised application, paragraphs 96-100.

²¹³ Exhibit 20407-X0130.02, revised application, paragraphs 103-105.

²¹⁴ Exhibit 20407-X0130.02, revised application, paragraph 108.

²¹⁵ Exhibit 20407-X0130.02, revised application, paragraphs 109-112.

²¹⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-009(f).

²¹⁷ Exhibit 20407-X0130.02, revised application, paragraphs 109-112.

210. In addition, executive approvals from EPCOR's chief executive officer, chief financial officer, and senior vice-presidents are required for project budget increases greater than \$2 million and a forecast variance exceeding 20 per cent.²¹⁸

211. EPCOR also explained that performance metrics related to the completion of capital projects are reported and monitored monthly and the metrics directly affect employee incentive pay, as well as advancement within EPCOR.²¹⁹ Managers, out of scope employees and foremen take part in the Aligning Performance for Results process, whereby those employees' performances are evaluated and rated at year end. The evaluation is based on expectations for project design, reporting, management, and execution, as well as measurable targets for cost control, adherence to schedules and achieving business unit targets. This year-end rating affects the annual incentive compensation employees receives, and if employees continue to fail to meet the identified goals and expectations, their employment status may be affected.²²⁰

212. There are also annual capital asset targets that are included in EPCOR's business goals, such as distribution poles replaced, underground cable tested, injected, and replaced, customer energization time, and capital expenditures as compared to the annual budget. The asset targets are also considered in EPCOR's annual employee performance reviews.²²¹

213. EPCOR further indicated that in 2014 and 2015, the company undertook a review of distribution project management and practices with the aim of improving the procedures in place to help ensure cost effective and efficient work. EPCOR expected that the improvements identified in this review will be implemented by the end of 2015.²²²

214. During the hearing, the issue of EPCOR's internal quality control procedures was brought up in light of the identified errors and revisions to the originally filed revenue requirement calculations and K factor amounts, as part of EPCOR's accounting test model. Mr. Baraniecki discussed EPCOR's internal quality control procedures and how improvements are made to minimize errors in EPCOR's models. Specifically, Mr. Baraniecki explained in a conversation with Commission counsel, that EPCOR is moving towards formalizing its process for reviewing submissions:

Q. And then as a result of finding these types of human error models, have you made any policy changes or internal process changes that would be implemented on a go-forward basis that might help catch these things before they become submitted?

A. MR. BARANIECKI: As of today, we haven't put in anything formally in place, but Mr. Zurek and myself have been talking about the processes that we're using and ways to approve these processes and put more rigor on it. And granted, you know, it was just this summer that we've discovered these things or I guess back into about May -- well, whatever the preparation of the transmission hearing was. And we fully intend to put more formal things in place to the extent that we can discover them and determine them that we think will make it a better and easier process and more robust. That being said, on

²¹⁸ Exhibit 20407-X0130.02, revised application, paragraph 113.

²¹⁹ Exhibit 20407-X0130.02, revised application, paragraph 115.

²²⁰ Exhibit 20407-X0130.02, revised application, paragraph 122.

²²¹ Exhibit 20407-X0130.02, revised application, paragraphs 117-120.

²²² Exhibit 20407-X0130.02, revised application, paragraphs 123-124.

a relative scale, I mean, we don't feel like we have a significant number of errors. And we are very -- we are confident that we've caught hopefully all of the them here.²²³

215. EPCOR indicated that it would explain these policy and process improvements in its next capital tracker application.²²⁴

216. The CCA and the UCA made no submissions with respect to EPCOR's controls and accountability processes and procedures.

Commission findings

217. The Commission has reviewed EPCOR's project management controls and accountability policies and procedures in light of the directions set out at paragraph 152 of Decision 3100-D01-2015. EPCOR provided a helpful explanation of its controls and accountability procedures with respect to the planning, design, execution and review of its capital projects, in order to aid in the Commission's understanding of whether the scope, level, timing and costs of forecast capital projects are reasonable and the actual costs are prudently incurred. The Commission finds that EPCOR has complied with the direction set out at paragraph 152 of Decision 3100-D01-2015. The Commission directs EPCOR to confirm that these policies and procedures continue to be in place and to advise the Commission of improvements and modifications to these policies and procedures in future capital tracker applications.

6.1.5 Asset usage fees

218. In its August 24, 2015 letter that was submitted with its revised application, EPCOR explained that it had mistakenly omitted the inclusion of asset usage fees from its capital tracker model and K factor calculations. The result of the omission was the potential double recovery of costs related to the OMS/DMS project and the Work Centre Redevelopment project.²²⁵

219. An AUF occurs when one of EPCOR's functions (i.e., the distribution function or the transmission function) pays capital costs to the other function for the joint use of an asset owned by the function that receives the AUF. The potential for double counting arises if EPCOR Distribution is applying for a K factor amount for a project, as determined by the accounting test, while also receiving an AUF from EPCOR Transmission that is intended to, in part, provide funding to EPCOR Distribution for EPCOR Transmission's involvement in the project.

220. In its August 24, 2015 letter, EPCOR explained that under PBR, the AUFs should be treated differently, depending on when the AUF was first established. Specifically, EPCOR proposed that AUFs that were in place prior to 2013 should not be identified separately in EPCOR's accounting test model provided in the updated application given that those AUFs are subject to the I-X mechanism. EPCOR explained:

The double counting of AUFs error only relates to new AUFs that have been established since the start of PBR in 2013, and does not affect AUFs that were in place prior to 2013. This is because AUFs that existed prior to 2013 have been included in EDTI's

²²³ Transcript, Volume 1, page 132, lines 23-25 and page 133, lines 1-17 (Mr. Baraniecki).

²²⁴ Transcript, Volume 1, page 133, lines 22-23 (Mr. Baraniecki).

²²⁵ Exhibit 20407-X0131, EPCOR letter, August 24, 2015, paragraph 4.

distribution function base rates, reducing the revenue requirement recovered from customers by the AUF amount in each year starting in 2013.²²⁶

221. During the hearing, Mr. Zurek, for EPCOR, confirmed that any AUFs in place prior to 2013 are an offset to the revenue requirement included in going-in rates, which are adjusted annually by the I-X mechanism.²²⁷

222. EPCOR proposed a different treatment under PBR for AUFs that were implemented after going-in rates were established. Given that any new AUF implemented after the start of PBR is intended to provide funding for the joint use of an asset or joint involvement in a project which was not included in going-in rates, EPCOR indicated that an adjustment outside of the I-X mechanism is required, provided capital tracker treatment is sought for that asset or project. EPCOR further clarified its position on the treatment of AUFs established after the start of the PBR term:

AUFs that are new since the start of PBR in 2013, are not reflected in EDTI's distribution function base rates and, accordingly, no reduction in revenue requirement recovered from customers occurs, giving rise to the double recovery problem. Specifically, EDTI's capital tracker model calculates revenue incurred based on total forecast distribution function rate base resulting in full recovery of capital costs through EDTI's distribution function rates (base rates plus K factor). At the same time, however, EDTI recovers AUF paid by EDTI's transmission function to EDTI's distribution function through its transmission function TFO Tariff Applications. Reduction of the K factor amount by the AUF amount for projects with AUF that were established since the start of PBR in 2013 eliminates the double counting of revenue. No new AUFs were established in 2013 or 2014.²²⁸

223. In its revised application, EPCOR included AUFs for two of its applied-for capital tracker projects in 2016 and 2017, the OMS/DMS and the Work Centre Redevelopment projects. Both of these projects involve assets that are owned and operated by EPCOR Distribution, but are also used by EPCOR Transmission. Each AUF paid by one EPCOR function to the other has a unique allocation factor which determines the portion of capital costs that are included in the AUF. Once the allocation factor has been determined, it is applied to a specific "cost pool" for the joint-use asset or project to calculate the AUF amount for each of EPCOR Distribution and Transmission.

224. EPCOR provided, along with its revised application, a description of its allocation factors, the method for calculating the allocations, and the resulting AUF amounts. For the OMS/DMS capital tracker project, there is one new AUF for 2016 and 2017, which specifically relates to the outage management system that co-ordinates electrical outages and restoration activities for EPCOR. The allocation factor is calculated as a ratio of the average annual number of EPCOR Transmission switching order steps from 2011 to 2013 to the total average annual switching steps for EPCOR's total system, based on the same three year period. EPCOR

²²⁶ Exhibit 20407-X0131, EPCOR letter, August 24, 2015, paragraph 8.

²²⁷ Transcript, Volume 1, page 149, lines 19-25 (Mr. Zurek).

²²⁸ Exhibit 20407-X0131, EPCOR letter, August 24, 2015, paragraph 9.

explained that this allocation factor is calculated using the same method employed to determine the share of operational costs for the OMS system for EPCOR Distribution and Transmission.²²⁹

225. The OMS allocation factor is then applied to the cost pool made up of the annual depreciation and return on rate base for the asset. Given that EPCOR estimates the OMS portion of the OMS/DMS project will be completed and in service in 2017, the forecast AUF is for 2017 only.²³⁰

226. At the hearing, Mr. Baraniecki explained that the allocation factor for the OMS AUF is calculated using a new method because there was no current allocation factor that closely matches the use of the OMS system.²³¹ In addition, using switching order steps as the allocator is a better approach than using an allocator based on the amount of system monitoring for each of Transmission and Distribution that occurs in the OMS/DMS system. The reason is that monitoring occurs based on physical assets, of which transmission has a smaller number.²³² Switching order steps measure the amount of work the OMS/DMS systems do for each function.²³³

227. For the Work Centre Redevelopment project, there are three new AUFs paid by EPCOR's transmission function to its distribution function for 2015 to 2017. The first relates to the land acquired as part of the Work Centre Redevelopment project. The second AUF is for the building expansion costs related to the project and the third AUF is for the fixtures and fittings associated with the project. All three AUFs use the same allocation factor: a ratio of the forecast operating costs related to EPCOR's service centres associated with the transmission function to the total forecast operating costs for EPCOR's service centres. The operating costs in the allocation factor are forecast for the period of 2015 to 2017.²³⁴

228. The AUF for the land portion of the project is applied to a cost pool that is made up of the return on rate base for the asset account. For the building AUF and the fixtures and fittings AUF, the allocation factors are applied to cost pools composed of the annual depreciation and return on rate based for the respective asset accounts.²³⁵ The method for calculating the allocation factors for all three AUFs related to the Work Centre Redevelopment project are consistent with the methods used to calculate the respective General Plant Land and Buildings AUFs, which are included in EPCOR's going-in rates.

229. The following table summarizes the applied-for forecast K factor amounts for the OMS/DMS project and the Work Centre Redevelopment project, net of the proposed AUFs:

²²⁹ Exhibit 20407-X0175, Summary of Asset Usage Fees.

²³⁰ Exhibit 20407-X0175, Summary of Asset Usage Fees.

²³¹ Transcript, Volume 1, page 160, lines 10-22 (Mr. Baraniecki).

²³² Transcript, Volume 1, page 161, lines 7-13 (Mr. Baraniecki).

²³³ Transcript, Volume 1, page 162, lines 11-13 (Mr. Baraniecki).

²³⁴ Exhibit 20407-X0175, Summary of Asset Usage Fees.

²³⁵ Exhibit 20407-X0175, Summary of Asset Usage Fees.

Table 7. EPCOR's 2016 and 2017 forecast asset usage fees and net K factors²³⁶

Description	2016	2017
	(\$ million)	
OMS/DMS total K factor	1.44	1.83
OMS/DMS AUF	N/A	0.04
OMS/DMS net K factor	1.44	1.79
Work Centre Redevelopment project total K factor	1.67	4.20
Work Centre Redevelopment project total AUF	1.08	1.71
Work Centre Redevelopment project net K factor	0.59	2.49

230. EPCOR also provided the forecast AUF amount of \$0.31 million for the Work Centre Redevelopment project in 2015.²³⁷ EPCOR currently does not have a forecast K factor amount for 2015 for the Work Centre Redevelopment project. If, however, EPCOR brings an application for capital tracker treatment for 2015 expenditures on the Work Centre Redevelopment project in its 2015 true-up application, it will apply the AUF to the Work Centre Redevelopment project K factor for 2015.²³⁸

231. EPCOR explained why the AUFs related to the Work Centre Redevelopment project, which are an offset to capital costs, are determined using allocation factors calculated as a ratio of operating costs:

MR. BARANIECKI: We certainly feel it does, that it's -- that it is the appropriate sharing of those costs because the operating costs that we're using here is a representation of the number of employees, number of vehicles and other sort of inventory and warehousing required space, as well as yard space, and training space necessary for the transmission employees.

So it is a -- we feel it's a very fair and accurate allocation of the activity that transmission function is using out of this facility, and likewise, the distribution function is using as its facility.

And like you said, it is the same allocator we've used for the service centres we have now -- or what we're currently operating and the costs related to them.²³⁹

232. EPCOR added that it does not expect the ratio of operating costs to change over the forecast period and currently the transmission to distribution ratio of operating costs is approximately 23 per cent to 77 per cent.²⁴⁰

233. EPCOR explained, during the hearing, that the AUFs are not included in its accounting test schedules because the amounts do not represent a reduction to capital rate base, and the accounting test schedules need to reflect the full rate base amount for an asset, because the asset remains fully in EPCOR Distribution's rate base. The AUFs, instead, offset the capital costs to be collected from customers, based on usage of the asset, once the K factor has been

²³⁶ Exhibit 204087-X130.02, revised application, Table 1.0-1.

²³⁷ Exhibit 20407-X0175, Summary of Asset Usage Fees.

²³⁸ Exhibit 20407-X0131, EPCOR letter, August 24, 2015, paragraph 7.

²³⁹ Transcript, Volume 2, page 295, line 16 to page 296, line 5 (Mr. Baraniecki).

²⁴⁰ Transcript, Volume 2, page 295, line 16 to page 296, line 5 (Mr. Baraniecki).

determined.²⁴¹ Mr. Zurek explained EPCOR's decision not to include the AUFs in the accounting test schedules:

MR. ZUREK: We struggled a little with how to make this as clear and easy to understand as possible. We did look at revising the schedules, but we couldn't come up with a way kind of in the time that was allowed and sort of the mechanism that we had to provide that information to you where we were comfortable in showing the schedules in a clear and concise way. So we thought we would do it in the tables and try to explain it that way.

Q. If you had more time, which way would you have done it?

A. MR. ZUREK: Given more time, I think I would like to refine the models a little bit. But until I am able to sit down and go through all that, I can't really say which way I would go in the end.²⁴²

234. Neither the CCA nor the UCA made any comments on the AUFs proposed by EPCOR in this application in their respective arguments and reply arguments.

Commission findings

235. In EPCOR's 2015 to 2017 TFO tariff application, Proceeding 3539, the AUFs were brought before the Commission for approval for inclusion in EPCOR's transmission tariff. In the decision to EPCOR's TFO tariff application, Decision 3539 D01-2015, the Commission approved the AUFs as being a reasonable cost for EPCOR Transmission.²⁴³ That proceeding did not consider if the AUF's provided sufficient compensation to EPCOR Distribution for the use of its facilities by EPCOR Transmission.

236. The Commission acknowledges that the AUF amounts that EPCOR's transmission function will pay to its distribution function for the Work Centre Redevelopment project, which were approved in Decision 3539-D01-2015, were based on the total project forecast capital expenditures at the time the TFO tariff application was filed, which totalled \$82.49 million. In this application, EPCOR updated the total forecast capital expenditures for the project to \$85.09 million. Mr. Baraniecki explained, during the hearing, that EPCOR Transmission will pay the AUF based on actual expenditures and that EPCOR Transmission will have to make up for the costs differential not included in its approved rates for the 2015 to 2017 test period.²⁴⁴

237. The Commission has considered EPCOR Distribution's proposed approach to treating the AUFs for K factor calculation purposes and finds this approach to be reasonable. The Commission agrees with EPCOR that, because the AUFs that were in place prior to the start of the current PBR term are included as offsets in EPCOR Distribution's going-in rates, it is, therefore, reasonable to consider these existing AUFs subject to the I-X mechanism. The Commission also agrees with EPCOR that with respect to the new AUFs, which EPCOR's transmission function is paying to its distribution function, and which offset costs of capital tracker projects or programs, an adjustment is required outside of the I-X mechanism. In the absence of the adjustment for the new AUFs, double recovery of costs related to the project in question would occur given that the entire amount of the capital costs associated with the project

²⁴¹ Transcript, Volume 1, page 157, lines 2-22 (Mr. Baraniecki).

²⁴² Transcript, Volume 1, page 154, line 24 to page 155, line 12.

²⁴³ Decision 3539-D01-2015, paragraphs 275 and 277.

²⁴⁴ Transcript, Volume 2, page 300, line 22 to page 301, line 2 (Mr. Baraniecki).

would be included in EPCOR Distribution's rate base and accounting test schedules. At the same time, EPCOR's distribution function would be receiving the AUF from its transmission function, leading to a double recovery of project costs.

238. Regarding the AUF related to the OMS/DMS project, the Commission finds that the method of calculating the allocation factor proposed by EPCOR is reasonable. Accordingly, the Commission approves the forecast AUF to be included as an offset to the K factor in 2017 for the OMS/DMS capital tracker project.

239. In addition, the Commission has reviewed the three separate AUFs related to the Work Centre Redevelopment project, and finds that using the allocation factor method previously in place for EPCOR's General Plant Land and Buildings asset classes, which relies on a ratio of forecast operating costs related to EPCOR's service centres associated with the transmission function to the total forecast operating costs for EPCOR's service centres, is reasonable. The Commission approves the forecast AUFs for 2016 and 2017 to be included as an offset to the K factors in those years for the Work Centre Redevelopment project.

240. Because the AUF amounts do not represent a reduction to capital rate base, but instead, are an offset to a project's capital costs included in rates, the Commission understands EPCOR's hesitation to include the new AUFs in the capital additions part of its accounting test schedules.²⁴⁵ The Commission does, however, see merit in having the new AUFs included in another part of EPCOR's accounting test schedules (for example, dealing with the K factor calculation) because all the relevant K factor information will be set out in a single location, leading to better transparency in EPCOR's capital tracker applications. Accordingly, EPCOR is directed, in its future capital tracker applications, starting with the compliance filing to this decision, to include its new AUFs for the Work Centre Redevelopment project and the OMS/DMS project (and in the future, for any other capital tracker projects or programs to which new AUFs apply) in its accounting test schedules in a manner that demonstrates the amount of the AUF offset. In its compliance filing to this decision, EPCOR is also directed to explain its preferred approach to including the new AUFs in the accounting test schedules.

241. The Commission expects that in EPCOR's capital tracker true-up applications, it will offset the K factors, based on actual capital additions, for the projects discussed above by the AUF amounts calculated on the basis of actual capital additions. EPCOR is directed in its future capital tracker true-up applications, to include a table outlining the variance in AUFs between forecast and actual amounts, as well as the actual K factor amounts before and after the AUF is applied.

6.2 Previously approved capital tracker projects or programs

242. This section deals with EPCOR's projects or programs that were approved for capital tracker treatment on an actual or forecast basis in either Decision 2013-435 or in Decision 3100-D01-2015. It considers these projects or programs in the context of the true-up of 2014 actual expenditures and, if they are proposed to continue in 2016 and 2017, this section also considers the 2016 and 2017 forecasts.

²⁴⁵ Transcript, Volume 1, page 154, line 24 to page 155, line 12.

6.2.1 Projects or programs for which no objections were raised

243. In the application, there were a number of previously approved capital tracker projects or programs for which no objections were raised by the parties to this proceeding regarding need, scope, level, timing or costs. Table 8 summarises these projects and shows the 2014 actual capital expenditures on which the 2014 capital tracker true-up is based, the 2015 forecast capital additions approved in Decision 3100-D01-2015 or in the compliance filing, Decision 20210-D01-2015, as well as the 2016 and 2017 forecast capital additions proposed in the application.

Table 8. Projects or programs for which no issues were raised

	Project name (Business case appendix no.)	Capital additions (\$ million)			
		2014 actual	2015 approved	2016 forecast	2017 forecast
1	Third-Party Driven Relocations (Appendices A-1-1, A-1-2, B-1-3 and C-2)	12.36	26.01	12.46	10.80
2	New Underground Cable and Aerial Line Reconfigurations and Extensions to Meet Customer Growth (Appendix A-10)	6.53	8.33	8.21	6.28
3	Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement (Appendix A-7)	5.29	5.18	5.52	5.64
4	Capitalized Underground System Damage (Appendix A-8)	2.69	3.72	3.45	3.55
5	URD Servicing – Rebates, Acceptance Inspections & Terminations (Appendix A-11)	18.10	18.10	18.62	18.69
6	Capital Tools and Instrument Purchases (Appendix A-12)	0.91	0.87	1.19	0.58
7	Capitalized Aerial System Damage (Appendix A-13)	1.45	1.46	1.51	1.56
8	UID Servicing – Rebates, Acceptance Inspections & Terminations (Appendix A-14)	1.54	1.33	2.21	2.29
9	Replacement of Faulted Distribution PILC Cables (Appendix A-15)	2.16	1.01	1.35	1.40
10	Life Cycle Replacement of Network Transformers (Appendix A-20)	0.96	3.96	2.17	2.59

244. The Third-Party Driven Relocations program is composed of individual projects that involve the relocation of existing distribution facilities required by third parties, such as the City of Edmonton (City) under the terms of EPCOR's franchise agreement. The four Third-Party Driven Relocation projects included in the 2014 capital tracker true-up consist of the Southeast LRT Expansion (referred to as the Valley Line) Distribution System Relocations, ongoing project Franchise Agreement Driven Relocations and Conversions, the Walderdale Bridge Replacement Distribution System Relocations, and the Queen Elizabeth Highway II (QEII) and 41 Avenue SW Interchange Distribution System Relocations. Included in the 2016 and 2017 capital tracker forecasts are the Valley Line Distribution System Relocations and the Franchise Agreement Driven Relocations and Conversions. The need for this program as part of project assessment under capital tracker Criterion 1, was approved in Decision 2013-435²⁴⁶ for 2013 and later in Decision 3100-D01-2015²⁴⁷ for 2014 and 2015.

245. The 2014 approved forecast capital additions for this project were \$25.80 million, while the actual 2014 capital additions were \$12.36 million, resulting in a \$13.44 million negative variance. EPCOR explained that the primary causes of this variance were a delay in the

²⁴⁶ Decision 2013-435, paragraphs 851 and 858.

²⁴⁷ Decision 3100-D01-2015, paragraph 192.

completion of the downtown portion of the City's Valley Line LRT extension project,²⁴⁸ and project delays due to scheduling refinements made by the City in respect of its road improvement projects.²⁴⁹ The negative variance was offset by a \$0.42 million increase between forecast and actual costs resulting from the unanticipated need to replace 846 metres of existing distribution cable as part of the Waltherdale Bridge Replacement Distribution System Relocations project.²⁵⁰

246. The forecast capital additions for this project for 2016 and 2017, are \$12.46 million and \$10.80 million, respectively. The forecast for the Valley Line Distribution System Relocations project was developed based on updated information regarding the number of required relocations in the downtown area.²⁵¹ The forecast for the Franchise Agreement Driven Relocations and Conversions project was developed using similar capital additions to those experienced in 2013 and 2014 and through monthly discussions with subdivision developers and the City.²⁵²

247. The New Underground Cable and Aerial Line Reconfigurations and Extensions to Meet Customer Growth project consists of expansions and modifications to EPCOR's distribution system to meet load growth and maintain reliability in its service area. This project consists of specific, defined scope projects such as a circuit reconfiguration and an annual recurring set of projects, identified as needed, such as general aerial line reconfigurations. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 2013-435²⁵³ for 2013 and later in Decision 3100-D01-2015²⁵⁴ for 2014 and 2015.

248. The 2014 approved forecast capital additions for this project were \$9.54 million, while the actual 2014 capital additions were \$6.53 million, resulting in a \$3.01 million negative variance. EPCOR explained that the primary causes of this variance were a \$1.07 million decrease related to certain five kV upgrade projects, a \$0.85 million decrease due to the deferral of a project where the customer was not ready for service, and a \$0.84 million decrease in the actual amount of miscellaneous aerial reconfigurations required as compared to the forecast.²⁵⁵

249. The forecast capital additions for this project for 2016 and 2017 of \$8.21 million and \$6.28 million, respectively, were developed based on the scope of the specific circuit reconfiguration projects forecast for 2016 and 2017, using EPCOR's estimates for engineering, materials, and construction costs. For the recurring annual component of the project, the scope of work is based on three-year actual historical and forecast load growth, geographical location, and possible code requirement changes. The forecast scope of annual recurring work is then used to forecast expenditures based on the estimates for engineering, materials, and construction costs.²⁵⁶

250. The Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement project consists of providing new aerial and underground distribution transformers

²⁴⁸ Exhibit 20407-X0129, Appendix A-1-1, paragraphs 129-130.

²⁴⁹ Exhibit 20407-X0130.02, revised application, paragraphs 796-799.

²⁵⁰ Exhibit 20407-X0130.02, revised application, paragraphs 827.

²⁵¹ Exhibit 20407-X0129, Appendix A-1-1, paragraph 74.

²⁵² Exhibit 20407-X0114, Appendix A-1-2, paragraph 4.

²⁵³ Decision 2013-435, paragraph 883.

²⁵⁴ Decision 3100-D01-2015, paragraph 269.

²⁵⁵ Exhibit 20407-X0106, Appendix A-10, paragraph 133.

²⁵⁶ Exhibit 20407-X0106, Appendix A-10, paragraphs 85 and 120.

for distribution service as a result of replacing existing failed transformers or installing new transformers for new connections. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 2013-435²⁵⁷ for 2013 and later in Decision 3100-D01-2015²⁵⁸ for 2014 and 2015.

251. The 2014 approved forecast capital additions for this project were \$5.08 million, while the actual 2014 capital additions were \$5.29 million, resulting in a \$0.21 million positive variance. EPCOR explained that the primary cause of this variance was an increase of 79 new aerial transformers installed in addition to the forecast of 220 transformers, caused by higher than forecast lifecycle pole replacements.²⁵⁹ The forecast capital additions for this project for 2016 and 2017 of \$5.52 million and \$5.64 million, respectively, were developed based on a normalized three-year average of 2012 to 2014 actual costs.²⁶⁰

252. The Capitalized Underground System Damage project consists of the replacement of underground distribution infrastructure, such as switching cubicles, faulted underground cables, transformers and manholes, that have been damaged or that have failed or are about to fail. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 2013-435²⁶¹ for 2013 and later in Decision 3100-D01-2015²⁶² for 2014 and 2015.

253. The 2014 approved forecast capital additions for this project were \$3.64 million, while the actual 2014 capital additions were \$2.69 million, resulting in a \$0.95 million negative variance. EPCOR explained that the primary cause of this variance was a relatively lower volume of damaged underground facilities due to fewer weather-related outage events.²⁶³ The forecast capital additions for this project for 2016 and 2017 of \$3.45 million and \$3.55 million, respectively, were developed based on a normalized three-year average of EPCOR's 2012 to 2014 historical actual annual costs.²⁶⁴

254. The Underground Residential Distribution (URD) Servicing – Rebates, Acceptance Inspections & Terminations project includes development rebates, acceptance inspections, terminations, and distribution work performed by EPCOR with respect to (URD) servicing. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 2013-435²⁶⁵ for 2013 and later in Decision 3100-D01-2015²⁶⁶ for 2014 and 2015.

255. The 2014 approved forecast capital additions for this project were \$17.72 million, while the actual 2014 capital additions were \$18.10 million, resulting in a \$0.38 million positive variance. EPCOR explained that the primary cause of this variance was a \$1.23 million increase due to a higher than forecast volume of inspections and acceptance testing in 2014. This increase

²⁵⁷ Decision 2013-435, paragraph 895.

²⁵⁸ Decision 3100-D01-2015, paragraph 304.

²⁵⁹ Exhibit 20407-X0109, Appendix A-7, paragraph 34.

²⁶⁰ Exhibit 20407-X0109, Appendix A-7, paragraph 14.

²⁶¹ Decision 2013-435, paragraph 908.

²⁶² Decision 3100-D01-2015, paragraph 321.

²⁶³ Exhibit 20407-X0108, Appendix A-8, paragraph 26.

²⁶⁴ Exhibit 20407-X0108, Appendix A-8, paragraph 10.

²⁶⁵ Decision 2013-435, paragraph 923.

²⁶⁶ Decision 3100-D01-2015, paragraph 378.

was partially offset by a \$0.51 million decrease in total rebates paid to developers, because of a lower than forecast number of lots rebated in 2014 and a \$0.33 million decrease in URD distribution work by EPCOR, reflecting a lower than forecast amount of URD infrastructure installed.²⁶⁷ The forecast capital additions for this project for 2016 and 2017 of \$18.62 million and \$18.69 million, respectively, were developed based on the normalized three-year average of the 2012 to 2014 actual costs for the scope of work for inspections, terminations and distribution work completed by EPCOR. EPCOR explained that the forecasts for rebate amounts were determined by multiplying the forecast number of underground lots to be rebated by the URD rebate amount. To forecast the number of underground lots to be rebated, EPCOR used a three-year average of the actual annual number of lots that EPCOR serviced and for which it paid contributions in 2012 to 2014.²⁶⁸

256. The Capital Tools and Instrument Purchases project consists of refurbishing, replacing and upgrading EPCOR's distribution function tools and instruments that are required by EPCOR personnel for the safe construction, operation, inspection, maintenance and repair of EPCOR's distribution aerial and underground facilities. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 2013-435²⁶⁹ for 2013 and later in Decision 3100-D01-2015²⁷⁰ for 2014 and 2015.

257. The 2014 approved forecast capital additions for this project were \$0.76 million, while the actual 2014 capital additions were \$0.91 million, resulting in a \$0.15 million positive variance. EPCOR explained that the primary causes of this variance were a \$0.08 million increase related to EPCOR's decision to buy six additional power quality recorder meters over the long term to carry out its forecast new customer connection and distribution system reconfiguration and extension workload, a \$0.04 million increase related to tools for three additional vehicles due to EPCOR's decision to increase the number of crews required to handle the increased volume of underground network distribution related work, and a \$0.06 million increase due to the earlier than anticipated delivery of a thermographic camera, and replacement of obsolescent bucket truck rescue equipment, and other miscellaneous small increases. These increases were partially offset by a \$0.03 million decrease due to EPCOR's decision not to proceed with the purchase of a fault locator test unit.²⁷¹ The forecast capital additions for this project for 2016 and 2017 of \$1.19 million and \$0.58 million, respectively, were developed based on management's assessment of the type and quantity of additional or replacement tools and instruments required in those years, actual historical cost experienced in previous years, and information collected from tool and instrument suppliers.²⁷²

258. The Capitalized Aerial System Damage project consists of the replacement of EPCOR's aerial distribution facilities that have been damaged or that have failed or are about to fail. The need for this project as part of the project assessment under capital tracker Criterion 1, was

²⁶⁷ Exhibit 20407-X0093, Appendix A-11, paragraphs 34-36.

²⁶⁸ Exhibit 20407-X0093, Appendix A-11, paragraphs 19-21.

²⁶⁹ Decision 2013-435, paragraph 927.

²⁷⁰ Decision 3100-D01-2015, paragraph 398.

²⁷¹ Exhibit 20407-X0092, Appendix A-12, paragraphs 61-62.

²⁷² Exhibit 20407-X0092, Appendix A-12, paragraph 40.

approved in Decision 3100-D01-2015²⁷³ for 2014 and 2015. EPCOR did not apply for capital tracker treatment for this project in 2013.

259. The 2014 approved forecast capital additions for this project were \$1.41 million, while the actual 2014 capital additions were \$1.45 million, resulting in a \$0.04 million positive variance. EPCOR explained that the primary cause of this variance was a higher volume of system damage and repairs required than reflected in the historical average used for forecasting purposes.²⁷⁴ The forecast capital additions for this project for 2016 and 2017 of \$1.51 million and \$1.56 million, respectively, were developed based on a normalized three-year average of EPCOR's 2012 to 2014 historical actual annual costs.²⁷⁵

260. The UID Servicing – Rebates, Acceptance Inspections & Terminations project consists of building new underground 15- and 25-kV primary cables, switching cubicles, and ancillary equipment in order to connect new industrial lots in EPCOR's service area to the distribution system, and carrying out modifications to correct for double lugging. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 3100-D01-2015²⁷⁶ on an actual basis for 2013, and on a forecast basis for 2014 and 2015.

261. The 2014 approved forecast capital additions for this project were \$1.30 million, while the actual 2014 capital additions were \$1.54 million, resulting in a \$0.24 million positive variance. EPCOR explained that the primary cause of this variance was a higher number of hectares serviced.²⁷⁷ The forecast capital additions for this project for 2016 and 2017 of \$2.21 million and \$2.29 million, respectively, were developed based on the number of hectares of developed land forecast to be serviced by UID and the estimated cost to service these UID projects. The forecast of the number of hectares of UID was determined by EPCOR based on a three-year historical average of the number of hectares serviced from 2012 to 2014. The servicing costs forecast was based on EPCOR's historical actual cost of UID projects constructed in previous years, and current cost estimates for UID facility engineering, materials, testing and commissioning.²⁷⁸

262. The Replacement of Faulted Distribution PILC Cables project consists of the replacement of faulted distribution PILC cable and cable accessories as cable faults occur. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 3100-D01-2015²⁷⁹ for 2014 and 2015.

263. The 2014 approved forecast capital additions for this project were \$0.98 million, while the actual 2014 capital additions were \$2.16 million, resulting in a \$1.18 million positive variance. EPCOR explained that the primary cause of this variance was a higher than forecast number of faulted PILC cables, which EPCOR was required to replace.²⁸⁰ The forecast capital additions for this project for 2016 and 2017 of \$1.35 million and \$1.40 million, respectively,

²⁷³ Decision 3100-D01-2015, paragraph 454.

²⁷⁴ Exhibit 20407-X0091, Appendix A-13, paragraphs 22 and 24.

²⁷⁵ Exhibit 20407-X0091, Appendix A-13, paragraph 11.

²⁷⁶ Decision 3100-D01-2015, paragraphs 469 and 472.

²⁷⁷ Exhibit 20407-X0090, Appendix A-14, paragraph 33.

²⁷⁸ Exhibit 20407-X0090, Appendix A-14, paragraphs 17-18.

²⁷⁹ Decision 3100-D01-2015, paragraph 489.

²⁸⁰ Exhibit 20407-X0089, Appendix A-15, paragraph 31.

were developed based on a three-year historical average of the annual actual number of PILC failures EPCOR experienced on its system during 2012-2014, multiplied by the normalized three-year average cost to replace a faulted PILC cable based on EPCOR's historical actual costs with respect to all failed PILC replacements made during the 2012 to 2014 period.²⁸¹

264. The Life Cycle Replacement of Network Transformers project consists of the replacement of network transformers in downtown Edmonton. Aging transformers are replaced before they fail based on inspections to determine the units that have deteriorated and are at an increased risk of failure. On average, as part of the Life Cycle Replacement of Network Transformers project, EPCOR replaces four to six network transformers annually, with five replacements forecast in each of 2016 and 2017. The need for this project as part of the project assessment under capital tracker Criterion 1, was approved in Decision 3100-D01-2015²⁸² for 2014 and 2015.

265. As was the case for 2014 and 2015, the number of network transformers replaced each year as part of this project is dependent upon the number of network transformer installations required as a part of EPCOR's LRT relocation projects. EPCOR's internal resources available to install network transformers are limited.²⁸³ EPCOR explained that, in addition to replacing five transformers as part of the Life Cycle Replacement of Network Transformers project, it is also forecasting to replace two network transformers in 2016 and four network transformers in 2017 as part of the Southeast LRT Expansion Distribution System Relocations project.²⁸⁴

266. The 2014 approved forecast capital additions for this project were \$0.99 million, while the actual 2014 capital additions were \$0.96 million, resulting in a \$0.03 million negative variance. EPCOR explained that the primary cause of this variance was a \$0.40 million decrease in expenditures given that EPCOR was unable to install vista switches on three new elbow transformers in 2014. The switch installations were deferred into 2015. That decrease was offset by a \$0.37 million increase that resulted from EPCOR installing an additional five transformers in 2014. The additional five transformers were replaced after EPCOR determined they required immediate attention following inspection and testing.²⁸⁵

267. The forecast capital additions for this project for 2016 and 2017 of \$2.17 million and \$2.59 million, respectively, were developed based on EPCOR's estimates of engineering, material, project management, and construction costs required for the project, while considering historical cost information from completed replacement projects.²⁸⁶ EPCOR explained that the average unit cost per transformer is increasing as compared to historical levels because old oil switch network transformers are being replaced by vacuum switch elbow transformers with remote monitoring and dead front protectors. The change in transformer type is due to Institute of Electrical and Electronics Engineers guidelines and safety issues.²⁸⁷

²⁸¹ Exhibit 20407-X0089, Appendix A-15, paragraphs 14-15.

²⁸² Decision 3100-D01-2015, paragraph 536.

²⁸³ Decision 3100-D01-2015, paragraph 529.

²⁸⁴ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-039(a).

²⁸⁵ Exhibit 20407-X0077, Appendix A-20, paragraphs 43-44.

²⁸⁶ Exhibit 20407-X0077, Appendix A-20, paragraph 19.

²⁸⁷ Exhibit 20407-X0077, Appendix A-20, paragraph 20.

Commission findings

268. In Decision 2013-435, and/or Decision 3100-D01-2015, the Commission approved the need on an actual or forecast basis, for each of the projects or programs listed in Table 8 above, for purposes of capital tracker treatment in one or more of 2013, 2014, or 2015. Further, the Commission determined that the proposed scope, level, timing and forecast costs for these projects and programs were reasonable. Therefore, the Commission has previously determined that each of the projects or programs listed in Table 8 above satisfied the project assessment requirement of capital tracker Criterion 1 in one or more previous years. In addition, in Decision 3100-D01-2015 and the compliance filing Decision 20210-D01-2015 in relation thereto, the Commission approved the actual scope, level, timing and costs of projects and programs included in the 2013 capital tracker true-up application, as prudent.

269. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that any of the projects or programs listed in Table 8 was not required in 2014.

270. With respect to the scope, level and timing of the each of the projects or programs listed in Table 8 carried out in 2014, the Commission has reviewed EPCOR's 2014 actual capital additions associated with each of these projects or programs and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for these capital trackers and approved in Decision 3100-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for each of these projects or programs in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

271. In the present application, EPCOR requested capital tracker treatment for these projects or programs on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that any of the projects or programs listed in Table 8 is not required to continue in 2016 or 2017.

272. With respect to the scope, level and timing of each of the projects or programs listed in Table 8 for 2016 and 2017, the Commission has reviewed the business cases and the relevant portions of the record for each of these projects or programs and finds the forecast scope, level and timing of each of these projects or programs for 2016 and 2017 to be reasonable. The Commission observes that the 2016 and 2017 forecast costs for each of these projects or programs are generally consistent with the variance explanations provided in the business case for the actual expenditures over the most recent 5-year period. The Commission has reviewed the information supporting EPCOR's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable based on the respective forecasting methodologies employed, as

described earlier in this section, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

273. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for each for the projects or programs listed in Table 8 above are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that each of these projects or programs satisfies the project assessment requirement of Criterion 1 for 2016 and 2017.

6.2.2 Life Cycle Replacement and Extension of Underground Distribution Cable

274. This ongoing life cycle replacement project consists of refurbishing and replacing aged underground cables to maintain reliability.²⁸⁸ EPCOR noted that this project was approved as a capital tracker in Decision 2013-435 for 2013 and in Decision 3100-D01-2015 for 2014-2015. This project was also approved in prior decisions dealing with EPCOR's cost-of-service tariff applications.²⁸⁹ EPCOR provided a business case and an engineering study for the Life Cycle Replacement and Extension of Underground Distribution Cable project in Appendix A-3 of the application.

275. The 2014 approved forecast capital additions for this project were \$14.05 million, based on replacing and refurbishing through injection 22 km and 25 km of cable, respectively. EPCOR's actual capital additions for this project for 2014 were \$10.45 million, for a negative variance of \$3.60 million. In 2014, EPCOR replaced approximately 14.5 km of cable and refurbished approximately 10.8 km of cable. EPCOR explained that less cable was actually replaced and refurbished than planned, due to the rescheduling of crews to higher priority work. Also, because of PBR uncertainty in 2013, the work planned for 2014 was not started until the second quarter of 2014.²⁹⁰

276. Regarding the prudence of its actual 2014 capital additions, EPCOR confirmed that the 2014 work on this project was completed in accordance with its formal project management policies and procedures, as described in the application, and the costs included in this project consisted of materials, engineering, and labour and equipment costs related to construction, equipment terminations, switching, and cable injection. EPCOR described the steps it took to ensure that the work was completed in a cost effective manner.²⁹¹

277. EPCOR confirmed that "nothing occurred between the date of EDTI's 2014 Tracker Application and the work completed in 2014 that obviated the need for this project, or that would have materially impacted the conclusions reached in EDTI's analysis of alternatives."²⁹²

278. EPCOR's forecast capital additions associated with this project were \$12.60 million in 2016 and \$13.53 million in 2017. EPCOR stated that capital expenditures for this project were

²⁸⁸ Exhibit 20407-X0130.02, revised application, paragraph 308.

²⁸⁹ Exhibit 20407-X0130.02, revised application, paragraph 308.

²⁹⁰ Exhibit 20407-X0130.02, revised application, paragraphs 844 and 864.

²⁹¹ Exhibit 20407-X0130.02, revised application, paragraphs 847-863.

²⁹² Exhibit 20407-X0130.02, revised application, paragraph 843.

based on replacing approximately 16 km of cable, and refurbishing through injection, 25 km of cable each year.²⁹³ EPCOR used its historical cost experience in completing cable replacements and injections to estimate the costs.²⁹⁴

279. In the 2006 study appended to the business case, KEMA Inc. recommended that EPCOR annually replace 25 km of 350 MCM or larger cable and inject 16 km of 1/0 or smaller cable. To reduce the financial effect, EPCOR decided to reverse the ratio and then monitor the effect of its decision on the reliability of the system.²⁹⁵

280. In response to an information request by the Commission, EPCOR provided a table setting out the planned and actual length of underground cable replaced and refurbished for the years 2007 to 2014.²⁹⁶ The Commission has prepared the following table using the information provided by EPCOR, which shows that during the period 2007 to 2014, EPCOR replaced or refurbished only 50 per cent of the total cable length recommended by KEMA.

Table 9. Comparison of kilometres (km) of cable replaced/refurbished actuals to planned

(A) Year	(B) Kilometres injected		(C) Kilometres replaced		(D) Total replaced/refurbished		(E) Study recommendation	(F) Total actual cost (\$ million)
	Planned	Actual	Planned	Actual	Planned	Actual		
2007	3.2	3.2	1.45	1.45	4.65	4.65	40	0.36
2008	28.9	4.47	5.39	6.31	34.29	10.78	40	3.35
2009	28.9	11	5.1	5.68	34	16.68	40	2.56
2010	25	22	16	10	41	32	40	4.07
2011	25	18	16	13.7	41	31.7	40	8.50
2012	25	18	16	14	41	32	40	10.17
2013	25	0.6	17	5	42	5.6	40	3.21
2014	25	10.8	22	14.5	47	25.3	40	10.45
Total	186	88.07	98.94	70.64	284.94	158.71	320	

281. In response to Commission counsel questioning, Ms. Hull, for EPCOR, explained that the low volume of actual replacement or refurbishment in 2007, 2008 and 2009 was attributed to EPCOR learning how to do the work, and noted that the volume for 2010, 2011 and 2012 was at 80 per cent of planned activities. Ms. Hull further explained that the decrease in 2013 was due to a temporary hold because of EPCOR's uncertainty about approval of its capital tracker application.²⁹⁷

282. In response to another related information request by the Commission, EPCOR provided a table showing the system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) reliability indicators attributable to underground cable failures for the years 2008 to 2014:

²⁹³ Exhibit 20407-X0130.02, revised application, paragraphs 310-311.

²⁹⁴ Exhibit 20407-X0113, Appendix A-3, paragraph 27.

²⁹⁵ Exhibit 20407-X0113, Appendix A-3, paragraph 18.

²⁹⁶ Exhibit 20407-X0146, Table EDTI-AUC-2015JUN26-021-1.

²⁹⁷ Transcript, Volume 2, page 238, line 19 to page 239, line 1 (Ms. Hull).

Table 10. 2008-2014 SAIFI and SAIDI attributable to underground cable failures²⁹⁸

	Year	A SAIFI	B SAIDI (hours)
1	2008	0.165	0.217
2	2009	0.160	0.157
3	2010	0.099	0.104
4	2011	0.117	0.098
5	2012	0.064	0.153
6	2013	0.093	0.083
7	2014	0.125	0.169

283. When questioned by Commission counsel regarding the apparent reliability index improvements from 2008 to 2010, and then a cycle of degradation and improvement onwards, Ms. Hull attributed the trend from 2008 to 2010 to EPCOR addressing the worst performing segments of its cables first.²⁹⁹ Ms. Hull confirmed that SAIFI and SAIDI will go up and down over the course of the project, but over the 25-year life of the program, improvement to SAIFI and SAIDI measures is expected.³⁰⁰ Ms. Hull further submitted that continuation of the program at a 40 km per year level is supported by 19 years of data from 1986 to 2005, the age of existing cables and associated failure curves, and improvements in SAIFI and SAIDI since the start of the project. Furthermore, EPCOR stated that it is intending to refresh the failure models with the last nine years of data in 2016, and while the update could show a decrease from the annual 40 km per year refurbishment or replacement level, it is more likely that the new report will show a requirement for the same or a higher level of cable refurbishment or replacement.³⁰¹

284. The UCA was of the view that EPCOR did not establish that limiting the scope of the project as it has done historically, has led to a deterioration in service quality and safety, and, accordingly, has failed to show that the proposed increased work level for this project is necessary.³⁰² The UCA submitted that the Commission should direct EPCOR to continue with the project at the level achieved in recent years, that is 20 km per year for 2016 and 2017.³⁰³ The CCA agreed, recommending that EPCOR continue its cable refurbishment and replacement program at the current 50 per cent of planned levels until an updated study is available.³⁰⁴

Commission findings

285. In Decision 2013-435,³⁰⁵ and later in Decision 3100-D01-2015,³⁰⁶ the Commission approved the need for the Life Cycle Replacement and Extension of Underground Distribution Cable project for purposes of capital tracker treatment for 2013 and 2014-2015, respectively.

²⁹⁸ Exhibit 20407-X0146, Table EDTI-AUC-2015JUN26-021-2.

²⁹⁹ Transcript, Volume 2, page 243, lines 5-9 (Ms. Hull).

³⁰⁰ Transcript, Volume 2, page 244, line 16 to page 245, line 13 (Ms. Hull).

³⁰¹ Transcript, Volume 2, pages 245-259, (Ms. Hull).

³⁰² Exhibit 20407-X0232, UCA argument, paragraph 4a.

³⁰³ Exhibit 20407-X0232, UCA argument, paragraph 63.

³⁰⁴ Exhibit 20407-X0238, CCA reply argument, paragraphs 46-54.

³⁰⁵ Decision 2013-435, paragraph 873.

³⁰⁶ Decision 3100-D01-2015, paragraph 233.

Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfies the project assessment requirement of Criterion 1. In addition, in Decision 3100-D01-2015 and in the compliance filing Decision 20210-D01-2015 in relation thereto, the Commission approved the actual scope, level, timing and costs of this project, included in the 2013 capital tracker true-up application, as prudent.

286. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Life Cycle Replacement and Extension of Underground Distribution Cable project was not required in 2014.

287. With respect to the scope, level and timing of the project carried out in 2014, the Commission has reviewed EPCOR's 2014 actual capital additions of \$10.45 million associated with this project and notes that the actual capital additions are approximately 50 per cent of the forecast outlined in the business case for this capital tracker and approved in Decision 3100-D01-2015. While the continued underperformance in completion of forecast work for this project is of concern to the Commission, in light of the evidence supporting the costs of the 2014 actual capital additions for this project, including the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, the Commission finds the actual costs to be prudent, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

288. In the present application, EPCOR also requested capital tracker treatment for this project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds insufficient evidence on the record of this proceeding to indicate that the Life Cycle Replacement and Extension of Underground Distribution Cable project is not required to continue in 2016 or 2017.

289. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and agrees with the UCA that EPCOR did not adequately support the need to increase the level of replacements and refurbishments from historical levels to 40 km per year to maintain service reliability and safety at adequate levels. Table 9 shows that since 2010, after the project start-up period, EPCOR has yet to achieve its forecast replacements/refurbishments of cable length. The forecast capital additions for this project for 2016 and 2017 of \$12.60 and \$13.53 million, respectively, were based on replacing approximately 16 km of cable and refurbishing through injection, 25 km of cable each year. During the three-year time period from 2011 to 2014, excluding 2013 when EPCOR deferred a significant portion of expenditures on

this project due to “uncertainty respecting the capital tracker mechanism,”³⁰⁷ EPCOR replaced or refurbished on average, approximately 30 km per year, at an average cost of \$9.7 million. Given EPCOR’s historical pattern of actual expenditures for this project, the Commission finds the 2016 and 2017 forecast capital additions for this project based on a three-year average of \$9.7 million, to be reasonable.

290. In Section 6.1 of this decision, the Commission directed certain adjustments applicable to all projects and programs proposed for capital tracker treatment, such as an adjustment to certain labour escalation rates and allocated capital overhead amounts, including capitalized STIP amounts. Accordingly, the Commission directs EPCOR, in its compliance filing to this decision, to revise its forecast for 2016 and 2017 capital additions for this project using a three-year average of \$9.7 million, adjusted for 2016 and 2017 using the labour escalation rates and allocated capital overhead amounts approved in Section 6.1, and reflect these revised forecast capital additions in its 2016 and 2017 forecast K factor calculation. The Commission also directs EPCOR to explain the methodology used to determine the 2016 and 2017 capital additions for this project, based on the three-year average of \$9.7 million, and escalation factors approved in Section 6.1.

291. In light of the above, the Commission is prepared to accept that the Life Cycle Replacement and Extension of Underground Distribution Cable project, with the forecast capital additions as modified by the Commission above, satisfies the project assessment requirement of Criterion 1 for 2016 and 2017.

6.2.3 New 15-kV and 25-kV Circuit Additions

292. This ongoing project consists of the construction of new distribution circuits needed to maintain reliability and provide sufficient capacity for EPCOR’s distribution system. This project is required as a result of customer growth in EPCOR’s service territory. EPCOR noted that this project was approved for capital tracker treatment in Decision 2013-435 for 2013 and in Decision 3100-D01-2015 for 2014 and 2015. This project was also approved in prior decisions dealing with EPCOR’s cost-of-service tariff applications.³⁰⁸ EPCOR provided a business case and engineering diagrams for the New 15-kV and 25-kV Circuit Additions project in Appendix A-4 of its application.

293. In 2014, EPCOR had forecast the completion of two new circuit additions with a forecast cost of \$4.46 million. The 2014 actual capital expenditures for the New 15-kV and 25-kV Circuit Additions project were \$4.57 million, which represents a positive variance of \$0.11 million.³⁰⁹ EPCOR explained that the variance included a \$0.19 million increase in the 13SU circuit addition project, which was the result of EPCOR installing 750 MCM copper XLPE cable at greater depths than the 500 MCM aluminum XLPE cable that it had originally forecast for installation. A total of 1.1 km of 750 MCM copper XPLE cable was required to be installed.³¹⁰ The \$0.19 million increase was offset by a \$0.08 million decrease in the 23C circuit addition project. That project had a lower than forecast cost because EPCOR’s detailed engineering

³⁰⁷ Decision 3100-D01-2015, paragraph 85 and Table 3 on page 23.

³⁰⁸ Exhibit 20407-X0112, Appendix A-4, paragraph 2.

³⁰⁹ Exhibit 20407-X0112, Appendix A-4, page 26, Table 6.0-1.

³¹⁰ Exhibit 20407-X0112, Appendix A-4, paragraph 120.

design determined that different switches could be installed and less aerial work than forecast was needed, given EPCOR's ability to coordinate work with other activities in the area.³¹¹

294. Regarding the prudence of its actual 2014 capital additions, EPCOR confirmed that the 2014 work on this project was completed in accordance with its formal project management policies and procedures, as described in the application, and the costs included in this project consisted primarily of materials and construction costs (98 per cent).³¹² EPCOR described the steps it took to ensure that the work was completed in a cost effective manner.³¹³

295. EPCOR confirmed that “nothing occurred between the date of EDTI's 2014 Tracker Application and the work completed in 2014 that obviated the need for this project, or that would have materially impacted the conclusions reached in EDTI's analysis of alternatives.”³¹⁴

296. In each of 2016 and 2017, EPCOR forecast to complete five circuit addition projects. The following table was provided by EPCOR outlining the forecast capital additions associated with each circuit addition project:

Table 11. 2016 and 2017 forecast New 15-kV and 25-kV Circuit Addition project capital additions³¹⁵

Circuit addition project	2016 forecast	2017 forecast
	(\$ million)	
Circuit D84	1.29	-
Circuits V29 and V48	0.81	-
Circuit 24C	2.08	-
Circuit 13E	1.29	-
Circuits V42 and V58	-	0.85
Circuit 14C	-	1.83
Circuit 23PM	-	5.10
Circuit 24SU	-	4.72
Total	5.48	12.49

297. In support of each circuit addition project forecast for 2016 and 2017, EPCOR provided a detailed project description,³¹⁶ a project schedule and milestone description,³¹⁷ load growth forecasts for the respective areas where circuits are being installed,³¹⁸ an alternative circuit construction project to meet the forecast load growth,³¹⁹ and engineering diagrams.³²⁰

³¹¹ Exhibit 20407-X0112, Appendix A-4, paragraph 121.

³¹² Exhibit 20407-X0130.02, revised application, paragraph 871.

³¹³ Exhibit 20407-X0130.02, revised application, paragraphs 872-880.

³¹⁴ Exhibit 20407-X0130.02, revised application, paragraph 867.

³¹⁵ Exhibit 20407-X0112, Appendix A-4, page 17, Table 3.2-1.

³¹⁶ Exhibit 20407-X0112, Appendix A-4, Section 2.1.

³¹⁷ Exhibit 20407-X0112, Appendix A-4, page 16, Table 3.1-1.

³¹⁸ Exhibit 20407-X0112, Appendix A-4, Section 2.2.

³¹⁹ Exhibit 20407-X0112, Appendix A-4, Section 4.

³²⁰ Exhibit 20407-X0112, Appendix A-4, attachments 1-17.

298. EPCOR further provided historical unit costs for different components required for circuit addition projects in an IR response to the Commission.³²¹ By way of an undertaking response, EPCOR provided forecast unit costs for each of the 2016 and 2017 circuit addition projects.³²²

299. By way of an IR, the UCA inquired as to the project cost increases from the 2010 to 2014 period to those forecast for 2016 and 2017. As well, the UCA sought an explanation for the cost differences between the 23PM and 24SU circuits, and the other circuit addition projects. EPCOR explained that the overall project costs in 2017 were forecast to be higher than in 2016, as well as the prior period actuals, given the forecast costs for the 23PM and 24SU circuits. EPCOR also added that from 2010 to 2014, one to three circuit additions were completed each year, as compared to five circuit additions forecast in 2017.³²³

300. Regarding the forecast costs for the 23PM circuit addition, EPCOR indicated that the project requires 6.8 km of cable to be installed, 1.2 km of which is concrete-encased ductline required to cross Anthony Henday Drive in Edmonton.³²⁴ The 24SU project has a length of 3.95 km, which consists of 1.2 km of six-way concrete-encased ductline and 1.7 km of direct buried three-way ductline with manholes.³²⁵ EPCOR explained the other forecast circuit additions for 2016 and 2017 were shorter in length and are not expected to require new ductline construction, and provided the following table comparing the projects:

Table 12. 2016 and 2017 forecast New 15-kV and 25-kV Circuit Addition projects by component³²⁶

Year	Circuit	Total length (km)	Cable in ductline (km)	Cable in conduit/direct buried (km)	Aerial (km)	Civil ductline construction (km)	Other
2016	D84	3.5	2.0	1.5	-	-	-
2016	V29	0.7	0.7	-	-	-	-
2016	V48	1.0	1.0	-	-	-	-
2016	24C	4.35	0.15	4.20	-	-	5 switching cubicles
2016	13E	2.6	0.3	1.5	0.8	-	1 switching cubicle
2017	V42	1.0	1.0	-	-	-	-
2017	V58	1.0	1.0	-	-	-	-
2017	14C	4.75	0.15	3.2	1.4	-	2 switching cubicles
2017	23PM	6.8	2.3	4.5	-	1.2	3 switching cubicles
2017	24SU	3.95	2.9	1.05	-	2.9	-

³²¹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-022(b).

³²² Exhibit 20407-X0199, undertaking response.

³²³ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-024(a).

³²⁴ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-024(b).

³²⁵ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-024(c).

³²⁶ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-024(b).

301. During the hearing, EPCOR was asked why in 2016 and 2017, five circuit addition projects were forecast annually as compared to 2014 and 2015, where EPCOR had forecast to complete three circuit additions per year, and if there was the possibility for EPCOR to have spread the circuit addition projects out over time. Ms. Hull responded:

So of the five circuits for 2017, two of them are for customer-related loads, and those are the V42 and V58. Those are circuits going into the new arena district downtown or the ice district, as they're calling it, for feeding the new buildings that are going up in and around the arena.

So those would not have been able to have been threaded earlier because the load wasn't there; the need wasn't there. They're redeveloping those sites for those buildings.³²⁷

302. Ms. Hull also confirmed that EPCOR is not expected to require five circuit additions annually in future years.³²⁸

303. Given that the V29, V48, V42 and V58 circuit addition projects are required to accommodate new developments in downtown Edmonton, such as a hotel, retail building, and officer tower, EPCOR was asked whether any customer contribution amounts were expected for those projects. EPCOR explained that contributions would be received if the cost to complete those circuit additions is in excess of approved maximum investment levels.³²⁹ Ms. Hull stated that at the time of the hearing, it was unknown whether customer contributions would be received and outlined the process for determining if a contribution is required:

What happens is we verify the customer load that's coming on. And based on the amount of load and our maximum investment towards that load, we see if there's any net difference between what we're spending to install the circuit versus what they're actually bringing on in terms of load. If there's a difference, yes, there will be a customer contribution from the customer. If the load that's being brought on by the customer covers off the costs for installing the new circuit, then there won't be a customer contribution.³³⁰

304. Neither the UCA nor the CCA commented on the New 15-kV and 25-kV Circuit Additions project in their respective arguments and reply arguments.

Commission findings

305. In Decision 2013-435,³³¹ and later in Decision 3100-D01-2015,³³² the Commission approved the need for the New 15-kV and 25-kV Circuit Additions project for purposes of capital tracker treatment for 2013 and 2014-2015, respectively. Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1. In addition, in Decision 3100-D01-2015 and in the compliance filing Decision 20210-D01-2015 in relation thereto, the Commission approved

³²⁷ Transcript, Volume 3, page 388, lines 16-25 (Ms. Hull).

³²⁸ Transcript, Volume 3, page 390, lines 16-24 (Ms. Hull).

³²⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-023(a).

³³⁰ Transcript, Volume 3, page 391, lines 7-16 (Ms. Hull).

³³¹ Decision 2013-435, paragraph 879.

³³² Decision 3100-D01-2015, paragraph 253.

the actual scope, level, timing and costs of this project, included in the 2013 capital tracker true-up application, as prudent.³³³

306. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the New 15-kV and 25-kV Circuit Additions project was not required in 2014.

307. With respect to the scope, level and timing of the project carried out in 2014, the Commission has reviewed EPCOR's 2014 actual capital additions of \$4.57 million associated with this project, which were \$0.11 million higher than the \$4.46 million forecast approved in Decision 3100-D01-2015,³³⁴ primarily because of required changes to the 13SU circuit addition project, as explained above. The Commission has also reviewed the costs of the 2014 actual capital additions for this project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

308. In the present application, EPCOR also requested capital tracker treatment for this project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the New 15-kV and 25-kV Circuit Additions project is not required to continue in 2016 or 2017.

309. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are \$5.48 million in 2016 and \$12.49 million in 2017. The Commission has reviewed the information supporting EPCOR's forecasts and finds the total annual cost forecast to be reasonable based on the explanation given by EPCOR that a greater number of circuit additions are required in 2016 and 2017 to connect new development projects in Edmonton, and based on the component cost information for the forecast circuit addition projects provided in Table 12 above.

310. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the New 15-kV and 25-kV Circuit Additions project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in

³³³ Decision 20210-D01-2015, paragraph 20.

³³⁴ Decision 3100-D01-2015, paragraph 252.

Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.2.4 Distribution Pole and Aerial Line Life Cycle Replacements

311. This ongoing project consists of the replacement of distribution poles, conductors and associated assets and the conversion of five-kV distribution circuits to 15 kV when a significant number of distribution poles on a particular five-kV circuit are being replaced.³³⁵ EPCOR noted that this project was approved as a capital tracker in Decision 2013-435 for 2013 and in Decision 3100-D01-2015 for 2015. This project was also approved in prior decisions dealing with EPCOR's cost-of-service tariff applications.³³⁶ EPCOR provided a business case and an engineering study for the Distribution Pole and Aerial Line Life Cycle Replacements project in Appendix A-6 of the application.

312. As noted in Decision 3100-D01-2015, EPCOR requested capital tracker treatment for this project in 2015 only, because the project did not meet the first tier of the materiality threshold for 2014 on a forecast basis.³³⁷ EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in this application.

313. EPCOR explained that poles, conductors and associated equipment are replaced when they no longer meet safety, structural and/or clearance requirements. EPCOR noted that its staff use their professional judgment and experience to select poles and conductors for replacement.³³⁸ EPCOR also indicated that when a significant number of distribution poles on a particular five-kV circuit are being replaced, EPCOR converts the distribution circuit to 15 kV. EPCOR further explained that in order to replace a pole, all existing attachments must be removed; therefore, once a decision is made to replace a pole, the other assets on the pole are replaced as well.³³⁹

314. In response to a Commission IR, EPCOR confirmed that five-kV circuits are only upgraded when they are identified as requiring replacement under its inspection program. No five-kV circuits are upgraded under this program solely to achieve an upgrade to 15 kV. However, some immediately adjacent five-kV assets may be replaced to meet design criteria such as minimum height clearances for road crossings, electrical clearance requirements between conductors, uplift due to height differences to adjacent poles, and to accommodate "no anchor" easements.³⁴⁰

315. EPCOR forecast capital additions associated with this project to be \$3.62 million in 2016 and \$4.15 million in 2017.³⁴¹ The number of poles forecast for replacement in 2016 and 2017 is based on current and historical inspection results.³⁴² EPCOR noted that it uses a three-year normalized average total combined (pole, conductor and associated accessories) unit pole cost to

³³⁵ Exhibit 20407-X0130.02, revised application, paragraph 354.

³³⁶ Exhibit 20407-X0130.02, revised application, paragraph 356.

³³⁷ Decision 3100-D01-2015, paragraph 286.

³³⁸ Exhibit 20407-X0110, Appendix A-6, paragraphs 4-5.

³³⁹ Exhibit 20407-X0110, Appendix A-6, paragraph 41.

³⁴⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-026(a).

³⁴¹ Exhibit 20407-X0110, Appendix A-6, Table 3.3-1 on page 21.

³⁴² Exhibit 20407-X0110, Appendix A-6, paragraph 40.

forecast its costs, which takes into consideration the complete cost of pole replacements, transformer replacements and line hardware replacements.³⁴³

316. In the business case, EPCOR indicated it achieved some efficiency gains in 2014, allowing it to complete its forecast work for this project below forecast cost. These efficiencies were realized because many of the poles replaced for this project in 2014 were in the same vicinity, resulting in decreased labour costs.³⁴⁴ During the hearing, Ms. Hull noted that these efficiencies are reflected in EPCOR's 2016 and 2017 forecast costs, using the three-year normalized average forecasting methodology (which includes the 2014 actual costs) to determine its forecast costs for this project.³⁴⁵

317. Neither the UCA nor the CCA commented on the Distribution Pole and Aerial Line Life Cycle Replacements project in their respective arguments and reply arguments.

Commission findings

318. In Decision 2013-435,³⁴⁶ and later in Decision 3100-D01-2015,³⁴⁷ the Commission approved the need for the Distribution Pole and Aerial Line Life Cycle Replacement project for purposes of capital tracker treatment for 2013 and 2015, respectively. Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1. However, at the time of the 2013 capital tracker true-up, this project did not meet at least one capital tracker criterion on an actual basis in 2013, as set out in the compliance filing Decision 20210-D01-2015,³⁴⁸ and, therefore, capital tracker revenue collected for this project in 2013 on a forecast basis was refunded to customers. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application.

319. The Commission observes that the K factor revenue requirement calculation for the Distribution Pole and Aerial Line Life Cycle Replacement project proposed for 2016 and 2017 incorporates the 2013 and 2014 actual capital additions for this project, that were incurred under the I-X mechanism prior to requesting capital tracker treatment, and forecast capital additions for 2015. As explained in Section 3 of this decision, in the absence of any evidence that the 2013 to 2015 capital additions for this project incurred under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

320. In the present application, EPCOR requested capital tracker treatment for this project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker

³⁴³ Exhibit 20407-X0110, Appendix A-6, paragraph 43, also clarified in Exhibit 20407-X0146, EDTI-AUC-2015JUN26-027(b), and corrected in Exhibit 20407-X0192, paragraph 5.

³⁴⁴ Exhibit 20407-X0110, Appendix A-6, paragraph 59, also clarified in Exhibit 20407-X0146, EDTI-AUC-2015JUN26-027(b).

³⁴⁵ Transcript, Volume 3, page 401, lines 15-22 (Ms. Hull).

³⁴⁶ Decision 2013-435, paragraph 890.

³⁴⁷ Decision 3100-D01-2015, paragraph 287.

³⁴⁸ Decision 20210-D01-2015, paragraph 9 and Table 2 on page 3.

treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Distribution Pole and Aerial Line Life Cycle Replacement project is not required to continue in 2016 or 2017.

321. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are \$3.62 million in 2016 and 4.15 million in 2017. The Commission is satisfied with EPCOR's explanation that five-kV circuits are upgraded as part of this project only when they are identified as requiring replacement under its inspection program. The Commission accepts that no five-kV circuits are upgraded under this program solely to achieve an upgrade to 15 kV.³⁴⁹ The Commission also observes that the 2016 and 2017 forecast costs for each of these projects or programs are generally consistent with the variance explanations provided in the business case for the actual expenditures over the most recent five-year period. EPCOR's 2016 and 2017 forecast costs are reflective of cost efficiencies achieved for this project in 2014, given the three-year normalized average forecasting methodology.³⁵⁰ The Commission has reviewed the information supporting EPCOR's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable based on current and historical inspection results and a three-year normalized average total combined unit pole cost,³⁵¹ subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

322. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Distribution Pole and Aerial Line Life Cycle Replacement project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.2.5 New Underground and Aerial Service Connections for Commercial, Industrial, Multi-family and Miscellaneous Customers

323. This ongoing growth project consists of the engineering and installation of the distribution facilities necessary to connect new industrial, commercial, multi-family, unmetered secondary and rural customers to EPCOR's distribution system. This project also includes increasing the capacity of, and upgrading existing service connections when requested by these types of customers.³⁵² EPCOR noted that this project was approved for capital tracker treatment in Decision 2013-435 for 2013 and in Decision 3100-D01-2015 for 2014-2015.³⁵³ EPCOR provided a business case and an engineering study for the New Underground and Aerial Service

³⁴⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-026(a).

³⁵⁰ Exhibit 20407-X0110, Appendix A-6, paragraph 59 and Transcript, Volume 3, page 401, lines 15-22 (Ms. Hull).

³⁵¹ Exhibit 20407-X0110, Appendix A-6, paragraphs 40-43.

³⁵² Exhibit 20407-X0130.02, revised application, paragraph 340.

³⁵³ Exhibit 20407-X0130.02, revised application, paragraph 341.

Connections for Commercial, Industrial, Multi-Family and Miscellaneous Customers project in Appendix A-5 of the application.

324. EPCOR indicated that service connections are installed in accordance with its Customer Connection Guide, and the use of aerial versus underground services is determined on a site-by-site basis. The appropriate service type is dictated by City of Edmonton bylaws, policies and land use planning requirements, the specific circumstances surrounding the site, the customer's requirements at the site, and any other applicable regulations, standards or codes.³⁵⁴

325. The 2014 approved forecast capital additions for this project were \$9.17 million, based on the normalized three-year average of 2011 to 2013 historical actual annual costs.³⁵⁵ EPCOR's actual capital additions for this project for 2014 were \$10.80 million, for a positive variance of \$1.63 million.³⁵⁶ EPCOR explained that the \$1.63 million increase in capital additions in 2014 was primarily related to a higher than forecast volume of customer service connections being requested and installed in 2014. EPCOR indicated that it was required to install 607 customer service connections in 2014, rather than 512 customer service connections forecast for that year.³⁵⁷

326. Regarding the prudence of its actual 2014 capital additions, EPCOR confirmed that the 2014 work on this project was completed in accordance with its formal project management policies and procedures, as described in the application, and the costs included in this project consisted of engineering (23 per cent), material (31 per cent) and construction (46 per cent) costs. EPCOR described the steps it took to ensure that the work was completed in a cost effective manner.³⁵⁸

327. EPCOR confirmed that "nothing occurred between the date of EDTI's 2014 Tracker Application and the work completed in 2014 that obviated the need for this project, or that would have materially impacted the conclusions reached in EDTI's analysis of alternatives."³⁵⁹

328. In response to a Commission IR EDTI-AUC-2015JUN26-025, EPCOR provided an update to Table 3.2-2 of Appendix A-5 and corrected an error in the 2016 and 2017 forecasts. EPCOR further explained that any inconsistency between the forecast cost and the three-year historical average cost per underground and aerial service connection is resolved when the escalation factors are considered in the historical results and the averages normalized.³⁶⁰ In an undertaking to the Commission, EPCOR provided an update to the 2016 and 2017 forecast numbers to reflect the changes made in response to the referenced IR EDTI-AUC-2015JUN26-025.

329. Based on these revisions, EPCOR's forecast capital additions associated with this project were \$11.34 million in 2016 and \$11.68 million in 2017.³⁶¹ EPCOR stated that capital

³⁵⁴ Exhibit 20407-X0111, Appendix A-5, paragraph 4.

³⁵⁵ Decision 20210-D01-2015, Table 3 K factor based on capital additions in Exhibit 20210-X0004, Schedule 3.

³⁵⁶ Exhibit 20407-X0130.02, revised application, paragraph 887.

³⁵⁷ Exhibit 20407-X0111, Appendix A-5, paragraph 46.

³⁵⁸ Exhibit 20407-X0130.02, revised application, paragraphs 889-898.

³⁵⁹ Exhibit 20407-X0130.02, revised application, paragraph 886.

³⁶⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-025(a) and (b), Table EDTI-AUC-2015JUN26-025-1.

³⁶¹ Exhibit 20407-X0200, Undertaking 200.

expenditures for this project are primarily driven by the number of connection requests received and the type of customer service connections installed in a given year.³⁶² EPCOR explained that for this project, it used a normalized three-year average of the 2012 to 2014 historical actual annual costs. EPCOR further noted that the Commission found the use of a three-year normalized cost forecasting methodology to be reasonable in Decision 2012-272,³⁶³ and in Decision 3100-D01-2015.³⁶⁴

330. Neither the UCA nor the CCA commented on the New Underground and Aerial Service Connections for Commercial, Industrial, Multi-Family and Miscellaneous Customers project in their respective arguments and reply arguments.

Commission findings

331. In Decision 2013-435,³⁶⁵ and later in Decision 3100-D01-2015,³⁶⁶ the Commission approved the need for the New Underground and Aerial Service Connections for Commercial, Industrial, Multi-family and Miscellaneous Customers project for purposes of capital tracker treatment for 2013 and 2014-2015, respectively. Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1. In addition, in Decision 3100-D01-2015 and the compliance filing Decision 20210-D01-2015 in relation thereto, the Commission approved the actual scope, level, timing and costs of this project, included in the 2013 capital tracker true-up application, as prudent.

332. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the New Underground and Aerial Service Connections for Commercial, Industrial, Multi-family and Miscellaneous Customers project was not required in 2014.

333. With respect to the scope, level and timing of the project carried out in 2014, the Commission has reviewed EPCOR's 2014 actual capital additions of \$10.80 million associated with this project and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for this capital tracker and approved in Decision 3100-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

³⁶² Exhibit 20407-X0111, Appendix A-5, paragraph 28.

³⁶³ Decision 2012-272: EPCOR Distribution & Transmission Inc., 2012 Phase I and II Distribution Tariff, 2012 Transmission Facility Owner Tariff, Proceeding 1596, Application 1607944-1, October 5, 2012.

³⁶⁴ Exhibit 20407-X0111, Appendix A-5, paragraph 29.

³⁶⁵ Decision 2013-435, paragraph 919.

³⁶⁶ Decision 3100-D01-2015, paragraph 356.

334. In the present application, EPCOR also requested capital tracker treatment for this project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the New Underground and Aerial Service Connections for Commercial, Industrial, Multi-Family and Miscellaneous Customers project is not required to continue in 2016 or 2017.

335. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are \$11.34 million in 2016 and \$11.68 million in 2017.³⁶⁷ The Commission observes that the 2016 and 2017 forecast costs for this project are generally consistent with the variance explanations provided in the business case for the actual expenditures over the most recent five-year period. The Commission found EPCOR's normalized three-year average cost forecasting methodology to be reasonable in Decision 2012-272.³⁶⁸ The Commission has reviewed the information supporting EPCOR's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable based on the normalized three-year average of 2012 to 2014 historical actual annual costs subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

336. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the New Underground and Aerial Service Connections for Commercial, Industrial, Multi-Family and Miscellaneous Customers project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.2.6 Poundmaker Feeders

337. The Poundmaker Feeders project, approved by the Commission in Decision 2012-272, involved the construction of four feeders from EPCOR's new point of delivery at its Poundmaker substation located in west Edmonton. This project was completed over the 2011 to 2013 period. The need for this project under the project assessment requirement of Criterion 1 for capital tracker treatment was approved in Decision 2013-435.³⁶⁹ In Decision 3100-D01-2015, the Commission determined that the actual scope, level and timing of the work for the Poundmaker Feeders project and the actual costs in each of 2011, 2012 and 2013, totalling \$11.47 million, were prudent.³⁷⁰

³⁶⁷ Exhibit 20407-X0200, Undertaking 200.

³⁶⁸ Decision 2012-272, paragraphs 232-233.

³⁶⁹ Decision 2013-435, paragraph 935.

³⁷⁰ Decision 3100-D01-2015, paragraph 425.

338. As explained in Decision 2013-435, the Poundmaker Feeders project is an example of EPCOR's "Category 3" projects that require capital tracker treatment because of the application of the mid-year convention. The application of the mid-year convention calculation in the determination of return and depreciation with respect to projects going into service in the year prior to the commencement of PBR may cause a shortfall in capital funding under the PBR formula.³⁷¹ As such, even though there are no capital additions forecast for the Poundmaker Feeders project in either 2016 or 2017, EPCOR applied for capital tracker treatment for this project because of the shortfall in capital funding under the PBR formula.

339. In a similar vein, EPCOR also included the Poundmaker Feeders project in the 2014 capital tracker true-up, even though there were no capital additions for this project in 2014. As set out in Table 1 at Section 4 of this decision, the 2014 approved forecast K factor portion associated with this project was \$0.56 million, while the 2014 actual K factor portion was \$0.52 million. In response to a Commission IR, EPCOR explained that the \$0.04 million negative variance between forecast and actual 2014 K factor amounts arose due the difference between the actual and forecast revenue requirement incurred, driven by the 2014 forecast WACC rate (6.78 per cent) being higher than the 2014 actual WACC rate (6.50 per cent), because of a lower than forecast actual cost of debt.³⁷²

Commission findings

340. The Poundmaker Feeders project was approved by the Commission in Decision 2012-272. In Decision 2013-435³⁷³ and later in Decision 3100-D01-2015,³⁷⁴ the Commission determined that this project satisfied the project assessment requirement under Criterion 1. In Decision 3100-D01-2015, the Commission also determined that the actual scope, level and timing of the work for the Poundmaker Feeders project and the actual costs incurred in each of 2011, 2012 and 2013, totalling \$11.47 million, were prudent.

341. Because the Poundmaker Feeders project was completed in 2013, there are no capital additions for this project for the remaining 2014 to 2017 years of the current PBR term. As such, there is no need for the Commission in this proceeding to re-evaluate either the need for the project, or the prudence of the scope, level and timing of the project and associated costs as part of project assessment under Criterion 1.

342. As set out earlier in this section, Category 3 projects would receive capital tracker treatment when the revenue provided under the I-X mechanism is not sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for this project. For a completed Category 3 project, the K factor amount associated with such a project becomes a function of the accounting test and materiality test calculations. The Commission has to verify that the revenue requirement calculations for a Category 3 project in the accounting test are based on the approved actual capital additions for the project. The Commission would still undertake a project assessment for any Category 3 project, for which the actual costs were not approved by the Commission. Once Category 3 projects are approved as satisfying Criterion 2 in a given year, no further Criterion 2 approvals are required to continue the project as a capital

³⁷¹ Decision 2013-435, paragraph 932.

³⁷² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-035(a).

³⁷³ Decision 40713-435, paragraph 935.

³⁷⁴ Decision 3100-D01-2015, paragraph 425.

tracker. Criterion 3 requirements, however, must be satisfied for each forecast year and in each true-up application.

343. The Poundmaker Feeders project is the only Category 3 project included in EPCOR's capital tracker 2014 true-up and 2016-2017 forecast.³⁷⁵ With respect to the 2014 true-up, EPCOR explained that the reason for the \$0.04 million variance between the actual Poundmaker Feeders project component of the 2014 K factor and the approved forecast Poundmaker Feeders project component of the 2014 K factor for this project is the difference between the actual and forecast revenue requirement incurred due to a lower than forecast actual cost of debt.³⁷⁶ The Commission has reviewed and accepted these variance adjustments and approves the proposed 2014 true-up adjustment to the Poundmaker Feeders project component of the K factor. With regard to the 2016 and 2017 forecasts, the Commission verified that EPCOR's forecast revenue shortfall for the Poundmaker Feeders project in each of those years is based on the 2011 to 2013 actual capital additions for this project, which the Commission found to be prudent in Decision 3100-D01-2015.

344. As set out in Section 7.1 of this decision, the Commission has reviewed EPCOR's accounting test calculations and finds them to be reasonable. Accordingly, the Commission approves the applied-for forecast 2016 and 2017 K factor portions associated with the Poundmaker Feeders project, subject to final Commission approval of the accounting test and Criterion 3 materiality test calculations for this project in the compliance filing.

6.2.7 OMS/DMS Life Cycle Replacement

345. This project consists of replacing the obsolete technology and systems used in EPCOR's Control Operations center. Currently, EPCOR's distribution and transmission systems are operated using paper documentation and processes, an obsolete outage tracking system, and an obsolete mimic board. EPCOR stated that the replacement of its current system to an industry-standard automated OMS/DMS is required to continue to operate its distribution systems in a safe, reliable and efficient manner.³⁷⁷ EPCOR noted that this project was approved as a capital tracker for 2015 in Decision 3100-D01-2015.³⁷⁸ EPCOR provided a business case for the OMS/DMS life cycle replacement project in Appendix A-18 of its application.

346. As noted in Decision 3100-D01-2015, EPCOR requested capital tracker treatment for this project in 2015 only, because the project did not have any capital additions in prior years. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in this application.

347. In its 2014-2015 capital tracker application, EPCOR applied for \$9.09 million in forecast capital additions in 2015 for this project. In that application, EPCOR estimated the total forecast project cost for the OMS/DMS project was \$12.1 million and EPCOR expected the remainder of

³⁷⁵ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-035(a).

³⁷⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-035(a).

³⁷⁷ Exhibit 20407-X0083, Appendix A-18, paragraph 1.

³⁷⁸ Exhibit 20407-X0083, Appendix A-18, paragraph 2.

the capital additions to be incurred in 2016. In Decision 3100-D01-2015, the Commission found the forecast \$9.09 million in capital additions for 2015 to be reasonable.³⁷⁹

348. In this application, EPCOR forecast the total cost of the OMS/DMS replacement project to be \$14.50 million, which represents a \$2.4 million positive variance over the previously estimated total project cost provided in the 2014-2015 capital tracker application. Furthermore, the project completion date is now expected to be 2017. EPCOR explained that the DMS portion of the project will be placed into service by the end of 2015, but the OMS portion is not expected to be in service until the first quarter of 2017. EPCOR's expectation was that \$9.09 million in capital additions will be added in 2015 and the remaining \$5.41 million added in 2017.³⁸⁰ As a result, EPCOR applied for capital tracker treatment of \$5.41 million in capital additions for 2017, and will bring forward its 2015 actuals in its 2015 capital tracker true-up application.

349. EPCOR explained that the \$2.4 million positive variance in the total project cost between the last capital tracker application and the current application is due to three components. First, \$1.33 million of the variance is a result of the need for upgrades to EPCOR's control system server room. Specifically, upgrades are required to the air conditioning, air containment, airflow, and power distribution systems.³⁸¹ EPCOR's engineering firm completed an assessment of the project costs and provided the \$1.33 million estimate for the upgrades.³⁸² Three options were considered by the engineering firm to address the air conditioning issues in the control server room: install rack cooling; install wall mounted air conditioning; install traditional ducted air conditioning. EPCOR explained that:

The wall mounted and traditional duct air conditioning options were not feasible as they would require significant structural changes to the building in order to expand the room to accommodate the options. The in rack cooling option, which runs coolant through the rack in which the servers are installed, was selected and EPCOR's contracted data centre electrical vendor partnered with the data centre engineering firm to finalize the design and plan for the control server room upgrades. From initial to final design, EDTI reviewed the plans at each step to validate and confirm the necessity and cost competitiveness of each component of the design being proposed. The final design was approved by EDTI and the construction was started.³⁸³

350. During the hearing, Mr. Baraniecki confirmed that the in-rack cooling option was estimated to be the least cost option given that no structural changes were required.³⁸⁴

351. The second component contributing to the variance in the total project cost is \$0.6 million for the purchase of updated control system backup software, given that the current backup system would not be compliant with the new OMS/DMS.³⁸⁵ EPCOR considered two alternatives, the Networker back up and the NetBackup solution, both of which had comparable

³⁷⁹ Decision 3100-D01-2015, paragraph 443.

³⁸⁰ Exhibit 20407-X0083, Appendix A-18, paragraphs 3-4.

³⁸¹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-036(a).

³⁸² Exhibit 20407-X0083, Appendix A-18, paragraph 32.

³⁸³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-037(a).

³⁸⁴ Transcript, Volume 3, page 383, line 20 to page 384, line 7 (Mr. Baraniecki).

³⁸⁵ Exhibit 20407-X0083, Appendix A-18, paragraph 33.

costs and chose the former, given EPCOR's experience with the technology and industry reviews.³⁸⁶

352. The final component comprising the total project cost variance is a \$0.47 million increase caused by the requirement for further business analysis, development and testing of the OMS system. Specifically, EPCOR's geographic information system, engineering standards, and design methods need to be aligned with the requirements of the OMS system. EPCOR stated that the additional analysis, development, and testing were recognized during the design workshops that occurred after the previous forecast was submitted in Proceeding 3100.³⁸⁷

353. Mr. Reimer explained that at the time of the hearing, EPCOR was not expecting any further cost increases for this project.³⁸⁸ Mr. Baraniecki added that the OMS/DMS project is the subject of additional oversight meetings by EPCOR's steering committee, which includes its senior vice president. These meetings are in addition to EPCOR's normal project management activities, described in Section 6.1.4. The steering committee will provide oversight on the scope, timing and budget of the project.³⁸⁹

354. Neither the UCA nor the CCA commented on the OMS/DMS Life Cycle Replacement project in their respective arguments and reply arguments.

Commission findings

355. In Decision 3100-D01-2015,³⁹⁰ the Commission approved the need for the OMS/DMS Life Cycle Replacement project for purposes of capital tracker treatment for 2015. Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1.

356. In its 2014-2015 capital tracker forecast application, EPCOR did not request capital tracker treatment for this project in 2014, because the project did not have forecast capital additions in 2014. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application because there were no capital additions for this project in 2014. EPCOR did, however, apply for and receive capital tracker treatment for this project in 2015.

357. In the present application, EPCOR also requested capital tracker treatment for this project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the OMS/DMS Life Cycle Replacement project is not required to continue in 2016 and 2017.

³⁸⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-037(a).

³⁸⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-036(a).

³⁸⁸ Transcript, Volume 3, page 385, lines 12-13 (Mr. Reimer).

³⁸⁹ Transcript, Volume 3, page 386, lines 2-18 (Mr. Baraniecki).

³⁹⁰ Decision 3100-D01-2015, paragraph 444.

358. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable.

359. EPCOR did not forecast any capital additions for 2016 for the OMS/DMS Life Cycle Replacement project. However, EPCOR requested capital tracker treatment for this project for 2016 because of the shortfall in capital funding under the PBR formula. As further explained in Section 6.2.8, in this case, the treatment of the OMS/DMS Life Cycle Replacement project on a forecast basis in 2016 is similar to EPCOR's Category 3 projects, which would receive capital tracker treatment when the revenue provided under the I-X mechanism is not sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for a project. With regard to the 2016 forecast, the Commission verified that EPCOR's forecast revenue shortfall for the OMS/DMS Life Cycle Replacement project in 2016 is based on the 2015 forecast capital additions for this project which the Commission approved in Decision 3100-D01-2015.³⁹¹

360. EPCOR's forecast capital additions associated with this project are \$5.41 million in 2017. The Commission is satisfied with EPCOR's explanation of the increase in forecast project costs based on the additional analysis, development, and testing completed as the project progressed. The Commission has reviewed the information supporting EPCOR's 2017 forecasts and finds the total annual cost forecasts to be reasonable based on the project summary and cost minimization measures provided in the business case,³⁹² subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

361. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the OMS/DMS Life Cycle Replacement project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

362. In Section 6.1.5, the Commission approved an AUF for this project in 2017 of \$0.04 million. As explained in that section, the AUF is paid by EPCOR's transmission function to its distribution function for the joint use of an asset, and is an offset to the K factor associated with this project.

6.2.8 Neighbourhood Renewal program

363. This ongoing program contemplates the replacement of a large portion of EPCOR's electric distribution infrastructure within identified aging neighbourhoods. EPCOR noted that this project was approved as a capital tracker in Decision 3100-D01-2015 for 2014 and 2015. This project was also approved in prior decisions dealing with EPCOR's cost-of-service tariff applications. EPCOR provided a copy of its Neighbourhood Renewal business case and engineering study submitted in its 2014-2015 capital tracker forecast application as

³⁹¹ Decision 3100-D01-2015, paragraph 443.

³⁹² Exhibit 20407-X0083, Appendix A-18, paragraphs 35-37.

Appendix B-17 of this application. The need for this program as part of the project assessment under capital tracker Criterion 1, was approved in Decision 3100-D01-2015³⁹³ for 2014 and 2015.

364. The 2014 approved forecast capital additions for this program were \$0.28 million, to complete the Lansdowne neighbourhood renewal project. The actual 2014 capital additions for this project were \$0.54 million, for a positive variance of \$0.26 million. EPCOR explained that the \$0.26 million variance to forecast was due to an unanticipated \$0.17 million invoice received from a contractor in 2014 for work completed in 2013, and a \$0.09 million increase in labour and overtime costs.³⁹⁴ At the oral hearing, EPCOR further explained that the variance related to the invoice was due to project manager error and confirmed that this was “definitely part of that project manager’s performance review.”³⁹⁵

365. Regarding the prudence of its actual 2014 capital additions, EPCOR confirmed that the 2014 work on this project was completed in accordance with its formal project management policies and procedures, as described in the application, and the costs included in this project consisted of material (20 per cent) and construction (80 per cent) costs. EPCOR described the steps it took to ensure that the work was completed in a cost effective manner.³⁹⁶

366. EPCOR confirmed that “nothing occurred between the date of EDTI’s 2014 Tracker Application and the work completed in 2014 that obviated the need for this project, or that would have materially impacted the conclusions reached in EDTI’s analysis of alternatives.”³⁹⁷

367. EPCOR did not forecast any capital additions for this program for 2016 and 2017 but did request capital tracker treatment in 2016 and 2017 associated with the funding shortfall for capital tracker projects undertaken in 2013 and 2014.³⁹⁸ Because no new capital additions were planned for 2016 and 2017, EPCOR did not provide an updated business case and engineering study for this program. EPCOR did provide, however, a copy of its Neighbourhood Renewal business case and engineering study submitted in its 2014-2015 capital tracker forecast application as Appendix B-17 of this application.

368. As set out in Appendix B-17, in early 2012, EPCOR reviewed the condition of the underground distribution assets in the Duggan neighbourhood and concluded that it was “necessary and prudent” to complete a rehabilitation of EPCOR facilities in the area. EPCOR planned to commence the project in 2014, with the majority of capital expenditures occurring in the 2016 to 2019 time period, spreading the work over an “appropriate period.”³⁹⁹

369. In response to a Commission IR, EPCOR explained that it had decided to defer the Duggan neighbourhood renewal project to develop further the decision criteria for neighbourhood renewal projects, which would be based on industry best practices for asset management. EPCOR noted that it is in the process of redefining its distribution asset maintenance/replacement strategy and planning criteria. In the meantime, EPCOR stated that it

³⁹³ Decision 3100-D01-2015, paragraph 501.

³⁹⁴ Exhibit 20407-X0130.02, revised application, paragraphs 1081 and 1094.

³⁹⁵ Transcript, Volume 2, page 344, lines 2-7 (Ms. Hull).

³⁹⁶ Exhibit 20407-X0130.02, revised application, paragraphs 1084-1093.

³⁹⁷ Exhibit 20407-X0130.02, revised application, paragraph 1080.

³⁹⁸ Exhibit 20407-X0130.02, revised application, paragraph 553.

³⁹⁹ Exhibit 20407-X0015, Appendix B-17, paragraphs 11-17.

“will monitor service quality in Duggan and will address any potential or emerging issues through a specific Life Cycle Replacement project,”⁴⁰⁰ either a cable life cycle replacement project or a replacement project.⁴⁰¹ When questioned by Commission counsel regarding EPCOR’s reasoning to maintain a separate neighbourhood renewal program as opposed to disaggregating all the neighbourhood renewal projects into their specific life cycle replacement projects, EPCOR confirmed that the “approach to look at all assets together is still sound,” and there are “efficiencies to be gained when you go in and you do a whole neighbourhood.”⁴⁰²

370. During the oral hearing, Ms. Hull stated that EPCOR had deferred the Duggan project because it had identified other neighbourhoods with higher failure rates and more outages.⁴⁰³ Ms. Hull clarified the reasons that allowed EPCOR to reassess the timing of the replacement of facilities in the Duggan neighbourhood since Proceeding 3100:

MS. HULL: What’s happened since is we have better information. We have more information on how our system’s performing. And as I was speaking with Mr. McNulty this morning, we’re able to mine the data out of our systems that the Commission has approved in the recent past, our GIS system, our SOLAR system, our IVARA, or our work management system, overlay those together with what’s happening out in our system to make better informed decisions since the forecast was put together for Duggan.⁴⁰⁴

371. When asked to confirm the forecast of zero capital additions for this program for 2016 and 2017, Ms. Hull stated “if we go ahead with renewing the neighbourhood in the north, we’ll bring it forward on a true-up basis.”⁴⁰⁵

372. Intervenors did not raise any concerns with the 2014 capital tracker true-up for the Neighbourhood Renewal program. However, the UCA submitted that capital tracker treatment for this program in 2016 and 2017 should be denied for the following reasons, as stated in its argument:

... EDTI has not identified any specific projects under this program, and is essentially requesting Capital Tracker treatment on a “bucket of costs” basis. The UCA asserts that this is inappropriate and fails to meet the criteria for Capital Tracker treatment.⁴⁰⁶

373. While the UCA did not challenge EPCOR’s 2014 actual costs for the Neighbourhood Renewal program, the UCA challenged whether this program currently satisfies the requirements under Criterion 1, considering EPCOR did not propose any capital expenditures for 2016 and 2017:

... given that no specific neighbourhood renewal projects are forecast, it is impossible to conclude that the Neighbourhood Renewal Program meets Criterion 1. EDTI is, essentially, requesting approval of a “bucket of costs” without any evidence as to how it

⁴⁰⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-042.

⁴⁰¹ Transcript, Volume 2, page 338, lines 2-4 (Ms. Hull).

⁴⁰² Transcript, Volume 2, page 338, lines 19-22 (Ms. Hull).

⁴⁰³ Transcript, Volume 2, page 339, lines 1-12 (Ms. Hull).

⁴⁰⁴ Transcript, Volume 2, page 334, line 23 to page 335, line 7 (Ms. Hull).

⁴⁰⁵ Transcript, Volume 2, page 340, lines 7-9 (Ms. Hull).

⁴⁰⁶ Exhibit 20407-X0232, UCA argument, paragraph 4c.

proposes to use it, or whether the amount requested is required to prevent deterioration in service quality and safety.⁴⁰⁷

... the Neighbourhood Renewal Program is of a different nature than life cycle replacement projects such as emergency replacement of equipment. Projects under the Neighbourhood Renewal Program typically have a known scope, such as the now-postponed Duggan project, and are planned in advance in accordance with EDTI's asset management practices that determine priority....⁴⁰⁸

Commission findings

374. In Decision 3100-D01-2015,⁴⁰⁹ the Commission approved the need for the Neighbourhood Renewal program for purposes of capital tracker treatment for 2013 and 2014-2015. Further, the Commission determined that the proposed scope, level, timing and forecast costs for this program were reasonable. Therefore, the Commission has previously determined that this program satisfied the project assessment requirement of Criterion 1. In addition, in Decision 3100-D01-2015 and the compliance filing Decision 20210-D01-2015 in relation thereto, the Commission approved the actual scope, level, timing and costs of this program, included in the 2013 capital tracker true-up application, as prudent.

375. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. No party challenged the need for the project in 2014. The Commission does not find sufficient evidence on the record of this proceeding to indicate that the Neighbourhood Renewal program was not required in 2014.

376. No party challenged the scope, level, timing and costs of the Neighbourhood Renewal program carried out in 2014. The Commission has reviewed EPCOR's 2014 actual capital additions of \$0.54 million associated with this program and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for this capital tracker and approved in Decision 3100-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this program in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

377. In the present application, EPCOR did not forecast any capital additions for 2016 and 2017 for the Neighbourhood Renewal program. However, EPCOR requested capital tracker treatment for this program for 2016 and 2017, because of the shortfall in capital funding under the PBR formula for Neighbourhood Renewal projects provided capital tracker treatment in 2013 and 2014. The Commission does not agree with the UCA's conclusion that the Neighbourhood Renewal program does not meet the capital tracker criteria for 2016 and 2017 because EPCOR

⁴⁰⁷ Exhibit 20407-X0232, UCA argument, paragraph 73.

⁴⁰⁸ Exhibit 20407-X0236, UCA reply argument, paragraph 5.

⁴⁰⁹ Decision 3100-D01-2015, paragraph 501.

did not forecast any projects for this time period. The 2013 and 2014 Neighbourhood Renewal capital tracker capital additions have been found by the Commission to have satisfied the capital tracker criteria, including the need for the project, and the costs incurred in those years have been determined prudent. The Commission observes that in this case, the treatment of the Neighbourhood Renewal program on a forecast basis in 2016 and 2017 is similar to EPCOR's Category 3 projects, which would receive capital tracker treatment when the revenue provided under the I-X mechanism is not sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for a project.

378. Because the K factor portion associated with this program is calculated based on prudent capital expenditures for the program, rather than future expenditures, the K factor amount associated with this program becomes a function of the accounting test and materiality test calculations. Subject to verifying that the revenue requirement calculations for this program in the accounting test, are based on the approved actual capital additions for the program, there is no need for the Commission in this proceeding to re-evaluate either the need for the program in 2016 or 2017, or the reasonableness of the scope, level and timing and associated 2016 and 2017 forecast costs as part of project assessment under Criterion 1. Criterion 3 requirements, however, must be satisfied for each forecast year and in each true-up application.

379. With regard to the 2016 and 2017 forecasts, the Commission verified that EPCOR's forecast revenue shortfall for the Neighbourhood Renewal program in each of those years is based on prudent capital expenditures for the program, up to and including the 2014 actual expenditures, which the Commission approved earlier in this section. EPCOR's accounting test for 2016 and 2017 demonstrates that the revenue from the I-X mechanism is insufficient to fund a portion of the revenue requirement associated with the overall capital expenditures for the Neighbourhood Renewal program.

380. As set out in Section 7.1 of this decision, the Commission has reviewed EPCOR's accounting test calculations and finds them to be reasonable. Accordingly, the Commission approves the applied-for forecast 2016 and 2017 K factor portions associated with the Neighbourhood Renewal program, subject to final Commission approval of the accounting test and Criterion 3 materiality test calculations for this program in the compliance filing.

381. While EPCOR may apply for capital tracker treatment of actual capital expenditures made in 2016 and 2017 associated with this program on a true-up basis, given that EPCOR is in the process of redefining its distribution asset maintenance/replacement strategy and planning criteria for this program,⁴¹⁰ any such application would require evidence to re-establish the need for any projects undertaken as part of the Neighbourhood Renewal program in 2016 and 2017. As well, EPCOR will be required to provide evidence demonstrating that the actual scope, level, timing and the costs incurred for the program for 2016 and 2017 were prudent.

6.2.9 Life Cycle Replacement of PILC Cable Systems

382. This ongoing project consists of the planned replacement of EPCOR's medium voltage (five- to 15-kV rated) PILC underground distribution cables and PILC cable accessories, which have reached the end of their useful lives.⁴¹¹ EPCOR noted that the Commission reviewed this

⁴¹⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-042(a).

⁴¹¹ Exhibit 20407-X0130.02, revised application, paragraph 519.

project in Decision 2013-435 and found that the project satisfied Criterion 1.⁴¹² The project did not, however, satisfy the first tier capital tracker materiality threshold and, as such, the project was not approved as a capital tracker for 2013, but it was subsequently approved in Decision 3100-D01-2015 as a capital tracker for 2015.⁴¹³ EPCOR provided a business case and an engineering study for the Life Cycle Replacement of PILC Cable Systems project in Appendix A-17 of the application.

383. EPCOR continued this project in 2014; however, it did not meet the first tier materiality threshold for 2014 on a forecast basis.⁴¹⁴ EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in this application.

384. EPCOR explained that the average service life of EPCOR's PILC cables for depreciation purposes was 40 years, and approximately 30 per cent of the total length of PILC cables installed on EPCOR's underground distribution system were older than 40 years.⁴¹⁵

385. This project was initiated following EPCOR's review of the significant increase in the number of customer hours of interruption it experienced in 2011 due to PILC cable system failures.⁴¹⁶ EPCOR further explained in its application that in 2015, it revised its distribution system failure rate model incorporating the actual PILC cable failure rate data from 2008 to 2014, following a significant increase in the number of PILC cable failures experienced in 2014. The volume of cable planned for replacement in the 2016 to 2017 period was based on a forecast of customer hours of interruption associated with the updated failure rates of the installed PILC cables in EPCOR's radial distribution system.⁴¹⁷

386. EPCOR further stated that based on the updated cable failure model, EPCOR determined that in order to continue providing reliable distribution system service, the forecast length of PILC cables that should proactively be replaced each year should be increased by one km per year in each of 2015, 2016 and 2017, with approximately 24.4 km of PILC cable targeted to be replaced over the 2013 to 2017 period.⁴¹⁸ EPCOR explained that, to minimize costs, its PILC cable failure rate model was developed internally using the same methodology as the KEMA report, for modelling underground cable failure rates (discussed in Section 6.2.2 of this decision).⁴¹⁹

387. EPCOR forecast capital additions associated with this project to be \$2.23 million in 2016 and \$2.28 million in 2017.⁴²⁰ EPCOR stated that it selects PILC cables for replacement based on cable condition assessments, including cable insulation voltage withstand testing.⁴²¹ EPCOR further explained that its 2016 and 2017 forecast capital additions for this project were based on the forecast length of PILC cable planned to be replaced each year, multiplied by historical unit

⁴¹² Decision 2013-435, paragraph 868.

⁴¹³ Exhibit 20407-X0130.02, revised application, paragraph 522.

⁴¹⁴ Decision 3100-D01-2015, paragraph 559.

⁴¹⁵ Exhibit 20407-X0087, Appendix A-17, paragraph 2.

⁴¹⁶ Exhibit 20407-X0130.02, revised application, paragraph 529.

⁴¹⁷ Exhibit 20407-X0087, Appendix A-17, paragraph 6.

⁴¹⁸ Exhibit 20407-X0087, Appendix A-17, paragraphs 8 and 60.

⁴¹⁹ Transcript, Volume 2, page 259 line 8 to page 260, line 8 (Ms. Hull).

⁴²⁰ Exhibit 20407-X0087, Appendix A-17, paragraph 4.

⁴²¹ Exhibit 20407-X0087, Appendix A-17, paragraph 9.

cost (cost per kilometer) for replacing PILC cable with TR-XLPE, a polyethylene insulated cable, based on EPCOR's historical actual costs with respect to PILC cable replacements carried out between 2010 and 2012.⁴²²

388. In response to a Commission IR, EPCOR confirmed that no causes other than age related deterioration were identified for the increased cable failures in the years 2011 and 2014. EPCOR explained that its engineers determined that PILC cable failures in 2011 and 2014 related to moisture ingress into the insulation, or the insulation paper containing insufficient oil, causing accelerated aging of cable until it failed.⁴²³

389. In an IR response with respect to the Commission's questions on reliability of PILC cables, EPCOR stated that it is unaware of any regulations specific to the use or installation of PILC cable in North America. However, EPCOR pointed out that this project is consistent with the work undertaken by other utilities in North America and referenced Toronto Hydro and Con Edison that have implemented programs to replace all PILC cables in their systems.⁴²⁴

390. During the hearing, the Commission queried EPCOR on the soundness, predictive power and the resulting informational value of EPCOR's PILC cable failure rate model, on which the number of kilometers of cable planned for replacement was based. The Commission also sought further clarification on the sensitivity of the model, specifically how PILC cable faults and replacements affect reliability indicators such as SAIDI and SAIFI. In an undertaking to the Commission, EPCOR provided plots of the measured data and the fitted curves produced by its model used in planning for PILC cable replacements.⁴²⁵ Mr. Baraniecki acknowledged in the oral hearing that, as any statistical model, EPCOR's PILC cable failure rate model has its limitations and could benefit from performing a sensitivity analysis on the obtained results:

...But I, too, went through the KEMA report this weekend, and I agree with you -- or at least where I think you're -- what you're saying is we see, well, one statistical measure. It's basically only one statistical measure that says, this curve fits this data better than that curve, but it doesn't tell us any other information than that. Well -- and, specifically, is it really actually that good of a curve? All it says is really is one curve better than the other? So we're sitting here learning from these exchanges. And as Ms. Hull mentioned last week, we are in the process of doing an RFP for an update of this information, and we'll probably try to get the PILC information -- or cables in there too. And we're going to be asking for more, you know, of this backup data so we can see the type of things that you suggesting. That actually makes a lot of sense to me of, you know, understanding really the ability to have sensitivity analysis on this...⁴²⁶

391. In a similar vein, Ms. Hull also commented that "maybe this is the time to roll in PILC with that RFP for cable as a whole as we go out this year."⁴²⁷

⁴²² Exhibit 20407-X0087, Appendix A-17, paragraph 64.

⁴²³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-047(a).

⁴²⁴ Exhibit 20407-X0087, Appendix A-17, paragraph 54.

⁴²⁵ Exhibit 20407-X0198, Undertaking 198.

⁴²⁶ Transcript, Volume 3, page 369, lines 6-25 (Mr. Baraniecki).

⁴²⁷ Transcript, Volume 2, page 264 lines 17-19 (Ms. Hull).

392. Neither the UCA nor the CCA commented on the Life Cycle Replacement of PILC Cable Systems project in their respective arguments and reply arguments.

Commission findings

393. In Decision 2013-435,⁴²⁸ and later in Decision 3100-D01-2015,⁴²⁹ the Commission approved the need for the Life Cycle Replacement of PILC Cable Systems project for purposes of capital tracker treatment for 2013 and 2015, respectively. Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1. However, this project did not meet the first tier capital tracker materiality threshold in 2013.

394. In its 2014-2015 capital tracker application, EPCOR did not request capital tracker treatment for this project in 2014, because the project did not meet the first tier materiality threshold in 2014 on a forecast basis. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application. EPCOR did however, apply for and received capital tracker treatment for this project in 2015.

395. The Commission observes that the K factor revenue requirement calculation for the Life Cycle Replacement of PILC Cable Systems project proposed for 2016 and 2017 incorporates the 2013 and 2014 actual capital additions for this project, that were incurred under the I-X mechanism prior to requesting capital tracker treatment, and forecast capital additions for 2015. As explained in Section 3 of this decision, in the absence of any evidence that the 2013 and 2014 capital additions for this project incurred under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

396. In the present application, EPCOR also requested capital tracker treatment for this project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Life Cycle Replacement of PILC Cable Systems project is not required to continue in 2016 or 2017.

397. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are \$2.23 million in 2016 and \$2.28 million in 2017. The Commission has reviewed the information supporting EPCOR's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable based on the length of PILC cable planned to be replaced each year, multiplied by historical unit

⁴²⁸ Decision 2013-435, paragraphs 867-868.

⁴²⁹ Decision 3100-D01-2015, paragraph 563.

cost for replacing PILC cable with TR-XLPE,⁴³⁰ subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

398. However, the Commission remains concerned about the robustness of EPCOR's PILC cable failure rate model on which the number of km of cable planned for replacement, as part of this project, is based. Ms. Hull⁴³¹ and Mr. Baraniecki⁴³² indicated that, following the exchanges with the Commission at the hearing, EPCOR is considering issuing an RFP for the PILC cable failure rate modeling, rather than doing it in-house, to address some of the concerns expressed by the Commission, including a sensitivity analysis. While the Commission is not directing that third-party PILC cable failure rate modeling be conducted, such an analysis may be of assistance in future true-up applications.

399. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Life Cycle Replacement of PILC Cable Systems project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.3 New forecast capital trackers

400. This section deals with EPCOR's projects or programs that have not been previously approved for capital tracker treatment. For such projects, the Commission determined that, as part of project assessment, the applicant must demonstrate that a project proposed for capital tracker treatment is required to provide utility service at adequate levels and that the scope, level, and timing of the project are reasonable and that the costs of the project are reasonable for forecast projects and prudent for completed projects.⁴³³

6.3.1 Work Centre Redevelopment

401. This is a defined scope project that is expected to occur over the period 2015 to 2017. EPCOR is undertaking the expansion and redevelopment of its North Service Centre (NSC) location, as well as redeveloping its South Service Centre (SSC) and training facilities.⁴³⁴

402. EPCOR explained that the buildings and facilities being redeveloped through this project are jointly used by EPCOR's transmission and distribution functions; however, as is the case with all of EPCOR Distribution and Transmission's land and buildings, the assets in this project are held by the distribution function. As a result, EPCOR's transmission function pays an asset usage fee to the distribution function for its use of the facilities.⁴³⁵ The asset usage fees are discussed in Section 6.1.5 of this decision. EPCOR's distribution function is applying for capital tracker treatment for the Work Centre Redevelopment project on a forecast basis for 2016 and 2017.

⁴³⁰ Exhibit 20407-X0087, Appendix A-17, paragraph 64.

⁴³¹ Transcript, Volume 2, page 264 lines 17-19 (Ms. Hull).

⁴³² Transcript, Volume 3, page 369 lines 17-22 (Mr. Baraniecki).

⁴³³ Decision 2013-435, paragraph 278.

⁴³⁴ Exhibit 20407-X0075, Appendix A-22, paragraph 1.

⁴³⁵ Exhibit 20407-X0075, Appendix A-22, paragraph 3.

403. EPCOR had previously sought approval for this project as a “zero K factor” in its 2013 capital tracker application;⁴³⁶ however, the Commission denied the concept of zero K factors in the decision for that proceeding.⁴³⁷ Moreover, the scope of the project brought forward by EPCOR in that proceeding was significantly different than the scope of the project put forth in the current proceeding.

404. The scope of the Work Centre Redevelopment project consists of three separate components: expansion, redevelopment, and consolidation at the NSC, redevelopment and consolidation at the SSC, and the relocation of EPCOR’s training facilities from their current location to a new site. The total forecast capital expenditures associated with the project are \$85.09 million, with capital additions of \$38.45 million and \$20.27 million in 2016 and 2017, respectively. The remainder of capital additions, \$26.38 million, were planned for 2015; however, at this time, EPCOR is not seeking capital tracker treatment for the 2015 costs of this project.

405. EPCOR provided the following breakdown of Work Centre Redevelopment project capital expenditures by component:

Table 13. Forecast capital expenditures for the Work Centre Redevelopment project⁴³⁸

Project component	Forecast capital expenditure (\$ million)	Description
NSC building 3 purchase	8.31	Includes the real estate consulting fees of approximately \$0.15 million.
NSC building 3 redevelopment	16.79	- Warehouse, office, and shops hard costs. - Furniture, fixtures and equipment.
Meter operations	0.15	HVT lab.
NSC Vehicle Garage	8.12	Includes garage demolition, renovation, expansion and related garage equipment.
Parking facility and yard optimization	5.82	Includes \$4.5 million for 150 additional parking stalls.⁴³⁹
NSC building 2	6.54	- Code and system upgrades. - Building improvements. - Furniture, fixtures and equipment.
NSC building 1	19.52	- Includes control room costs of \$1.77 million. - Code and system upgrades. - Building improvements. - Furniture, fixtures and equipment.
Exterior work	1.78	- Façade work. - Landscaping.
SSC	4.10	- Code and system upgrades. - Building improvements. - Furniture, fixtures and equipment.
Training facilities	1.80	Construction of small, pre-engineered building at Winterburn location.

⁴³⁶ Proceeding 2131, Distribution Performance-Based Regulation 2013 Capital Tracker Applications, Application 1608827-1.

⁴³⁷ Decision 2013-435, paragraph 981.

⁴³⁸ Exhibit 20407-X0074, Appendix A-22, Attachment 3, forecast capital.

⁴³⁹ Transcript, Volume 2, page 316, line 19 to page 317, line 8.

Project component	Forecast capital expenditure (\$ million)	Description
Soft costs	8.03	• Engineering and design soft costs.
Inflation	1.77	
EPCOR allocated overhead (1%)	0.82	
AFUDC	1.51	
Total	85.09	

NSC and SSC

406. Until recently, the NSC location consisted of two buildings (building 1 and building 2), as well as a vehicle garage and a storage yard. Building 1 was built in 1957, and expanded in the 1980s to include a floor of offices. Building 2 was purchased by EPCOR in 2005 and renovations were subsequently completed, which allowed EPCOR to consolidate multiple functions from other sites into the NSC location. The vehicle garage provides indoor parking for EPCOR's fleet and the storage yard includes, but is not limited to, a carpentry shop, pole storage, a machine shop, a tool repair shop, and storage sheds.⁴⁴⁰

407. EPCOR explained that the primary driver of the Work Centre Redevelopment project and the driver of the NSC portion of the project is that the NSC facilities are nearing the end of their useful lives and require replacement. Furthermore, EPCOR stated that the NSC facilities do not have sufficient garage, parking, office, and shop space and, therefore, are unable to meet EPCOR's facility needs without expansion and renovation. Specifically, EPCOR indicated that there are inadequate emergency operations centre facilities, as well as a shortage of space for its control centre, transformer shop and warehouse space to meet the current and future needs of EPCOR's operations.⁴⁴¹

408. As a result of the space shortage, EPCOR began pursuing the purchase of the building and land adjacent to the NSC location. In September of 2014, a deal was reached for EPCOR to purchase the property and take full possession by June, 2015.⁴⁴² The new building (building 3) has approximately 6,550 square meters of floor space and sits on approximately 3.39 acres of land. EPCOR stated that the purchase of these facilities provides sufficient space to continue to "operate and maintain its system in a safe and reliable manner."⁴⁴³

409. EPCOR explained, during the hearing, that separate third-party market appraisals of building 3 and the land were commissioned by EPCOR and the seller.⁴⁴⁴ EPCOR's initial market appraisal had an estimated value of \$7.22 million and the seller's had an estimated value of \$8.57 million. Following that, EPCOR had its appraiser complete a supplementary analysis that estimated a market value of \$7.58 million. Given that there was a discrepancy between the supplementary analysis and the seller's appraisal, EPCOR and the seller commissioned a joint appraisal that estimated the value at \$11.50 million. After negotiations, EPCOR and the seller decided on a price of \$8.17 million, which represented a mid-point of its supplementary analysis

⁴⁴⁰ Exhibit 20407-X0075, Appendix A-22, paragraph 8.

⁴⁴¹ Exhibit 20407-X0075, Appendix A-22, paragraph 2.

⁴⁴² Exhibit 20407-X0075, Appendix A-22, page 6, paragraph 20.

⁴⁴³ Exhibit 20407-X0075, Appendix A-22, page 6, paragraph 20.

⁴⁴⁴ Transcript, Volume 2, page 313, line 18 to page 314, line 12.

and the seller's appraisal.⁴⁴⁵ EPCOR provided copies of its initial appraisal, supplementary analysis, and the joint appraisal in response to an undertaking to Commission counsel.⁴⁴⁶

410. Prior to the purchase of building 3, EPCOR completed a building condition assessment and determined that some code, electrical and mechanical system upgrades would be required. EPCOR explained that these upgrades were considered in its negotiations when purchasing building 3.⁴⁴⁷

411. Also included in the scope of the NSC portion of this project is the redevelopment and renovation of buildings 1, 2 and 3. Among the redevelopment work being completed at the NSC buildings is the renovation of the layout to align with EPCOR's work centre plan and system upgrades to bring the facilities up to current building code requirements, improved common areas, washrooms, locker rooms, and handicap accessibility. The redevelopment of each building will also include the installation of the required furniture, building fixtures, and other equipment.⁴⁴⁸ Specific to building 1, EPCOR is expanding and renovating its transformer shop and control room, while adding a high-voltage test (HVT) lab and a new emergency operations centre.⁴⁴⁹

412. EPCOR also plans to complete work on the exterior of the NSC facilities including replacing doors and windows that are in poor condition, and repairing the buildings' facades and roofs.⁴⁵⁰

413. EPCOR is planning on expanding the current available space in its NSC garage by 84 per cent. EPCOR explained that 20 vehicles, which required indoor parking due to specialized electronic and hydraulic equipment, are currently parked outside.⁴⁵¹

414. The parking and yard storage areas at the NSC location are also being redeveloped as part of the Work Centre Redevelopment project. EPCOR plans to expand and optimize its storage yard, as well as to complete repairs to the current pavement and improve site drainage.⁴⁵² EPCOR explained that as a result of the application for development permits for the Work Centre Redevelopment project, an expansion to its parking area was required in order to comply with City of Edmonton Bylaw 12800, section 54.2, Schedule 1.⁴⁵³ EPCOR stated:

In order to comply with Bylaw 12800 and meet EDTI's future operational requirements for staff and visitor parking, EDTI estimates that it will require an additional 150 parking spaces (including 35 additional parking spaces required on completion of the Work Centre Project, and an additional 115 parking spaces to meet forecast growth in the number of employees located at the NSC site in 10 years).⁴⁵⁴

⁴⁴⁵ Exhibit 20407-X0197, undertaking response, Mr. McNeil to Mr. McNulty at Transcript, Volume 2, page 314.

⁴⁴⁶ Exhibit 20407-X0197, undertaking response, Mr. McNeil to Mr. McNulty at Transcript, Volume 2, page 314.

⁴⁴⁷ Exhibit 20407-X0075, Appendix A-22, paragraph 36.

⁴⁴⁸ Exhibit 20407-X0075, Appendix A-22, pages 15, 17 and 18.

⁴⁴⁹ Exhibit 20407-X0075, Appendix A-22, pages 17-18.

⁴⁵⁰ Exhibit 20407-X0075, Appendix A-22, pages 18 and 23.

⁴⁵¹ Exhibit 20407-X0075, Appendix A-22, pages 15-16.

⁴⁵² Exhibit 20407-X0075, Appendix A-22, page 18.

⁴⁵³ Transcript, Volume 2, page 316, lines 3-12.

⁴⁵⁴ Exhibit 20407-X0075, Appendix A-22, page 16.

415. As set out in Table 13, EPCOR's forecast costs associated with the parking facility and yard optimization component of the project are \$5.82 million. Mr. McNeil, on behalf of EPCOR, provided a further breakdown of those costs during the hearing:

A. ... the basis for our cost forecast there was an estimated 150 parking stalls at a forecast cost of approximately \$30,000 per stall. That 150 -- 150 stalls times that 30,000 equals \$4.5 million. So the remaining -- so the 5.8 less the 4.5 million would represent yard-related work at the NSC site.

Q. Which is driven by this redevelopment program; right?

A. That's correct.

Q. And the \$30,000 unit cost per stall, how was that arrived at?

A. We received that from -- EDTI has hired a project management firm as part of this project to assist us. And that was the unit rate that was used for the purposes of this forecast.⁴⁵⁵

416. The other component of the Work Centre Redevelopment project as it relates to the NSC, is the consolidation of EPCOR employees. Currently, EPCOR has distribution, transmission, and shared services employees at the NSC, SSC, St. Albert Trail Service Centre (SATSC), South Training Centre (STC), and the EPCOR Tower in downtown Edmonton. The SATSC and EPCOR Tower locations are not owned by EPCOR Distribution and Transmission Inc., rather EPCOR currently leases space at those locations from ETECH and EUI, respectively.

417. Included in EPCOR's consolidation plans are the relocation of classroom training from the STC to the NSC, which involves moving 10 technical training employees. Field-based training is being relocated from the STC to a new location, as discussed below.⁴⁵⁶ Also relocating to the NSC, are 33 employees currently located at EPCOR Tower in the regulatory, supply chain, human resources, and operational communications departments. EPCOR further plans on relocating meter operations employees currently at the SATSC and NSC sites to the SSC. Finally, EPCOR stated that some employees may shift between the NSC and SSC based on the optimization of its operations. EPCOR confirmed that the moving costs associated with the consolidation activities in this project are not included in the capital additions associated with this project because they are expensed as O&M costs.⁴⁵⁷

418. In order to accommodate the consolidation of employees, EPCOR is planning on redeveloping the SSC. Specifically, the scope of the project relating to the SSC includes the reconfiguration of workspaces, replacement of furniture and fixtures, upgrades to the fire detection system, and parking lot repairs. EPCOR's meter operations are moving from the SATSC to the SSC. Therefore, EPCOR is converting its maintenance shop to include meter operations.⁴⁵⁸

419. Given that EPCOR's service centres are used by both its distribution and transmission functions and the transmission function pays an AUF to the distribution function for the capital cost of the building, EPCOR was asked to explain which of the functions was primarily driving the need for the Work Centre Redevelopment project. EPCOR noted that both functions required

⁴⁵⁵ Transcript, Volume 2, page 316, line 19 to page 317, line 8.

⁴⁵⁶ Exhibit 20407-X0075, Appendix A-22, page 19.

⁴⁵⁷ Transcript, Volume 2, page 310, lines 5-9.

⁴⁵⁸ Exhibit 20407-X0075, Appendix A-22, paragraph 49.

additional space for joint-use facilities, such as warehousing and the storage yard; however, the transmission function comprises approximately 23 per cent of the EPCOR workforce.⁴⁵⁹

420. EPCOR's view is that having separate transmission and distribution facilities does not make sense given the shared services and integration between the two functions.⁴⁶⁰ Furthermore, EPCOR stated that there are cost savings as a result of having a joint distribution and transmission facility.⁴⁶¹

Facility space analysis

421. In support of the Work Centre Redevelopment project, EPCOR commissioned a facility space requirement study in 2011 and then an updated study in 2014, when the acquisition of building 3 became a possibility.⁴⁶² The space study, which was conducted by Stantec Consulting Ltd., analyzed the current and future space requirements at EPCOR's NSC and SSC locations. The study also broke down the space requirements across office, field, warehouse, vehicle garage, and shop space at both the NSC and SSC.

422. The study assumed an annual employee growth rate of 2.0 per cent, which was based on a three-year historical average from 2010 to 2013 and represents a mid-point of other historical average growth rates,⁴⁶³ to forecast future space requirements in 10, 20, and 30 years. Sensitivity analysis was performed on the 2.0 per cent employee growth rate to illustrate the effect of a 0.5 per cent increase or decrease on the growth rate over the 10, 20, and 30 year periods. The summary analysis of the space study is set out in Table 14 below:

⁴⁵⁹ Transcript, Volume 2, page 290, line 23 to page 291, line 25.

⁴⁶⁰ Transcript, Volume 2, page 289, line 16 to page 290, line 18.

⁴⁶¹ Transcript, Volume 2, page 292, lines 18-21.

⁴⁶² Exhibit 20407-X0075, Appendix A-22, paragraphs 51 and 52.

⁴⁶³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-065.

Table 14. EPCOR facility space analysis summary⁴⁶⁴

EDTI facility space (building gross square metres)	Current	Following Work Centre project	10-year forecast	20-year forecast	30-year forecast
Total NSC	14,865	25,888	25,888	25,888	25,888
Total SSC	9,418	9,418	9,418	9,418	9,418
Total space	24,283	35,306	35,306	35,306	35,306
Total space required	29,325 ⁴⁶⁵	29,325	33,057	37,890	43,525
surplus/(deficit)	-5,042 ⁴⁶⁶	5,981	2,249	-2,584	-8,219
Sensitivity analysis					
Total space required at 1.5% growth		29,325	32,254	35,979	40,115
surplus/(deficit)		5,981	3,052	-673	-4,809
Total space required at 2.5% growth		29,325	33,896	39,987	47,456
surplus/(deficit)		5,981	1,410	-4,681	-12,150

423. The “current total space required” shown in Table 14, represents the facility space EPCOR requires at its NSC and SSC locations following the consolidation activities described above. Following the completion of the Work Centre Redevelopment project, EPCOR expects to add approximately 11,000 building gross square metres (BGS⁴⁶⁷) to address the current space deficit.

424. During the hearing, Mr. Baraniecki expanded on the space issues that EPCOR is currently facing:

It is very challenging to have maybe an employee move from one area of the company to another. And it's not even expansion and trying to find a place to put them. Expansion has to do a little bit with it, but it has a lot to do with the people we already have.

There's examples throughout the business cases. I'm not sure it's actually in this one, but it might have been in a previous business case where we have lockers in hallways because there's no space to put the crews.

You know, there's inadequate washroom space for our female trades crew and inadequate change facilities. Those kind of things are significant challenges for us.

You know, like, literally we have a new employee come in or even an employee transfer from one area to another, say from the south service centre to the north service centre. A bunch of us directors have to sit down and negotiate where we're going to put that person and can we move this person here and that person there? Should we take this set of area and try to move it down to 2 by 2 cubicles as opposed to something adequate? That may

⁴⁶⁴ Exhibit 20407-X0074, Appendix A-22, Attachment 3, space analysis, Table 2.2.2.1-1.

⁴⁶⁵ The value in this cell was calculated by adding the “currently required, sub-total SSC” value of 8,927 from Table 2.2.2.4-1 and the “currently required, total space following consolidation” value of 20,398 from Table 2.2.2.3-1. All tables are proved in Exhibit 20407-X0074, Appendix A-22, Attachment 3, space analysis.

⁴⁶⁶ The value in this cell was calculated by adding the “currently required, sub-total SSC, surplus/deficit” value of 491 from Table 2.2.2.4-1 and the “currently required, total space following consolidation, surplus/deficit” value of -5,533 from Table 2.2.2.3-1. All tables are proved in Exhibit 20407-X0074, Appendix A-22, Attachment 3, space analysis.

⁴⁶⁷ Value calculated as “total space following work centre project” of 35,306 minus “total space current” of 24,283.

be an extreme example. But, you know, reduce cubicle sizes, those kind of things, just to jam pack employees. We're jammed in there. We need the space just to even survive what we have.

Short-term you can do things. Long-term, it's just not a great working environment that we have.⁴⁶⁸

425. Furthermore, regarding the 20 year forecast space deficit of 2,584 BGSM, shown in Table 14, EPCOR stated that:

EDTI is confident that if its growth does prove to be consistent with the 2% assumption, EDTI will be able to find ways to make the space work to accommodate its needs over the last few years of the 20 year period, such that the project will accommodate EDTI's operations for a minimum 20 year period.⁴⁶⁹

Cost minimization

426. In order to proceed with the Work Centre Redevelopment project, EPCOR engaged a professional project management company to help with the delivery of the project. EPCOR also contracted an architecture firm for the design of the buildings and their mechanical, structural and electrical systems. In both instances, EPCOR received multiple submissions⁴⁷⁰ and selected the lowest cost company that could meet the scope and requirements of the RFP.⁴⁷¹

427. EPCOR explained that it plans on issuing three separate RFPs for the vendor selection process for the control centre and warehouse construction at the NSC, the interior renovations to the NSC buildings, and garage and multi-purpose areas at the NSC. The RFPs and vendor selection process for the NSC related work is expected to be complete by February 2016. For the SSC, EPCOR will issue a separate RFP and select a vendor by April 2016.⁴⁷²

428. In addition to the project management procedures discussed in Section 6.1.4 of this decision, EPCOR, in the business case for the Work Centre Redevelopment project, outlined the steps it would take to minimize the costs of the project including:

- Where possible, work will be coordinated with other projects or maintenance activities to minimize costs.
- EDTI uses industry standard materials allowing the re-use of certain components in order to minimize project costs.
- Where possible, EDTI will utilize some of the office space and furniture standards that EPCOR developed for use in the EPCOR Tower project, resulting in minimum costs required to design the office spaces for the new service centre.
- Cost savings are anticipated through the implementation of efficient space design considerations and the use of spaces for multiple purposes (e.g., using crew gathering areas as training spaces or meeting rooms during the day time, the development of a multi-purpose area).⁴⁷³

⁴⁶⁸ Transcript, Volume 2, page 282, line 22 to page 283, line 24 (Mr. Baraniecki).

⁴⁶⁹ Exhibit 20407-X0075, Appendix A-22, paragraph 56.

⁴⁷⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-062.

⁴⁷¹ Exhibit 20407-X0075, Appendix A-22, paragraph 101.

⁴⁷² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-060.

⁴⁷³ Exhibit 20407-X0075, Appendix A-22, page 63.

429. Regarding the consolidation of employees from the SATSC to the NSC and SSC, EPCOR confirmed that it provided advanced notice that it would not continue to lease the space and does not expect to incur costs associated with termination of the service level agreement for the lease.⁴⁷⁴

430. Regarding the consolidation of employees from EPCOR Tower to its service centres, EPCOR explained that:

At EPCOR Tower, EDTI is allocated direct rent costs on a square footage basis associated with EPCOR Utilities Inc.'s ("EUI's") lease of the building. As EDTI vacates the premise, EDTI's direct rent portion will decrease, and there are no direct costs associated with a lease termination as the space vacated by EDTI will return to EUI. However, corporate allocations may increase after EDTI vacates the EPCOR Tower space given that the costs associated with the square footage that EDTI occupied will move back into the EUI Corporate Services cost pool.⁴⁷⁵

431. In an IR response to the UCA, EPCOR provided an net present value (NPV) analysis of the savings in direct rent resulting from leaving EPCOR Tower and the SATSC.⁴⁷⁶ Furthermore, by way of an undertaking response, EPCOR provided the net cost impact from 2015 to 2018 of the Work Centre Redevelopment project that includes direct rent savings, corporate cost increases, and capital costs net of AUFs, as set out in Table 15:

Table 15. Work Centre Redevelopment net savings impact⁴⁷⁷

	2015	2016	2017	2018
	(\$ million)			
EPCOR Tower direct rent savings	-	0.21	0.22	0.44
Increase in corporate allocations	-	(0.07)	(0.07)	(0.15)
SATSC direct rent savings	-	-	0.58	1.18
Capital costs for Work Centre Redevelopment Project (net of asset usage fees received from Transmission function)	(0.97)	(3.09)	(5.10)	(5.86)
Forecast increase in building operating costs as a result of expansion at NSC (building 3)	(0.23)	(0.33)	(0.33)	(0.33)
Total net savings	(1.20)	(3.28)	(4.71)	(4.72)

Analysis of alternatives to the project

432. In support of the Work Centre Redevelopment project, EPCOR provided an analysis of alternatives that would also address the facility space deficit. The alternative analysis compared the Work Centre Redevelopment project to four alternatives on the basis of facility space provided and capital costs. The first alternative EPCOR considered was to expand its NSC location (buildings 1 and 2) and construct parking underneath the buildings to provide additional yard space and storage. The second alternative was for EPCOR to purchase a new site and build

⁴⁷⁴ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-059(c).

⁴⁷⁵ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-059(c).

⁴⁷⁶ Exhibit 20407-X0155, EDTI-UCA-2015-JUN26-013(c).

⁴⁷⁷ Exhibit 20407-X0196, response to undertaking given by Mr. McNeil to Mr. McNulty at Transcript, Volume 2, page 307.

a new service centre to which it would relocate its NSC operations. Under the third alternative, EPCOR would renovate the existing NSC to current standards and build a new service centre at a new site to accommodate growth and the space deficit. Finally, EPCOR considered renovating the current NSC and leasing additional space long-term to provide the necessary space.⁴⁷⁸

433. The following table sets out the facility space that EPCOR estimated to have following the completion of the alternative projects:

Table 16. Work Centre Redevelopment project facility space alternative analysis (BGSM)⁴⁷⁹

Alternatives	Work Centre project	Alternative 1 expand current NSC	Alternative 2 build new	Alternative 3 renovate NSC & build new	Alternative 4 renovate NSC & lease new
Office and general - new space	0	5,170	20,309	10,109	0
Office and general - renovate	15,370	10,200	0	10,200	10,200
Warehouse - new space	0	781	1,800	628	0
Warehouse - renovate	1,953	1,172	0	1,172	1,172
Garage - new space	3,900	3,900	9,330	4,665	0
Garage - renovate	4,665	4,665	0	4,665	4,665
SSC space	9,418	9,418	9,418	9,418	9,418
Leased space	0	0	0	0	15,402
Total space	35,306	35,306	40,857	40,857	40,857

434. In addition to the facility space comparison, EPCOR provided forecast capital expenditures for each of the alternatives considered, as set out in the table below:

Table 17. Work Centre Redevelopment project forecast capital expenditures alternative analysis⁴⁸⁰

Project component	Work Centre project	Alternative 1 expand current NSC	Alternative 2 build new	Alternative 3 renovate NSC & build new	Alternative 4 renovate NSC & lease new
	(\$ million)				
Land and improvement costs	8.3	58.0	29.0	14.5	0.0
Construction costs	57.1	51.0	68.6	59.5	26.6
PV of capital lease (including inflation)	0.0	0.0	0.0	0.0	50.6
Engineering & design costs	8.2	7.7	10.3	8.9	4.0
Contingency	0.0	0.0	0.0	0.0	0.0
LEED premium	0.0	0.0	3.3	1.6	0.0
Equipment costs	7.4	7.7	17.8	9.6	4.6
Inflation	1.8	5.7	5.9	4.3	1.6
EPCOR overhead	0.8	1.3	1.3	1.0	0.4
AFUDC	1.5	4.7	4.9	3.6	1.4
Total	85.1	136.0	141.2	103.0	89.3

⁴⁷⁸ Exhibit 20407-X0075, Appendix A-22, paragraph 82.

⁴⁷⁹ Exhibit 20407-X0075, Appendix A-22, paragraph 83, Table 2.2.4.2-1.

⁴⁸⁰ Exhibit 20407-X0074, Appendix A-22, Attachment 3, capital (Alt 2-5) and summary, Table 2.2.4.2-2.

435. In evaluating the forecast capital expenditures of the alternative projects, EPCOR noted that the Work Centre Redevelopment project has the lowest upfront capital costs, and alternatives 3 and 4 do not achieve the consolidation of EPCOR's service centres.⁴⁸¹

436. EPCOR examined the costs of the alternatives using a present value (PV) revenue requirement analysis, as set out in the table below. In the PV analysis of the revenue requirement costs, EPCOR assumed the depreciable life of the assets was 45 years and the life of the lease was 20 years.⁴⁸²

Table 18. Work Centre Redevelopment project revenue requirement PV alternative analysis⁴⁸³

Alternative	Work Centre project	Alternative 1 expand current NSC	Alternative 2 build new	Alternative 3 renovate NSC & build new	Alternative 4 renovate NSC & lease new
	(\$ million)				
Present value of revenue requirement impact (without return)	75.8	101.4	87.2	109.3	123.9

437. EPCOR also compared the alternatives using the NPV analysis of life cycle costs, as set out in Table 19:

Table 19. Work Centre Redevelopment project life cycle NPV alternative analysis⁴⁸⁴

Row	Life cycle costs	Work Centre project	Alternative 1 expand current NSC	Alternative 2 build new	Alternative 3 renovate NSC & build new	Alternative 4 renovate NSC & lease new
		(\$ million)				
1	Cash used for facility operations	48.3	63.4	57.0	80.8	79.4
2	Land, buildings & equipment	75.4	112.6	116.8	85.2	31.9
3	PV of Lease	0.0	0.0	0.0	0.0	50.6
4	Construction financing (AFUDC)	1.4	4.1	4.2	3.1	1.2
5	Annual capital renewal	6.7	11.4	11.8	8.6	3.2
6	Cash used for capital investments (Sum of rows 2 to 5)	83.5	128.0	132.9	96.9	87.0
7	NPV of Life Cycle Costs (row 1 + 6)	131.8	191.4	189.9	177.7	166.4

⁴⁸¹ Exhibit 20407-X0075, Appendix A-22, paragraph 84.

⁴⁸² Exhibit 20407-X0075, Appendix A-22, paragraph 111.

⁴⁸³ Exhibit 20407-X0075, Appendix A-22, paragraph 111, Table 4.1.1-2.

⁴⁸⁴ Exhibit 20407-X0075, Appendix A-22, paragraph 111, Table 4.1.1-2.

438. Overall, EPCOR noted that it preferred the Work Centre Redevelopment project alternative because it had the lowest NPV of life cycle cost, the lowest PV of revenue requirement, and the lowest forecast capital costs.⁴⁸⁵ Furthermore, EPCOR explained that:

Given the land and building purchased by EDTI in September 2014 and the subsequent increase in space available at the NSC site, EDTI now has the available space with which to redevelop facility space at the NSC site. Further, the increase in available space at the NSC site has also enabled EDTI to review the location of EDTI's departments across all current work centres (NSC, SSC, STC, SATSC, and STC) and consolidate EDTI departments to a combination of the redeveloped NSC site or SSC site.⁴⁸⁶

439. The training facilities component of the Work Centre Redevelopment project, which is discussed below, was included in all four of the alternatives that EPCOR considered, at the same forecast cost.⁴⁸⁷

Training facilities

440. Currently, EPCOR conducts its training at the STC, which in its view, is no longer able to support those activities. EPCOR explained that it completed roof repairs on the STC in 2014; however, if it continues to occupy the building, additional repairs may be required.⁴⁸⁸ As a result, classroom training is being moved to the NSC. EPCOR also explained that the field-based training facilities at the STC do not provide sufficient space to complete technical training. By way of example, EPCOR stated that there is insufficient space to simulate true aerial span lengths and realistic live line pole replacements. There is also insufficient space to complete underground training for its apprentices and journeymen. As a result, EPCOR is moving its field-based training to the Winterburn site, which EPCOR also owns.⁴⁸⁹

441. Currently, the Winterburn site is used by EPCOR as its dewatering facility; however, EPCOR decided to repurpose the site following increased contractor costs of running the dewatering facility. EPCOR explained that it will use an affiliate for future dewatering services and the costs of decommissioning the dewatering facility are not included in the scope of this project.⁴⁹⁰ To accommodate its field-based training at the Winterburn site, EPCOR is moving the training equipment currently located at the STC and constructing a small pre-engineered building to house on-site theory training.⁴⁹¹

442. In order to complete the work at the Winterburn site for the field based training facility, EPCOR issued an RFP and selected a design build contractor in May of 2015.⁴⁹²

443. Following the relocation of EPCOR's training facilities to the Winterburn site by the second quarter of 2017, the STC will no longer be in use. EPCOR explained that it is evaluating

⁴⁸⁵ Exhibit 20407-X0075, Appendix A-22, paragraph 113.

⁴⁸⁶ Exhibit 20407-X0075, Appendix A-22, paragraph 113.

⁴⁸⁷ Exhibit 20407-X0075, Appendix A-22, page 55.

⁴⁸⁸ Exhibit 20407-X0075, Appendix A-22, paragraph 41.

⁴⁸⁹ Exhibit 20407-X0075, Appendix A-22, paragraph 44.

⁴⁹⁰ Transcript, Volume 2, page 320, line 23 to page 321, line 24.

⁴⁹¹ Exhibit 20407-X0075, Appendix A-22, page 19.

⁴⁹² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-060.

options for the STC location, including creating additional materials storage or selling the facility. EPCOR expects that it will complete its options review by the end of 2016.⁴⁹³

444. In EPCOR's formal alternative analysis, discussed above, the move of the field-based training facilities from the STC to the Winterburn site was included in all alternatives presented. However, in its business case, EPCOR provided a qualitative discussion of possible alternatives to meet its training facility requirements. Specifically, EPCOR considered redeveloping the current STC and partnering with another utility for a joint training facility. EPCOR explained that redeveloping the current STC was not a practical option given the training yard was too small for all the technical training requirements, including an underground training area.⁴⁹⁴

445. Regarding the potential to partner with another utility in a joint training facility, EPCOR stated that this option would not be viable for a number of reasons. First, EPCOR explained that other utility training facilities are typically located outside of the City of Edmonton, which increases travel expenses and time.⁴⁹⁵ Furthermore, the training equipment of other utilities is designed to the standards of that utility and EPCOR stated that it is critical that its field-based employees be trained on equipment that reflects its system's standards.⁴⁹⁶ EPCOR had further concerns regarding the scheduling and availability of a joint training facility, given that it plans on using its Winterburn site for training when the weather is poor and would, therefore, be unable to coordinate in advance with another utility.⁴⁹⁷

446. In support of its dedicated Winterburn training site, EPCOR stated:

Having a dedicated training centre allows EPCOR staff to learn and apply practical skills on equipment that has the same specifications and the same configurations as the equipment EPCOR has installed in the field. This creates a realistic simulation environment that is identical to what the worker will experience in the field. Equipment configurations like this are not available through post-secondary institutions like NAIT or at the training centres of other utilities. Training EPCOR employees on equipment with different specifications or different configurations would not ensure that workers learn the skills to perform field work on EDTIs system competently and safely.⁴⁹⁸

447. In an IR response to the Commission, EPCOR stated that, in early 2015, it had conversations with ATCO Electric Ltd. regarding the possibility of a joint training centre. Following these conversations, EPCOR concluded, as discussed in its business case, that a joint training centre was not a viable option and added:

EDTI also notes that under Section 15 Safety training of Alberta Occupational Health and Safety ("OH&S") Regulation, employers are required to train workers in the safe operation of the equipment the worker is required to operate. Training employees on more generic equipment may be useful for high level theoretical training, but would not be adequate to ensure employees are not put at risk in the absence of further utility-specific training. Proper training on the equipment, standards, and procedures specific to

⁴⁹³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-063(a) and (b).

⁴⁹⁴ Exhibit 20407-X0075, Appendix A-22, paragraph 45.

⁴⁹⁵ Exhibit 20407-X0075, Appendix A-22, page 34.

⁴⁹⁶ Exhibit 20407-X0075, Appendix A-22, page 34.

⁴⁹⁷ Exhibit 20407-X0075, Appendix A-22, pages 34-35.

⁴⁹⁸ Exhibit 20407-X0075, Appendix A-22, page 35.

EDTI is essential given that any mistakes can create significant safety and reliability issues.⁴⁹⁹

448. During the hearing, the option of a joint training facility between ATCO Electric and EPCOR was discussed further by EPCOR and Commission counsel:

Q. And if you're going to have separate equipment, because you need EPCOR-specialized equipment, ATCO needs specialized ATCO Electric equipment, why would you have difficulty both of you being there at the same time?

A. MR. BARANIECKI: Well, you would -- there's also classroom space and other common space within a training facility that you don't design to do twice as much stuff. You know, if you did that kind of -- you know, designed a facility like that, you would completely erode any even perceived benefits of having a joint utility training space.

When we really look at this, the fact that we need to put in our own equipment and train on our own equipment, do everything ourselves, having it co-located in building with another utility that's, you know, further away than what we would have to travel, it's no cost savings and just adding a bunch of extra costs on to it. And then combining that with scheduling issues, extra travel, and the fact that we actually own the land already and we don't have to pay for it, this solution to us seems the most reasonable and the best use of what we have and the cheapest way of providing our training and good training for our employees so we keep them competent, so we can make sure that they can provide adequate service, and we can do the proper safety training and keep those employees safe.⁵⁰⁰

449. EPCOR also discussed in an IR response, why partnering with a post-secondary institution such as the Northern Alberta Institute of Technology (NAIT) was not also a viable option; however, it noted that it had not engaged in direct conversations with NAIT, at that time. Currently, EPCOR and NAIT work together on apprenticeship theory training, as it is applicable to the employees of multiple utilities. On the other hand, technical training, which EPCOR plans to provide at its Winterburn site, is unique to EPCOR's equipment, standards, procedures, and operations. Furthermore, EPCOR explained that in order to provide the technical training, NAIT instructors would require experience on the equipment and standards of EDTI's distribution and transmission systems, which would require training of the instructors and the expenditure of resources.⁵⁰¹ In the oral hearing, EPCOR explained that subsequent to filing its IR responses, it had a conversation with NAIT indicating the following in an exchange with Commission counsel:

A. If NAIT has buildings and facilities available already, or even if they have to be modified, wouldn't it be cheaper than building new buildings and redeveloping existing sites?

A. MR. BARANIECKI: So I guess the point is that they don't have the buildings and the space available. And so we would have to provide funding for them to redevelop or build the buildings, require more land around their area to do that.

⁴⁹⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-064(a).

⁵⁰⁰ Transcript, Volume 2, page 326, line 15 to page 327, line 16 (Mr. Baraniecki).

⁵⁰¹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-064(b).

Q. And you confirmed that in your discussions with NAIT?

A. MR. MCNEIL: Yes, we did. We are – our training facility will be approximately 3 acres or so in terms of the space. So it's quite a large piece of property.⁵⁰²

450. Overall, EPCOR expects that all components of the Work Centre Redevelopment project to be complete, and that all of the land and buildings purchased at the NSC in 2014, “will be used in their entirety to provide utility service” by the end of 2017.⁵⁰³

451. During the hearing, EPCOR provided an update of the project schedule and forecast budget:

And at this point we don't see any material changes in what we've forecast for the total costs of this project. There may be a couple of things that move from '15 into '16, but the two main factors is overall the budget -- we don't see any material changes in the overall budget, and the -- we expect to have this project completed still within mid 2017.⁵⁰⁴

452. As discussed in Section 5.2.2, the CCA raised an issue with respect to the Work Centre Redevelopment project and its grouping for capital tracker purposes. In addition, the CCA took issue with the repair and maintenance costs being included in the Work Centre Redevelopment project for the purposes of the K factor calculation because EPCOR has not shown that there are insufficient funds in its PBR going-in rates to cover the cost of the repairs.⁵⁰⁵ Further, the CCA argued that maintenance activities such as roof repairs, should be an O&M expense and funded by way of the I-X mechanism.⁵⁰⁶ In argument, the CCA suggested that repair-related expenses should be removed from the capital trackers, stating:

... prudence and an abundance of caution would dictate that the repairs should be made regardless of whether the project was undertaken. Therefore the distinction that EDTI makes that the repair costs should be included in the project is incorrect and the Commission should direct that such costs be excluded from the calculation of the K factor.⁵⁰⁷

453. EPCOR, in its reply argument, responded that the repair and maintenance costs associated with the Work Centre Redevelopment project are capital in nature, according to its capitalization policy, and consistent with historical treatments of capital projects.⁵⁰⁸ EPCOR further noted that:

As such, the [capital tracker] models ensure that only EDTI's capital maintenance and repair expenses that are not funded under I-X and which otherwise meet the Commission's Tracker criteria are included in the K factor, in turn ensuring that there is no double recovery as contemplated in the Commission's Capital Tracker mechanism.⁵⁰⁹

⁵⁰² Transcript, Volume 2, page 330, line 13 to page 331, line 11 (Mr. Baraniecki and Mr. McNeil).

⁵⁰³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-056.

⁵⁰⁴ Transcript, Volume 2, page 298, lines 12-18 (Mr. Baraniecki).

⁵⁰⁵ Exhibit 20407-X0234, CCA argument, paragraph 149.

⁵⁰⁶ Exhibit 20407-X0234, CCA argument, paragraphs 150 and 167.

⁵⁰⁷ Exhibit 20407-X0234, CCA argument, paragraph 155.

⁵⁰⁸ Exhibit 20407-X0237, EPCOR reply argument, paragraph 64.

⁵⁰⁹ Exhibit 20407-X0237, EPCOR reply argument, paragraph 65.

454. The UCA made no comments in its argument or reply argument regarding the Work Centre Redevelopment project.

Commission findings

455. The Commission has reviewed the business case and engineering study provided by EPCOR and the evidence on the record of this proceeding with respect to the Work Centre Redevelopment project and finds that the information provided by EPCOR supports a finding that the project is required during 2016 and 2017 to maintain service reliability and safety at adequate levels for the reasons below.

456. Specifically, EPCOR provided evidence regarding the current condition of its existing NSC buildings (building 1 and building 2) including required building and fire code requirements⁵¹⁰ and exterior issues such as the building façades and roof structures.⁵¹¹

457. The Commission accepts generally the evidence provided in EPCOR's facility space study indicating that the company has a current and future shortage of facility space for training, storage and operating purposes. The purchase of the additional facility space and land at the existing NSC location allows EPCOR to meet its space requirements as demonstrated by the space study. The Commission relies on EPCOR's statements that the Work Centre Redevelopment project would provide sufficient space for its operations for approximately 20 years.⁵¹²

458. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable. Specifically, the scope and level of the Work Centre redevelopment project is supported by EPCOR's business case that explains this project is being undertaken to address a shortage in facility space and issues within the existing service centres. With respect to the scope and level of the portion of the project relating to the relocation of training facilities from the STC to the Winterburn site, the Commission accepts the evidence of EPCOR that the field-based training facilities at the STC do not provide sufficient space to complete technical training, including simulation of aerial span lengths and live line poles replacements. There is also insufficient space to complete underground training. The Commission's finding with respect to the timing of this project is supported by the facility space study, which shows EPCOR is currently facing a space deficit.

459. EPCOR's forecast capital additions associated with this project are \$38.45 million in 2016 and \$20.27 million in 2017.⁵¹³ The Commission has reviewed the information supporting EPCOR's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable based on a number of factors, which are discussed below, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

⁵¹⁰ Exhibit 20407-X0075, Appendix A-22, paragraph 29.

⁵¹¹ Exhibit 20407-X0075, Appendix A-22, pages 18 and 23.

⁵¹² Exhibit 20407-X0075, Appendix A-22, paragraph 56.

⁵¹³ Exhibit 20407-X0130.02, revised application, paragraph 594.

460. EPCOR provided a detailed breakdown of the costs related to each component of the Work Centre Redevelopment project that included line-item descriptions of cost by component, such as building, garage space, and yard space.⁵¹⁴ The Commission notes that EPCOR explained it has or will use an RFP process to select the contractors for the work completed as part of this project. In addition, the purchase price of building 3 at the NSC location was based on independent, third-party market appraisals completed on behalf of both EPCOR and the seller. Purchasing the adjoining property and building also facilitated the expansion and redevelopment of the existing NSC site.

461. EPCOR conducted an alternative analysis, which considered four additional options that could address the facility space shortage. Included in the alternative analysis were present value calculations of the life cycle costs and revenue requirements associated with all the options considered. The Commission notes that the Work Centre Redevelopment project had the lowest forecast capital expenditures, NPV life cycle costs, and present value revenue requirement of all options considered.

462. In light of the Commission's findings with respect to the project grouping in Section 5.2.2 of this decision, the Commission does not agree with the CCA's view that the repair and maintenance costs included in the Work Centre Redevelopment project should be removed from the forecast costs. In Section 5.2.2, the Commission directed EPCOR to group the Work Centre Redevelopment project with its North and South Service Centre Life Cycle Replacement project, given that the latter project consists of capital repairs and maintenance work done at EPCOR's NSC and SSC locations, which are the same service centre locations being redeveloped as part of the Work Centre Redevelopment project.

463. Regarding the relocation of EPCOR's field-based training from the STC to the Winterburn site, the Commission considers that the associated costs are reasonable on the basis that EPCOR already owns the land at the Winterburn location and EPCOR has demonstrated that the alternatives of redeveloping its current STC facility or partnering with an outside party were not viable options, given the space requirements and the need for utility specific equipment and instructors.

464. The Commission acknowledges that EPCOR will experience some operating cost savings as a result of no longer leasing space at the SATSC and EPCOR Tower, and consolidating its employees to its NSC and SSC locations. EPCOR demonstrated that these cost savings are expected to begin to be realized in 2016 and 2017.⁵¹⁵ The Commission notes that the lease and direct rent cost savings will be passed on to customers in future rebasing or rate proceedings.

465. EPCOR indicated that there will be an increase in corporate cost allocations as a result of it no longer renting space at EPCOR Tower from its parent company, EUI. This issue was also before the Commission in EPCOR Transmission's 2015 - 2017 TFO tariff application. In Decision 3539-D01-2015, the Commission found that:

344. The Commission agrees with EDTI that Table 26 above demonstrates cost savings from vacating the EPCOR Tower. ... the Commission is not satisfied that the

⁵¹⁴ Exhibit 20407-X0074, Appendix A-22, Attachment 3, forecast capital.

⁵¹⁵ Exhibit 20407-X0196, response to undertaking given by Mr. McNeil to Mr. McNulty at Transcript, Volume 2, page 307.

costs arising from a lower utilization of EPCOR Tower are required for the provision of utility service. Accordingly, EDTI is directed to remove the increased corporate allocation of EPCOR Tower costs associated with the work centre redevelopment project from its 2016 and 2017 revenue requirement.⁵¹⁶

466. Based on the record of this proceeding, it is unclear if the increase in corporate cost allocations associated with EPCOR no longer renting space at EPCOR Tower from its parent company will have an effect on EPCOR's Work Centre Redevelopment project capital tracker and K factor calculation. EPCOR is directed, in its 2015 capital tracker true-up application, to explain this matter and to identify clearly any increased corporate costs associated with EPCOR no longer renting space at EPCOR Tower, allocated to any capital tracker project.

467. The Commission observes that the K factor revenue requirement calculation for the Work Centre Redevelopment project proposed for 2016 and 2017 incorporates the 2013 and 2014 actual capital additions for this project, that were incurred under the I-X mechanism prior to requesting capital tracker treatment and forecast capital additions for 2015. As set out in Section 3 of in this decision, in the absence of any evidence that the 2013 to 2015 capital additions incurred for this project, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

468. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Work Centre Redevelopment project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

469. In Section 6.1.5, the Commission approved an AUF for this project in 2016 and 2017 of \$1.08 million and \$1.71 million, respectively. As explained in that section, the AUF is paid by EPCOR's transmission function to its distribution function for the joint use of an asset, and is an offset to the K factor associated with this project.

6.3.2 IT Hardware Lifecycle Replacements and Additions

470. The IT Hardware Lifecycle Replacements and Additions program is composed of two projects: the Desktop Evergreen project and the Server Hardware/Software Re-Platform project. This is the first time this program is proposed for capital tracker treatment. EPCOR noted that this program was approved in prior cost-of-service tariff applications in Decision 2008-125,⁵¹⁷ Decision 2010-505⁵¹⁸ and 2012-272.⁵¹⁹ EPCOR provided a business case and engineering study for the IT Hardware Lifecycle Replacements and Additions program in Appendix A-23 of this application.

⁵¹⁶ Decision 3539-D01-2015, paragraph 344.

⁵¹⁷ Decision 2008-125: EPCOR Distribution & Transmission Inc., 2007-2009 Distribution Tariff, 2007-2009 Transmission Facility Owners Tariff, Code of Conduct Exemption, Proceeding 14, Application 1558686-1, December 3, 2008.

⁵¹⁸ Decision 2010-505: EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, 2010-2011 Transmission Facility Owner Tariff, Proceeding 437, Application 1605759-1, October 28, 2010.

⁵¹⁹ Exhibit 20407-X0130.02, revised application, paragraphs 605 and 608.

471. The Desktop Evergreen project is an ongoing project consisting of replacing and upgrading obsolete desktop computers, laptops, mobile devices and printers.⁵²⁰ EPCOR considers a device to be obsolete if it is five years in age or older, and if it does not meet the requirements of newer software that employees require to perform their work.⁵²¹ In response to a Commission IR, EPCOR provided support for its five-year obsolescence criteria for computer hardware by way of a report entitled “EDTI Average Service Life Review,” by Gannett Fleming Canada ULC, as filed in Proceeding 1596, EPCOR’s 2012 GTA.⁵²²

472. The Server Hardware/Software Re-Platform project is a one-year project to re-platform the servers used to support key applications onto a new operating system. EPCOR explained that since the current HP UNIX server will not be supported by the vendor after Q2 of 2016 and, therefore, will need to be replaced, an assessment determined that a change from its current UNIX operating system to a Linux operating system is the prudent alternative. EPCOR further supported this conclusion with information regarding a licensing model change made by its primary application database provider that would require the purchase of additional licenses and annual maintenance fees, if EPCOR replaced its servers using its existing HP UNIX platform.⁵²³

473. EPCOR submitted that not proceeding with this program would result in a risk of IT hardware failures, that would limit its ability to maintain system safety and reliability. In addition, for the re-platform project, EPCOR submitted that not proceeding with the project would result in higher IT support costs.⁵²⁴ EPCOR indicated that these capital projects could not have been undertaken in the past as part of a prudent capital maintenance and replacement program, because it would not have been prudent to replace IT hardware prior to it reaching the end of its useful life.⁵²⁵

474. EPCOR’s forecast capital additions for the Desktop Evergreen project were \$0.45 million in 2016 and \$0.41 million in 2017. EPCOR used its aforementioned obsolescence criteria to estimate its hardware requirements and then used the current list price for those items available from EPCOR’s providers selected through an RFP process. The forecast capital additions for the one-year Server Hardware/Software Re-platform project for 2016 of \$0.52 million were derived using the estimated total number of hours required by internal and external resources, based on historical experience from similar projects and prices from existing contractual agreements, to estimate the hardware costs.⁵²⁶

475. In an IR response to the Commission, EPCOR provided the following table setting out the historical lifecycle replacements of IT hardware:

⁵²⁰ Exhibit 20407-X0130.02, revised application, paragraph 606.

⁵²¹ Exhibit 20407-X0073, Appendix A-23, paragraph 8.

⁵²² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-068(d).

⁵²³ Exhibit 20407-X0073, Appendix A-23, paragraphs 17-19 and 22.

⁵²⁴ Exhibit 20407-X0073, Appendix A-23, paragraphs 16 and 24.

⁵²⁵ Exhibit 20407-X0130.02, revised application, paragraph 615.

⁵²⁶ Exhibit 20407-X0073, Appendix A-23, paragraphs 27-28.

Table 20. Quantity of IT hardware items replaced 2008-2017⁵²⁷

Item	2008 actual	2009 actual	2010 actual	2011 actual	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast	2017 forecast
	(Quantity)									
1 Desktops	n/a	82	169	104	143	74	40	188	111	191
2 Laptops & mobile devices	n/a	4	13	50	39	20	11	13	32	41
3 Multifunction printers	n/a	2	7	3	2	1	0	11	35	13
4 Plotter printers	n/a	0	0	0	0	0	3	0	1	0

476. During the hearing, Mr. Reimer explained the reason for the increase in forecast replacements in 2015, 2016 and 2017, compared to 2013 and 2014. With respect to the desktop replacements, Mr. Reimer explained that the cyclical nature of the replacements could be attributed to when the devices were originally purchased, and noted that a recent upgrade to Windows 7 had an effect on the number of replacements given the physical requirements of the hardware needed to support the new operating system. With respect to the printers, Mr. Reimer noted that subsequent to a recent review, many printers were assessed as “ailing or failing,” and therefore were planned for replacement in 2016 and 2017. EPCOR also decided to replace several personal office printers with fewer larger centralized printers for security and cost saving reasons.⁵²⁸

477. Neither the UCA nor the CCA commented on the IT Hardware Lifecycle Replacements and Additions program in their respective arguments and reply arguments.

Commission findings

478. EPCOR requested capital tracker treatment for the IT Hardware Lifecycle Replacements and Additions program on a forecast basis in 2016 and 2017. EPCOR did not apply for capital tracker treatment for this program in 2013, 2014 and 2015. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application. The program was previously approved by the Commission in Decision 2010-505 and Decision 2012-272, dealing with EPCOR’s 2010-2011 and 2012 cost-of-service GTAs, respectively.

479. The Commission has reviewed the business case and engineering study provided by EPCOR and the evidence on the record of this proceeding with respect to EPCOR’s IT Hardware Lifecycle Replacements and Additions program and finds that the information provided by EPCOR supports a finding that the program is required during the 2016-2017 forecast period to maintain service reliability and safety at adequate levels.

480. With respect to the scope, level and timing of this program for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the program for 2016 and 2017 to be reasonable based on the forecast methodologies employed, as described earlier in this section. The Commission has reviewed the costs of the forecast capital additions in light of the evidence supporting these costs, including the forecast methodologies employed, and finds the forecast

⁵²⁷ Exhibit 20407-X0146, Table EDTI-AUC-2015JUN26-068-2.

⁵²⁸ Transcript, Volume 3, page 351, line 19 to page 355, line 9 (Mr. Reimer).

costs to be reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

481. The Commission observes that the K factor revenue requirement calculation for the IT Hardware Lifecycle Replacements and Additions program proposed for 2016 and 2017 incorporates the 2013 and 2014 actual and 2015 forecast capital additions for this program, that were incurred, or forecast to be incurred, under the I-X mechanism prior to requesting capital tracker treatment. As set out in Section 3 of in this decision, in the absence of any evidence that the 2013, 2014 and 2015 capital additions for this program incurred, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

482. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the IT Hardware Lifecycle Replacements and Additions program are reasonable as proposed for 2016 and 2017, subject to the adjustments applicable to all projects set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this program satisfies the project assessment requirement of Criterion 1.

6.3.3 Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes

483. This ongoing life cycle replacement project involves completing civil rebuilds and replacements of Vaults and Manholes on EPCOR's downtown underground network. Although this project is proposed as a new capital tracker, EPCOR pointed out that this project was previously approved in Decision 2010-505 and Decision 2012-272.⁵²⁹ EPCOR provided a business case and an engineering study for the Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes project in Appendix A-24 of the application.

484. EPCOR stated that it is obligated to operate and maintain its system in a safe and reliable manner and to provide and maintain service at adequate levels and in a safe manner and, as such, it is obligated to repair and replace its network vaults and manholes to maintain the safety and reliability of its system.⁵³⁰

485. EPCOR explained that network vaults and manholes must be capable of bearing the loads that pass over them and it replaces or refurbishes network vaults and manholes under this project when any one of its structural elements (roof, walls, or floor) are found to be in poor condition.⁵³¹

486. EPCOR further explained that network vaults are generally inspected twice a year and network manholes every six years. EPCOR also indicated that it determines the need to rebuild and/or replace vaults and manholes based on its ongoing inspection program.⁵³²

487. EPCOR forecast capital additions associated with this project to be \$1.21 million in 2016 and \$1.26 million in 2017, in order to rebuild and replace four vault roofs completely.⁵³³ In

⁵²⁹ Exhibit 20407-X0072, Appendix A-24, paragraphs 1-2.

⁵³⁰ Exhibit 20407-X0130.02, revised application, paragraph 623.

⁵³¹ Exhibit 20407-X0072, Appendix A-24, paragraph 5.

⁵³² Exhibit 20407-X0072, Appendix A-24, paragraphs 11-12.

⁵³³ Exhibit 20407-X0130.02, revised application, paragraph 624.

response to a Commission IR, EPCOR explained that these forecast capital additions are composed of two components. The first component, estimated at \$1 million annually in each of 2016 and 2017, is the capital cost of four vaults at an average cost of \$0.25 million per vault. The second component, estimated at \$0.21 million in 2016 and \$0.26 million in 2017, deals with deteriorated components and additional work.⁵³⁴

488. EPCOR noted that forecast costs for this project are based on its historical cost experience with completing civil work on network vaults and manholes. Specifically, EPCOR explained that the forecast costs are based on its historical actual cost information for similar work in previous years, adjusted to account for the increased costs associated with the implementation of the arc flash and explosion-related safe work practices, and cost estimates for engineering, materials, project management and construction.⁵³⁵

489. EPCOR indicated that this capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program, because refurbishments or replacement is only undertaken when needed. EPCOR further explained that the need for refurbishment or replacement arises when the condition of a network vault or manhole deteriorates to the point where there is a risk to the reliability of EPCOR's distribution system and public safety.⁵³⁶

490. In response to a Commission IR, EPCOR explained the specific locations for vault or manhole roof replacements are determined in the year prior to construction, based on the integrity of the structure and work requirements imposed by the City of Edmonton. EPCOR indicated that vaults or manholes are only rebuilt after it is determined that repairs are no longer sufficient to maintain the vault or manhole in a safe and reliable condition. EPCOR further confirmed that it seeks opportunities to undertake vault rebuilds in conjunction with other construction activities done by the City of Edmonton.⁵³⁷

491. In an IR response to the UCA, EPCOR explained that its capitalization of the expenditures associated with replacement or refurbishment of vaults and manholes is based on its capitalization policy for regulatory accounting purposes. EPCOR provided examples of issues that can affect the design and scope of work. EPCOR further explained that "the increase between 2013 Actual and 2015-2017 Forecast amounts is the result of EDTI incorporating the increase in 2014 Actual capital additions into its historical average forecasting approach, as explained by EDTI in Appendix A-24 (Exhibit 20407-X0072), in the 2015-2017 forecasts."⁵³⁸

492. In response to a Commission IR,⁵³⁹ EPCOR provided the annual number of vault rebuilds and/or replacements, and associated capital additions since 2011, as set out in the table below:

⁵³⁴ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-074(a).

⁵³⁵ Exhibit 20407-X0072, Appendix A-24, paragraphs 17 and 19.

⁵³⁶ Exhibit 20407-X0130.02, revised application, paragraph 630.

⁵³⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-075(a) and (b).

⁵³⁸ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-016(a), (d) and (e).

⁵³⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-074(b).

Table 21. Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes 2011-2017

Description	2011 actual	2012 actual	2013 actual	2014 actual	2015 decision	2016 forecast	2017 forecast
1 Number of vaults/manholes	5	2	1 vault + 1 manhole	3	4	4	4
2 Capital additions (\$ million)	\$0.45	\$0.78	\$0.56	\$1.16	\$1.25	\$1.21	\$1.26
3 Cost per unit (\$ million)	\$0.09	\$0.39	\$0.28	\$0.39	\$0.31	\$0.30	\$0.32

493. Neither the UCA nor the CCA commented on the Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes project in their respective arguments and reply arguments.

Commission findings

494. In its 2013 true-up and 2014-2015 capital tracker forecast applications, EPCOR did not request capital tracker treatment for this project in 2013 and 2014. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application. The project was previously approved by the Commission in Decision 2010-505 and Decision 2012-272,⁵⁴⁰ dealing with EPCOR's 2010-2011 and 2012 GTAs, respectively.

495. In the present application, EPCOR requested capital tracker treatment for the Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes project on a forecast basis in 2016 and 2017.

496. The Commission has reviewed the business case and engineering study provided by EPCOR and the evidence on the record of this proceeding with respect to EPCOR's Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes project and finds that the information provided by EPCOR supports a finding that the project is required during 2016 and 2017 to maintain service reliability and safety at adequate levels.

497. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are \$1.21 million in 2016 and \$1.26 million in 2017.⁵⁴¹ The Commission observes that the 2016 and 2017 forecast costs for this project are generally consistent with the variance explanations provided in the business case for the actual expenditures over the most recent five-year period. The Commission has reviewed the information supporting EPCOR's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable based on its historical cost experience with completing civil work on network vaults and manholes, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

498. The Commission observes that the K factor revenue requirement calculation for the Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes project proposed for 2016 and 2017 incorporates the 2013 to 2014 actual and 2015 forecast capital additions for this project that were incurred, or forecast to be incurred, under the I-X mechanism prior to requesting capital tracker treatment. As set out in Section 3 of in this decision, in the absence of

⁵⁴⁰ Exhibit 20407-X0072, Appendix A-24, paragraph 2.

⁵⁴¹ Exhibit 20407-X0130.02, revised application, paragraph 624.

any evidence that the 2013 to 2015 capital additions for this project incurred, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

499. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.3.4 Switching Cubicle Life Cycle Replacement

500. This ongoing life cycle replacement project consists of replacing switching cubicles that have reached the end of their useful lives. EPCOR explained that this project is required to maintain the safety and reliability of its system. This project is a new capital tracker for 2017. The project has not been included in EPCOR's previous capital tracker applications. However, EPCOR pointed out that this project was previously approved in Decision 2008-125, Decision 2010-505 and Decision 2012-272.⁵⁴² EPCOR provided a business case and an engineering study for the Switching Cubicle Life Cycle Replacement project in Appendix A-25 of the application.

501. EPCOR stated that this project is required to operate and maintain its system in a safe and reliable manner and to provide and maintain service at adequate levels and in a safe manner. Failure to replace switching cubicles that show signs of corrosion could lead to an increased risk to public safety as switching cubicles contain switchgear that is exposed to high-voltage connections.⁵⁴³

502. EPCOR explained that Switching Cubicle Life Cycle Replacement project will involve the replacement of approximately 30 switching cubicles in each of 2016 and 2017 that were identified as requiring replacement by EPCOR's Asset Management Group based on inspection results.⁵⁴⁴ However, only 2017 capital additions, forecast at \$1.52 million, were sufficient to pass the first tier materiality threshold.⁵⁴⁵

503. EPCOR further explained that it employs preventative maintenance inspections and the application of paint and installation of metal skirts to limit rust and extend the life of its cubicles.⁵⁴⁶ EPCOR indicated that it continues to monitor the state of these cubicles through its underground inspection program.⁵⁴⁷

⁵⁴² Exhibit 20407-X0071, Appendix A-25, paragraphs 1-2.

⁵⁴³ Exhibit 20407-X0130.02, revised application, paragraph 655.

⁵⁴⁴ Exhibit 20407- X0071, Appendix A-25, paragraph 4.

⁵⁴⁵ Exhibit 20407-X0130.02, revised application, paragraph 650.

⁵⁴⁶ Exhibit 20407- X0071, Appendix A-25, paragraph 7.

⁵⁴⁷ Exhibit 20407-X0071, Appendix A-25, paragraph 13.

504. EPCOR explained that, consistent with its past practices, forecast costs for this project are based on a three-year normalized average per unit cost of replacement multiplied by the number of cubicles that require replacement, and adjusted for inflation.⁵⁴⁸

505. EPCOR indicated that this capital project could not have been undertaken as part of an O&M solution, because EPCOR identifies switching cubicles that require replacement in its periodic inspections and immediately installs a temporary metal skirt at the bottom of each unit where the level of corrosion present is sufficient to create a safety risk. EPCOR noted that this temporary solution is not an effective long-term solution.⁵⁴⁹ In response to a Commission IR, EPCOR explained that the use of skirting does not restore structural soundness to the switching cubicles, and it is necessary to replace switching cubicles that have rust affecting the structure when identified, with priority given to those cubicles in the most deteriorated state.⁵⁵⁰

506. In response to a Commission IR, EPCOR explained that the deferral of work in 2013 for this project has increased the planned expenditures for 2016 and 2017, increasing the total number of units by 10 and 11 for each year, respectively. However, EPCOR stated that even without deferred work, the Switching Cubicle Life Cycle Replacement project would still meet the first tier materiality threshold for 2017. In addition, had no delay occurred, the project would also have met the threshold for 2016.⁵⁵¹

507. In an IR response to the UCA, EPCOR explained that in 2014 and 2015, the company's capacity to complete its capital program was challenged by the volume of 2013 capital work that was deferred due to capital tracker uncertainty. Because the asset condition and risk associated with switching cubicles can be temporarily mitigated through the installation of a metal skirt, EPCOR determined to allocate resources away from this project to those that could not be temporarily mitigated. Accordingly, the 14 cubicles replaced in 2014 and 2015 were identified as the minimum number requiring immediate replacement at that time, and the remaining switching cubicles were mitigated through temporary application of a metal skirt.⁵⁵²

508. Neither the UCA nor the CCA commented on the Switching Cubicle Life Cycle Replacement project in their respective arguments and reply arguments.

Commission findings

509. In its 2013 and 2014-2015 capital tracker forecast applications, EPCOR did not request capital tracker treatment for this project in 2013 and 2014. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application. The project was previously approved by the Commission in Decision 2008-125, Decision 2010-505 and Decision 2012-272.⁵⁵³

510. In the present application, EPCOR requested capital tracker treatment for the Switching Cubicle Life Cycle Replacement project on a forecast basis in 2017.

⁵⁴⁸ Exhibit 20407-X0071, Appendix A-25, paragraph 19.

⁵⁴⁹ Exhibit 20407-X0130.02, revised application, paragraph 656.

⁵⁵⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-076(b).

⁵⁵¹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-076(a).

⁵⁵² Exhibit 20407-X0155, EDTI-UCA-2015JUN26-018(b).

⁵⁵³ Exhibit 20407-X0072, Appendix A-25, paragraph 2.

511. The Commission has reviewed the business case and engineering study provided by EPCOR and the evidence on the record of this proceeding with respect to EPCOR's Switching Cubicle Life Cycle Replacement project and finds that the information provided by EPCOR supports a finding that the project is required during 2017 to maintain service reliability and safety at adequate levels.

512. With respect to the scope, level and timing of this project for 2017, EPCOR indicated that forecast 2016 and 2017 capital expenditures for this project were affected by the company's delay of planned cubicle replacements in 2013, increasing the total number of units to be replaced by 10 and 11 for each year, respectively.⁵⁵⁴ In Decision 3100-D01-2015, the Commission determined it will not disqualify from capital tracker treatment capital tracker projects delayed in 2013, in whole or in part, because of what EPCOR referred to as the "substantial capital funding shortfall under the I-X mechanism and the uncertainty respecting the capital tracker mechanism." The Commission also stated it will consider for capital tracker treatment the portions of work deferred in 2013.⁵⁵⁵

513. The Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast, scope, level and timing of the project for 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are \$1.52 million in 2017.⁵⁵⁶ The Commission observes that the 2016 and -2017 forecast costs for this project are generally consistent with the variance explanations provided in the business case for the actual expenditures over the most recent five-year period. The Commission found EPCOR's normalized three-year average forecasting methodology to be reasonable in Decision 2012-272.⁵⁵⁷ The Commission has reviewed the information supporting EPCOR's 2017 forecasts and finds the total annual cost forecast to be reasonable based on a three-year normalized average per unit cost,⁵⁵⁸ subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

514. The Commission observes that the K factor revenue requirement calculation for the Switching Cubicle Life Cycle Replacement project proposed for 2017 incorporates the 2013-2014 actual and 2015-2016 forecast capital additions for this project, that were incurred, or forecast to be incurred, under the I-X mechanism prior to 2017. As set out in Section 3 of this decision, in the absence of any evidence that the 2013 to 2016 capital additions for this project incurred, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

515. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Switching Cubicle Life Cycle Replacement project are reasonable as proposed for 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this

⁵⁵⁴ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-076(a).

⁵⁵⁵ Decision 3100-D01-2015, paragraph 116.

⁵⁵⁶ Exhibit 20407-X0130.02, revised application, paragraph 650.

⁵⁵⁷ Decision 2012-272, paragraphs 232-233.

⁵⁵⁸ Exhibit 20407-X0071, Appendix A-25, paragraph 19.

decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.3.5 Network Reconfigurations

516. The Network Reconfigurations project is a new multi-year project consisting of the reconfiguration of EPCOR's 208-volt and 600-volt downtown underground network, with work commencing in 2016. EPCOR is requesting capital tracker treatment for this project in 2017. EPCOR did not request capital tracker treatment of this project in 2016, because the project did not meet the materiality threshold for 2016.⁵⁵⁹ In Appendix A-26 of this application, EPCOR provided a business case and a detailed engineering study that was completed in 2013 by Quanta Technology LLC (Quanta).

517. EPCOR explained that the work for this project is being undertaken primarily to reduce fault levels to address safety concerns. The component of the project to reduce fault levels at two transmission substations that supply the distribution network was proposed in EPCOR's 2015-2017 Transmission tariff application. To address safety concerns on the distribution system (secondary side), consistent with the recommendations made in the Quanta study, EPCOR proposed to reconfigure the 208-volt grid network into smaller networks, and convert the 600-volt spot network transformers to a primary radial system.⁵⁶⁰ EPCOR noted that in 2009, it had suspended all network maintenance programs due to safety concerns until a safe work procedure was implemented. EPCOR emphasized that these procedures have affected reliability because equipment must be de-energized before work is commenced, when the hazard level is too high, and that these "inefficient and restrictive work procedures" have increased the time required for employees to perform construction, maintenance and repair activities.⁵⁶¹ EPCOR proposed to begin this project in 2016 and expects it to be completed by 2023, noting that a phased approach is required to limit the effect of downtown power interruptions.⁵⁶²

518. EPCOR submitted that not proceeding with this project would place the safety and reliability of its downtown network at risk, increase customer outage times and increase safety risks to its employees and the public.⁵⁶³ EPCOR indicated that this capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program, because "network reconfigurations, by its nature, are not an activity that could have been included in such a program in the past."⁵⁶⁴

519. EPCOR forecast capital additions associated with this project at \$3.57 million in 2017. EPCOR stated that capital expenditures for this project were based on historical experience of engineering, materials, and construction costs for similar projects.⁵⁶⁵

520. In its application, EPCOR stated that to address arc flash concerns, Quanta recommended that the high fault levels at two transmission substations be reduced. EPCOR noted that this

⁵⁵⁹ Exhibit 20407-X0130.02, revised application, paragraphs 661-662.

⁵⁶⁰ Exhibit 20407-X0070, Appendix A-26, paragraphs 3-5.

⁵⁶¹ Exhibit 20407-X0070, Appendix A-26, paragraphs 7 and 18.

⁵⁶² Exhibit 20407-X0070, Appendix A-26, paragraph 11.

⁵⁶³ Exhibit 20407-X0070, Appendix A-26, paragraphs 22 and 24.

⁵⁶⁴ Exhibit 20407-X0130.02, revised application, paragraph 669.

⁵⁶⁵ Exhibit 20407-X0070, Appendix A-26, paragraph 27.

project would be included in EPCOR's 2015-2017 Transmission tariff application.⁵⁶⁶ In an IR, the Commission noted that it did not appear that the Quanta engineering study and calculations considered the impact to the distribution system consequent to the completion of the transmission upgrades. In response to the IR, EPCOR stated:

EDTI did not request Quanta to provide revised arc flash calculations for the scenario where transmission upgrades have been completed, prior to starting distribution upgrades, as the system improvements realized by completing the transmission work will only address the arc flash risk on the primary side of the network. It will not address the arc flash risk on the secondary side.⁵⁶⁷

521. During the hearing, EPCOR and Quanta clarified that although EPCOR did not specifically request Quanta to provide revised arc flash calculations, the process that evolved over time resulted in the effect of the substation upgrades being included in the arc flash calculations. In addition, EPCOR submitted that the IR response quoted above was meant to express that the transmission upgrades did not eliminate the risk of an arc flash on the secondary side.⁵⁶⁸

522. During the hearing, in discussion with Commission counsel, the Quanta witness, confirmed that the engineering study did consider the transmission upgrades:

Q. ... gentlemen, did you consider the upgrades to the feeders to the substations when you considered and made your report with respect to the work to be done on the distribution side of the system?

A. DR. SPARE: Yes, we did, because we actually did modelling of the fault current and arc flash energies with the current substation design and with the new substation design and verified that the new substation design significantly improved or reduced arc flash energies, both on the primary side and on the secondary side, particularly in the distributed secondary networks, the 208-volt network.

...
Q. So just to confirm, the impact of the design in the substation was fully considered when you revised your study, and the potential for reduced arc flash risk was incorporated into your final recommendations? Is that correct?

A. DR. SPARE: That's correct.

...
Q. So the study that's filed in this proceeding, which I referred to you earlier, dated March 9th, 2013, and filed as an attachment to the business case, Exhibit 70, that is the final report that you're referring to, the revised study?

A. DR. SPARE: Yes. That is the final report which included the revised calculations.⁵⁶⁹

523. As noted in the exchange below with Commission counsel, Quanta also confirmed that the capital addition forecasts proposed by EPCOR are consistent with the recommendations in the Quanta report. In addition, Quanta provided its opinion on the reasonableness of the project scope, design, timing and costs of the project as proposed by EPCOR.

⁵⁶⁶ Exhibit 20407-X0070, Appendix A-26, paragraph 19.

⁵⁶⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-079(a).

⁵⁶⁸ Transcript, Volume 3, page 448, line 7 to page 449, line 12 and page 451, lines 7-25 (Dr. Spare and Ms. Hull).

⁵⁶⁹ Transcript, Volume 3, pages 446-450.

Q. So the plan they came up with in response to your -- that you originally looked at did not have the benefit of the arc flash recalculations. You subsequently included those in your final report.

And, Mr. Snyder, you indicated you're familiar with the documentation as filed in this proceeding; yes, sir? So does the documentation, the plan, the business case, and the supporting capital addition forecasts, do they correspond and support your final report which would include the revisions to the arc flash calculations?

A. MR. SNYDER: They are consistent with our recommendations.

Q. Your final recommendations?

A. MR. SNYDER: Yes.⁵⁷⁰

...

Q. And to the extent you've looked at this issue, do you consider that the scope and design and the costs are reasonable?

A. MR. SNYDER: To the extent that we've been able to see the information in the business cases, yes.

Q. Thank you. Is there anything that you would want to see more of in order to be more comfortable with determining -- with saying that the scope, design, and cost is reasonable?

A. MR. SNYDER: From a business case, we get a general description of scope and design and cost. Mostly scope. There's very little design information here. It's conceptual design. So from that perspective, again, it's consistent with what we were trying to achieve through your recommendations. We're not privy to EDTI's cost numbers for how they're estimating this. I accept them as being reasonable based on what I know in the industry.⁵⁷¹

...

Q. And, sir, in terms of the timing, given what they're proposing to do for '16 and '17, is that consistent with your recommendations, or would you suggest that it should be accelerated or that it's perhaps being done more quickly than it has to be done?

A. MR. SNYDER: Well, yes, the step -- correct me if I'm wrong here, John. You know the detail much better than I. But the step to convert the 600-volt spot network was something that really was not quite as early in our recommendations as being proposed here. However, the reason for the proposal at this time, more than justifies moving it up in schedule, is simply because of other work that's being required by EDTI for infrastructure work in the city and the proximity of feeders to be able to convert the 600-volt spots to primary select networks.

To me it makes sense and is, in fact, a cost saving recommendation based on the timing of other work that's required.⁵⁷²

524. Neither the UCA nor the CCA commented on the Network Reconfigurations project in their respective arguments and reply arguments.

Commission findings

525. EPCOR requested capital tracker treatment for the Network Reconfigurations project on a forecast basis in 2017. EPCOR did not apply for capital tracker treatment for this program in 2016, because the program did not meet the first tier of the materiality threshold for 2016.

⁵⁷⁰ Transcript, Volume 3, page 456, lines 6-20 (Mr. Snyder).

⁵⁷¹ Transcript, Volume 3, page 458, line 1 to page 459, line 13 (Mr. Snyder).

⁵⁷² Transcript, Volume 3, page 459, line 15 to page 460, line 8 (Mr. Snyder).

526. The Commission has reviewed the business case and engineering study provided by EPCOR and the evidence on the record of this proceeding with respect to EPCOR's Network Reconfigurations project, and finds that the information provided by EPCOR supports a finding that the project is required during the 2017 forecast period to maintain service reliability and safety at adequate levels.

527. With respect to the scope, level and timing of this project for 2017, the Commission has reviewed the business case and the relevant portions of the record for this project. In particular, the Commission has relied on the filed and oral opinion evidence provided by the Quanta engineering consultants, which supported the scope, level, timing and forecast costs of the project as proposed by EPCOR. The Quanta evidence was not contested by the intervenor parties. The Commission finds the forecast scope, level and timing of the project for 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are \$3.57 million in 2017, subject to the adjustments applicable to all projects set out in Section 6.1 of this decision.

528. The Commission observes that the K factor revenue requirement calculation for the Network Reconfigurations project proposed for 2017 incorporates 2015 and 2016 forecast capital additions for this program, that were incurred, or forecast to be incurred, under the I-X mechanism prior to 2017. As set out in Section 3 of in this decision, in the absence of any evidence that the 2015 and 2016 capital additions for this project incurred, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

529. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Network Reconfigurations project are reasonable as proposed for 2017, subject to the adjustments applicable to all projects set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this program satisfies the project assessment requirement of Criterion 1.

6.3.6 Street Light Service Connections and Security Lighting Addition and Capital Replacement

530. This ongoing growth and life cycle replacement project consists of providing street lighting, signal and security lighting customers with safe and reliable service connections. Costs included in completing capitalized repairs or additions to EPCOR-owned security lighting systems are included in this capital tracker project.⁵⁷³ EPCOR provided business cases and engineering studies for the Street Light Service Connections and Security Lighting Additions and Capital Replacements project in Appendix A-21 of the application.

531. During the hearing, Ms. Hull explained the project as follows:

This project is basically two components. Has a growth component and a life cycle component. The growth component would be hooking up new streetlights, new signals, and new bus shelters for the new neighbourhoods that are being built in and around the Edmonton area.

⁵⁷³ Exhibit 20407-X0076, Appendix A-21, paragraph 1.

The life cycle component is for the repair and life cycle replacement of our security lighting system. And this is a system that EDTI kept when we separated from the City. And it's basically all the unmetered lights in parks, walkways, sometimes in parking lots of community centres, these sorts of things.⁵⁷⁴

532. EPCOR noted that in Decision 3100-D01-2015, the Commission found this project satisfied the project assessment component of Criterion 1. However, EPCOR explained that through the course of the 2013-2015 capital tracker compliance filing, this project no longer met the materiality threshold for 2015 and thus, did not qualify for capital tracker treatment in that year as set out in the compliance filing Decision 20210-D01-2015.⁵⁷⁵

533. EPCOR is applying for capital tracker treatment for this project in 2017. Forecast capital additions for 2016 do not meet the first tier of the materiality threshold.⁵⁷⁶ Forecast capital additions associated with this project in 2017 are \$0.58 million in 2017. EPCOR explained that the forecast for the street light service connections component of the project was based on the normalized three-year average of the historical average of the actual capital additions associated with such service connections from 2012 to 2014, and capital additions for the security lighting component of the project have been forecast based on 2014 actuals. A new project management program implemented in 2014 has created efficiencies and improved the engineering review process.⁵⁷⁷

534. EPCOR noted that the primary costs included in EPCOR's forecast for this project are costs associated with engineering, construction and the preparation of as-built drawings of new unmetered service connections or replacement assets.⁵⁷⁸

535. During the hearing, the Commission sought explanation regarding the forecasting methodology for capital additions for the security lightning portion of the project being based on 2014 actuals. Ms. Hull explained that prior to 2014, it would have been based on the three-year historical average for security lightning, and the three-year historical actuals would have been higher than the forecast for 2016. EPCOR utilized 2014 actual results because it had implemented a new project management program for this project in that year. Ms. Hull confirmed that other than the efficiencies discussed in the business case, there were no other changes to the scope, level, or timing of this project since it was last approved.⁵⁷⁹

536. In undertakings given by EPCOR to the Commission, EPCOR provided the three-year normalized average forecast for 2016 and 2017 for security lighting only and the forecast for 2016 and 2017, separated between street light service connections and security lighting.⁵⁸⁰

537. Neither the UCA nor the CCA commented on the Street Light Service Connections and Security Lighting Additions and Capital Replacements project in their respective arguments and reply arguments.

⁵⁷⁴ Transcript, Volume 3, page 403, line 25 to page 404, line 11 (Ms. Hull).

⁵⁷⁵ Exhibit 20407-X0130.02, revised application, paragraph 637.

⁵⁷⁶ Exhibit 20407-X0130.02, revised application, paragraph 638.

⁵⁷⁷ Exhibit 20407-X0076, Appendix A-21, paragraph 14.

⁵⁷⁸ Exhibit 20407-X0076, Appendix A-21, paragraph 4.

⁵⁷⁹ Transcript, Volume 3, page 404, line 16 to page 405, line 5, page 407, lines 5-18 (Ms. Hull).

⁵⁸⁰ Exhibit 20407-X0201, Undertaking 201, Exhibit 20407-X0202, Undertaking 202.

Commission findings

538. In Decision 3100-D01-2015,⁵⁸¹ the Commission approved the need for the Street Light Service Connections and Security Lighting Additions and Capital Replacements project for purposes of capital tracker treatment for 2015. This project was also approved in prior decisions dealing with EPCOR's cost-of-service tariff applications.⁵⁸² EPCOR continued with this project in the 2013 to 2015 period.⁵⁸³ Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project, when proposed previously for capital tracker treatment, were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1. However, this project was not afforded capital tracker treatment in 2015 because it did not meet the requirements of other capital tracker criteria on a forecast basis, as set out in the compliance filing Decision 20210-D01-2015, Table 4.

539. In its 2014-2015 capital tracker forecast application, EPCOR did not request capital tracker treatment for this project in 2014, because the project did not meet the first tier of the materiality threshold for 2014 on a forecast basis. EPCOR also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application.

540. In the present application, EPCOR requested capital tracker treatment for this project on a forecast basis in 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Street Light Service Connection and Security Lighting Addition and Capital Replacement project is not required to continue in 2017.

541. With respect to the scope, level and timing of this project for 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2017 to be reasonable. EPCOR's forecast capital additions associated with this project are 0.58 million in 2017.⁵⁸⁴ The Commission found EPCOR's normalized three-year average methodology to be reasonable in Decision 2012-272.⁵⁸⁵ The Commission has reviewed the information supporting EPCOR's 2017 forecasts and finds the total annual cost forecasts to be reasonable based on the normalized three-year average of the actual costs associated with this project from 2012 to 2014 for street light service connections, and 2014 actuals for security lightning, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

542. The Commission observes that the K factor revenue requirement calculation for the Street Light Service Connections and Security Lighting Addition and Capital Replacement project proposed for 2017 incorporates the 2013 to 2014 actual and 2015 and 2016 forecast capital additions for this project, that were incurred, or forecast to be incurred, under the I-X mechanism

⁵⁸¹ Decision 3100-D01-2015, paragraph 549.

⁵⁸² Exhibit 20407-X0130.02, revised application, paragraph 637.

⁵⁸³ Exhibit 20407-X0076, Appendix A-21, Table 3.2-1 on page 4.

⁵⁸⁴ Exhibit 20407-X0130.02, revised application, paragraph 638.

⁵⁸⁵ Decision 2012-272, paragraphs 232-233.

prior to 2017. As set out in Section 3 of this decision, in the absence of any evidence that the 2013, 2014, 2015 and 2016 capital additions for this project incurred, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2016 and 2017 forecast costs.

543. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Street Light Service Connections and Security Lighting Additions and Capital Replacements project are reasonable as proposed for 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.4 Customer revenue metering program

544. In Section 5.2.1 of this decision, the Commission directed EPCOR to group the Customer Revenue Metering – Growth & Life Cycle Replacements project and the AMI project together under a single Customer Revenue Metering program. As discussed in that section, during the 2015 to 2017 period, the type of meter to be installed under each of these projects will be AMI meters. Starting in the second half of 2015, EPCOR began installation of AMI meters for both growth and normal course replacement purposes under the Customer Revenue Metering – Growth & Life Cycle Replacements project, discussed in Section 6.4.1. The mass replacement of existing meters with AMI meters will be undertaken from 2015 to 2017 as part of the AMI project, discussed in Section 6.4.2 of this decision.

6.4.1 Customer Revenue Metering – Growth & Life Cycle Replacements

545. This ongoing project consists of installing revenue meters at new sites and replacing meters at existing sites that are no longer compliant with Measurement Canada requirements. EPCOR explained that this project is required to ensure that each site in its service area has an accurate, functional meter that meets the requirements of the *Electricity and Gas Inspection Act and Regulations*.⁵⁸⁶

546. The issues discussed in this proceeding related to this project can be broadly divided into two areas. The first area deals with the need for the project, the prudence of the 2014 actual expenditures and the reasonableness of the 2016 and 2017 forecast expenditures associated with this project, including considerations of project scope, level and timing, which form the project assessment under capital tracker Criterion 1. These issues are addressed in Section 6.4.1.1. The second area relates to EPCOR's proposal to include in the revenue requirement calculations for this project for K factor purposes, the accelerated depreciation amounts for the non-AMI meter assets. This matter will be addressed in Section 6.4.1.2 for ease of reference.

⁵⁸⁶ R.S.C., 1985, c. E-4, Exhibit 20407-X0130.02, revised application, paragraph 501.

6.4.1.1 The need for the project, project scope, level and timing, 2014 actual expenditures and 2016-2017 forecast expenditures

547. EPCOR noted that this project was afforded capital tracker treatment on an actual basis for 2013 and on a forecast basis for 2014 and 2015, as approved in Decision 3100-D01-2015.⁵⁸⁷ EPCOR provided a business case and an engineering study for the Customer Revenue Metering – Growth & Life Cycle Replacements project in Appendix A-16 of the application.

548. As set out in Decision 3100-D01-2015, EPCOR's expenditures associated with this project have been impacted by changes to the Measurement Canada's meter testing requirements. Specifically, from 1988 until 2011, Measurement Canada specification LMB-EG-04 governed compliance sample testing. In 2011, Measurement Canada introduced a new compliance specification, S-S-06, which became effective for electronic meters in that year. Effective in 2014, Measurement Canada specification S-S-06 applies to all electricity meters, including the older-technology electro-mechanical meters that make up the bulk of EPCOR's meter population. In addition, *The Fairness at the Pumps Act*,⁵⁸⁸ which came into force on August 1, 2014, introduces financial penalties for inaccurate measuring devices and allows Measurement Canada to impose penalties based on a number of factors, including assessing the likelihood that meters fail testing under Measurement Canada specification S-S-06.⁵⁸⁹

549. EPCOR noted that the new Measurement Canada requirements increased the number of meters subjected to compliance testing. The application of these more stringent criteria resulted in an increase in the number of meters that failed testing and required replacement.⁵⁹⁰ EPCOR indicated that the change from LMB-EG-04 to S-S-06 had a marked effect on its compliance sampling program in 2014.

550. In Decision 3100-D01-2015, the Commission approved forecast capital additions for this project in the amount of \$4.79 million for 2014, reflective of the S-S-06 compliance specification requirements. EPCOR's actual capital additions for this project were \$5.36 million, for a positive variance of \$0.57 million. EPCOR explained that this variance was primarily caused by differences between the forecast and actual number of meter installations and replacements.⁵⁹¹

551. Regarding meter unit costs in 2014, EPCOR explained that the supplier of its electro-mechanical meters was originally designated through a request for quotations in 2009 for two years. The contract pricing was later extended to the end of 2014 because the supplier had Measurement Canada approved meters and could supply them at a lower cost than other competitors.⁵⁹² In response to a Commission IR, EPCOR indicated that it subsequently negotiated a contract extension to the end of 2015 that guarantees supply of non-AMI meters until procurement of AMI meters begins in the third quarter of 2015. EPCOR also stated that prior to extending the contract, EPCOR surveyed the market in 2013, and verified that its contract pricing for non-AMI meters was the lowest available in the market.⁵⁹³

⁵⁸⁷ Exhibit 20407-X0130.02, revised application, paragraph 356.

⁵⁸⁸ S.C. 2001, c. 3.

⁵⁸⁹ Decision 3100-D01-2015, paragraphs 506-507.

⁵⁹⁰ Exhibit 20407-X0130.02, revised application, paragraph 504.

⁵⁹¹ Exhibit 20407-X0088, Appendix A-16, paragraph 41.

⁵⁹² Exhibit 20407-X0088, Appendix A-16, paragraph 32.

⁵⁹³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-044(a) and (b).

552. EPCOR forecast capital additions associated with this project to be \$4.18 million in 2016 and \$3.86 million in 2017.⁵⁹⁴ These forecast capital expenditures were based on the forecast number of meters to be installed or replaced multiplied by the forecast installation cost per meter, which includes the engineering, labour, materials, and vehicle costs associated with the installation. This forecast was also reflective of EPCOR's decision to proceed with the AMI project, described in Section 6.4.2. Specifically, EPCOR noted the activities comprising the Customer Revenue Metering – Growth & Life Cycle Replacements project in 2016 and 2017 will differ in several important respects from previous years.

553. EPCOR indicated that all new revenue meters installed as part of this project in 2016 and 2017 for both growth and replacements will be AMI meters. In response to a Commission IR, EPCOR confirmed that it has not forecast the installation of any non-AMI meters during the 2016-2017 period.⁵⁹⁵ As explained in Section 6.4.2.3, EPCOR's pricing of the AMI meters and related assets was obtained through a competitive bidding process. Regarding the volume component of the forecast, EPCOR indicated that for 2016 and 2017, the number of new revenue meters forecast to be installed at new sites is based on the average of the actual number of new installs for the years 2012 to 2014.⁵⁹⁶

554. With respect to the life cycle replacement of meters at existing sites, EPCOR noted that the main cost drivers in meter life-cycle replacements are the number of meters that the company is obligated to test in a particular year, and the specific mix of meter types to be tested. EPCOR indicated it would apply to Measurement Canada in 2015 for temporary dispensation from S-S-06 meter sample testing and replacement requirements, recognizing that it would be pointless for the company to test or replace meters that are subject to imminent replacement with new AMI meters. As further discussed below, in its argument, EPCOR indicated that it "has in the near term been able to obtain dispensation from Measurement Canada to avoid what would have otherwise been a substantial testing and replacement program in 2014 through 2017."⁵⁹⁷ EPCOR's 2016 and 2017 forecast of meter replacements was based on the assumption that its request for dispensation would be granted.⁵⁹⁸ As a result, the forecast volume of meter replacements required for compliance sampling and for accuracy reverification was substantially reduced as compared to previous years. For example, EPCOR forecast to replace 359 meters for sample testing in 2016 and 0 meters in 2017, as compared to 4,688 meters actually replaced for sample testing in 2014.⁵⁹⁹

555. At the same time, EPCOR pointed out that the change from electro-mechanical to electronic meters by the industry has resulted in a shorter life-span for meters than was observed historically. Although electronic meters equal or exceed the accuracy of electro-mechanical meters, they are more susceptible to catastrophic failure after exposure to temperature fluctuations over several years. EPCOR also indicated that electronic meters that have not failed catastrophically, but are out of tolerance, are still problematic because Measurement Canada rules currently prevent servicing of electronic meters by meter owners. Therefore, EPCOR stated

⁵⁹⁴ Exhibit 20407-X0088, Appendix A-16, Table 3.3-1 on page 9.

⁵⁹⁵ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-043(a).

⁵⁹⁶ Exhibit 20407-X0088, Appendix A-16, paragraph 22.

⁵⁹⁷ Exhibit 20407-X0233, EPCOR argument, paragraph 224.

⁵⁹⁸ Exhibit 20407-X0088, Appendix A-16, paragraphs 12-16.

⁵⁹⁹ Exhibit 20407-X0088, Appendix A-16, Table 2.2-1 on page 4.

it is generally more cost-effective to scrap malfunctioning electronic meters and replace them with new meters.⁶⁰⁰

556. With the exception of the capitalized inspection costs related to the installation of new meters and service connections included in this project, addressed in Section 6.1.2 of this decision, no party took issue with EPCOR's 2014 actual or 2016 and 2017 forecast capital additions for this project. The UCA specifically clarified that it did not oppose the approval of the Customer Revenue Metering – Growth & Life Cycle Replacements project, in principle, provided it meets other capital tracker criteria.⁶⁰¹ However, both the UCA and the CCA objected to the inclusion of accelerated depreciation amounts for the electro-mechanical and automated meter reading (AMR) metering assets associated with this project in the K factor calculation. This issue is addressed in Section 6.4.1.2 of this decision.

Commission findings

557. In Decision 3100-D01-2015,⁶⁰² the Commission approved the need for the Customer Revenue Metering – Growth & Life Cycle Replacements project for purposes of capital tracker treatment on an actual basis for 2013 and on a forecast basis for 2014 and 2015. Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1. In addition, in Decision 3100-D01-2015, and in the compliance filing Decision 20210-D01-2015 in relation thereto, the Commission approved the actual scope, level, timing and costs of this project, included in the 2013 capital tracker true-up application, as prudent.

558. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Customer Revenue Metering – Growth & Life Cycle Replacements project was not required in 2014.

559. With respect to the scope, level and timing of the project carried out in 2014, the Commission has reviewed EPCOR's 2014 actual capital additions of \$5.36 million associated with this project, and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for this capital tracker and approved in Decision 3100-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this project, other than the cost and adjustments addressed above, in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds that there is no evidence that these costs are not reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. However, the Commission cannot fully evaluate the prudence of the 2014 actual costs without first obtaining the clarification below.

⁶⁰⁰ Exhibit 20407-X0088, Appendix A-16, paragraph 17.

⁶⁰¹ Exhibit 20407-X0236, UCA reply argument, paragraph 31.

⁶⁰² Decision 3100-D01-2015, paragraph 523.

560. As referenced in Decision 3100-D01-2015, in the 2014-2015 capital tracker application, EPCOR indicated that, unlike the 2015 forecast costs, the 2014 forecast total capital additions for the Customer Revenue Metering – Growth & Life Cycle Replacements project were not dependent on approval of the AMI project:

512. EDTI explained that its 2015 forecasts assume approval of the AMI project. In 2014, the forecast total capital additions for the Customer Revenue Metering – Growth & Life Cycle Replacements project are \$4.79 million, regardless of whether the AMI project is approved. In 2015, however, if the AMI project is approved, the forecast capital additions for customer revenue metering are \$4.19 million. If the AMI project is not approved, EDTI forecast the 2015 capital additions to be \$5.85 million.

513. The difference arises because, if the AMI project is approved, EDTI will be able to apply for dispensation from the new Measurement Canada specification S-S-06, given that it would be replacing existing meters that would otherwise require testing, with new meters as part of the AMI project. Approval of the AMI project would result in the number of meters that require testing, as part of the Customer Revenue Metering–Growth & Life Cycle Replacements project, to be limited to meters that are tested individually and not as part of a larger group, or are damaged and suspected of failure. If the AMI project is not approved, more meters will require replacement as a result of sample testing under Measurement Canada specification S-S-06, which will result in a higher cost.⁶⁰³ [footnotes omitted]

561. In the business case for this project as part of this application, EPCOR indicated it was “in the process of applying for” Measurement Canada’s program for temporary dispensation from meter reverification. EPCOR appeared to be consistent with its evidence in Proceeding 3100 and indicated that Measurement Canada’s dispensation will affect its costs for this project from 2015 onwards:

In 2015, as noted above, EDTI will apply to Measurement Canada for dispensation from S-S-06 meter sample testing and replacement requirements, recognizing that it would be pointless for EDTI to test or replace meters which are subject to imminent replacement with new AMI meters. Replacements in 2015-2017 will be reduced to only those meters which must be individually tested (as they do not belong to a larger group which can be sample tested) or which must be replaced due to damage or suspected failure.⁶⁰⁴

562. However, in its argument, EPCOR appeared to suggest that the 2014 actual costs for this project may have been affected by its decision to proceed with the AMI project as well:

As described in detail in Appendix A-16, in the absence of EDTI’s proposed AMI project, these new requirements mandated that EDTI test and replace a substantially higher number of existing meters on its system beginning in 2014 and 2015 and carrying forward into future years. By moving forward with the AMI project, EDTI has in the near term been able to obtain dispensation from Measurement Canada to avoid what would have otherwise been a substantial testing and replacement program in 2014 through 2017.⁶⁰⁵

⁶⁰³ Decision 3100-D01-2015, paragraphs 512-513.

⁶⁰⁴ Exhibit 20407-X0088, Appendix A-16, paragraph 16.

⁶⁰⁵ Exhibit 20407-X0233, EPCOR argument, paragraph 224.

563. The Commission directs EPCOR, in its compliance filing to this decision, to explain the extent to which its 2014 actual costs for the Customer Revenue Metering – Growth & Life Cycle Replacements project were affected by its decision to proceed with the AMI project, including any effect of Measurement Canada’s dispensation. Additionally, EPCOR is directed to explain, in the compliance filing, with supporting documentation, the terms of the Measurement Canada dispensation including timing and scope (i.e., type and number of meters subject to the obtained dispensation).

564. In the present application, EPCOR also requested capital tracker treatment for the Customer Revenue Metering – Growth & Life Cycle Replacements project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that this project is not required to continue in 2016 or 2017.

565. With respect to the scope, level and timing of this project for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016 and 2017 to be reasonable. Inclusive of capitalized inspection costs related to the installation of new meters and service connections, EPCOR’s forecast capital additions associated with this project are \$4.18 million in 2016 and \$3.86 million in 2017.⁶⁰⁶ EPCOR’s 2016 and 2017 forecast of meter replacements was reflective of EPCOR’s decision to proceed with the AMI project and was reduced as compared to previous years, based on the assumption that its request for dispensation from Measurement Canada’s compliance specification S-S-06 would be granted.⁶⁰⁷ The Commission has reviewed the information supporting EPCOR’s 2016 and 2017 forecasts and finds the total annual cost forecast to be reasonable based on the forecast number of new meters and meter replacements to be installed in 2016 and 2017, as outlined in its forecast methodology,⁶⁰⁸ subject to removing capitalized inspection costs related to the installation of new meters and service connections and subject to the other adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

566. Given the above, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the Customer Revenue Metering – Growth & Life Cycle Replacements project are reasonable as proposed for 2016 and 2017, subject to removing capitalized inspection costs related to the installation of new meters and service connections, and the other adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

⁶⁰⁶ Exhibit 20407-X0088, Appendix A-16, Table 3.3-1 on page 9.

⁶⁰⁷ Exhibit 20407-X0088, Appendix A-16, paragraphs 12-16.

⁶⁰⁸ Exhibit 20407-X0088, Appendix A-16, paragraph 27.

6.4.1.2 Accelerated retirement of non-AMI meters

567. In Decision 2012-237, the Commission provided the following direction for the K factor rate adjustment calculation:

977. The calculation of the K factor rate adjustments will be similar to revenue requirement calculations under cost of service, except that the calculation will be limited to the depreciation, taxes and return associated with the incremental rate base for the expenditures that form the capital tracker...⁶⁰⁹

568. EPCOR proposed to include in the forecast revenue requirement calculations for the Customer Revenue Metering – Growth & Life Cycle Replacements capital tracker project for 2016 and 2017, an accelerated depreciation of the non-AMI meter assets. The accelerated depreciation amounts are intended to recover a significant portion of the remaining undepreciated capital investment in the non-AMI meter assets, which totals approximately \$11.5 million.⁶¹⁰ The 2016 and 2017 K factor amounts of \$4.60 million and \$2.30 million associated with this project, respectively (as shown in Table 2 from Section 4 of this decision), were reflective of the proposed accelerated depreciation of the non-AMI meters. The balance of the \$11.5 million was intended to be collected in conjunction with EPCOR's 2015 capital tracker true-up proceeding.

569. As part of its 2012 GTA, EPCOR included a report by Gannett Fleming Canada ULC providing a review of the reasonableness of asset service lives used to calculate depreciation.⁶¹¹ In that report, Gannett Fleming recommended that EPCOR reduce its 25-year average service life for analog meters to 20 years. Furthermore, Gannett Fleming recommended to develop a new account to capture the investment in digital meters, for which a 15-year average service life was recommended. In Decision 2012-272, the Commission accepted the implementation of these proposed changes in asset service lives on a prospective basis, starting in 2012.⁶¹²

570. In its 2014-2015 capital tracker application, EPCOR had reflected the continued recovery of its capital investment in existing electro-mechanical and AMR meters (referred to as “conventional,” or “non-AMI” meters) over their remaining average service life for depreciation purposes (approximately 17 years). In Decision 3100-D01-2015, the Commission observed that the implementation of the AMI project will result in the wholesale retirement of the majority of existing non-AMI meters on EPCOR's system. The Commission determined, based on the principles set out in its Utility Asset Disposition (UAD) Decision 2013-417⁶¹³ and Decision 2014-297⁶¹⁴ dealing with ATCO Electric's Slave Lake assets, that the early retirement of EPCOR's conventional meters constituted an “extraordinary retirement,” in the terminology of

⁶⁰⁹ Decision 2012-237, paragraph 977.

⁶¹⁰ Exhibit 20407-X0233, EPCOR argument, paragraph 286.

⁶¹¹ Proceeding 1596, Exhibit 0077.00.EDTI-1596, Appendix G-1, EDTI Average Service Life Review Gannett Fleming.

⁶¹² Decision 2012-272, paragraph 193.

⁶¹³ Decision 2013-417: Utility Asset Disposition: Proceeding 20, Application 1566373-1, November 26, 2013.

⁶¹⁴ Decision 2014-297: ATCO Electric Ltd., 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 2682, Application 1609719-1, October 29, 2014. Decision 2014-297 (Errata) issued January 8, 2015.

the UAD decision, with the result that the book value of the undepreciated meters would accrue to EPCOR's shareholder rather than customers if the project proceeded as planned.⁶¹⁵

571. In this application, EPCOR retained depreciation expert Mr. Larry Kennedy of Gannett Fleming to provide an updated depreciation study taking into account the specific reduction in service life of EPCOR's conventional meters, given the company's decision to proceed with the AMI project and the resulting known life-span for the conventional meters.

572. In its study, included as Appendix D to the application,⁶¹⁶ Gannett Fleming pointed out that in Alberta, the electric utilities regulated by the AUC are required to comply with the "Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the Provisions of the Alberta Energy and Utilities Board Act, the Electric Utilities Act and the Hydro & Electric Energy Act of Alberta" (USoA). Gannett Fleming continued:

The USoA makes it clear that the depreciation life of assets must match the period of time over which the assets are in service. In depreciation practice this is accomplished through the estimation of the physical remaining life of the assets. Common practice as indicated by the definition of depreciation includes the estimation of retirements caused by many forces of retirement including technological change and opportunities to replace assets to reduce costs for customers. It is through the estimation of these forces of retirement that the estimated remaining life of each group EPCOR Distribution & Transmission Inc. 2015 Depreciation Study of assets can be determined. It is also common that large scale retirement of large groups of assets may occur at one or a small number of points in time, commonly referred to as a life span date...⁶¹⁷

573. In this regard, Gannett Fleming explained that where it is anticipated that all the assets with a particular account or group of accounts will retire at a single point in time, remaining life calculations used in the calculation of depreciation rates can be determined through the use of a life span approach to depreciation. In this case, the term "life span" refers to a period of time from a reference point (typically the date of installation) to the date where all the assets in a group will be retired.⁶¹⁸

574. Gannett Fleming stated that the life span approach "has been widely used and recognized by regulatory bodies in Alberta and other jurisdictions in North America."⁶¹⁹ In response to a Commission IR, Gannett Fleming provided excerpts from "two of the most commonly referred to textbooks (and manuals) on the preparation of depreciation studies" demonstrating that the use of the life span approach is an established and accepted depreciation practice.⁶²⁰

575. Gannett Fleming indicated that based on a discussion with "EPCOR metering representatives," a life span date for conventional meters of December 31, 2017 was developed:

⁶¹⁵ Decision 3100-D01-2015, paragraph 691.

⁶¹⁶ Exhibit 20407-X0004, Appendix D, 2015 Depreciation Study.

⁶¹⁷ Exhibit 20407-X0004, Appendix D, 2015 Depreciation Study, pages 2-3.

⁶¹⁸ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-046, PDF page 211, excerpt from the textbook "*Depreciation Systems*" by Frank K. Wolf and W. Chester Fitch, published in 1994 by the Iowa State University Press, Ames, Iowa.

⁶¹⁹ Exhibit 20407-X0004, Appendix D, 2015 Depreciation Study, page 3.

⁶²⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-046(a).

The EPCOR metering representatives has indicated that the meter replacements will be undertaken on an area by area basis, with specific areas being targeted as a test in 2015. In the years 2016 and 2017, the targeted areas will be replaced on a systematic basis in order to best utilize the replacement crews. As such, it is not possible to identify the specific meters to be retired in any given year, however, the total number of meters to be retired each year can be estimated. In these circumstances, Gannett Fleming recommends the incorporation of a life span date ending at December 31, 2017. In this manner the EPCOR investment in conventional meters will be fully recovered over the asset's life, in accordance with Section 18A of the USoA. It is also noted that any investment not anticipated to be retired will continue to depreciate over the previously approved average service life.⁶²¹

576. Accordingly, Gannett Fleming calculated accelerated annual depreciation accrual rates that result in a complete depreciation of conventional meters by the December 31, 2017, life span date. At the same time, Gannett Fleming noted that the investment in the EPCOR 370 series of accounts, composed of metering assets, includes not only the conventional meters that will be subject to a retirement program but also a significant amount of investment that will remain in service beyond 2017, such as conventional meters not currently in service and not subject to replacement by AMI meters, meter service connections, and other meters.⁶²² In these circumstances, Gannett Fleming recommended that development of a sub-account that includes only the investment related to the conventional meters that will be retired by December 31, 2017. It is this newly created subset of the conventional metering accounts that was the subject of the proposed accelerated depreciation rates.

577. Table 22 below provides the depreciation amounts for each of the years 2015 through 2017, and the related impact on the K factor portion associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project for 2016 and 2017, calculated under EPCOR's previously approved 20-year average service life for these assets, as compared to Gannett Fleming's recommended accelerated depreciation approach.

Table 22. Depreciation and K factor amounts associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project, 2015-2017⁶²³

	Depreciation and K factor amounts	2015	2016	2017
		(\$ million)		
1	Original depreciation expense	0.85	0.83	0.82
2	Accelerated depreciation expense	4.45	4.71	2.36
3	Depreciation variance (row 2 - row 1)	3.60	3.88	1.54
4	Portion of the K factor reflecting original depreciation expense	--	1.08	1.30
5	Portion of the K factor reflecting accelerated depreciation expense	--	4.60	2.30
6	K factor variance (row 5 - row 4)	[Note 1]	3.52	1.00

Note 1: The 2015 K factor amounts are not a subject of this application.

⁶²¹ Exhibit 20407-X0004, Appendix D, 2015 Depreciation Study, page 5.

⁶²² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-045(b).

⁶²³ Exhibit 20407-X0130.02, revised application, Table 3.1.16-1 on page 170 and exhibits 20407-X0213, 20407-X0214 and 20407-X0215.

578. Mr. Shymanski⁶²⁴ and Mr. Thygesen,⁶²⁵ representing the UCA and the CCA, respectively, did not dispute the fact that, in principle, the use of the life span method is an accepted depreciation practice and did not question the accelerated depreciation rates calculated by Gannett Fleming. However, they expressed a number of other concerns with EPCOR's proposal for the accelerated depreciation of conventional meters.

579. In his evidence for the UCA, Mr. Shymanski expressed concern that the Gannett Fleming depreciation report was limited to an examination of one asset class only. Mr. Shymanski indicated that throughout his work experience, he has not seen an analysis of one asset account in isolation from all other asset accounts. Further, this approach was not consistent with the past practice of Mr. Kennedy of Gannett Fleming in Alberta. Mr. Shymanski expressed his view that the Gannett Fleming 2015 depreciation report could not be called a "depreciation study." Mr. Shymanski, however, could not point to a regulatory decision or paper authored by a recognized depreciation expert stating that a single asset depreciation study was not appropriate.⁶²⁶

580. Mr. Shymanski also pointed to paragraph 606 of Decision 3100-D01-2015, where the Commission stated the following:

606. The UCA recommended that "at the time of the next depreciation study, EDTI move to having the service lives the same for all of the vintages of assets within an asset class." Although the Commission sees merit in considering this recommendation in principle, it is outside the scope of the present proceedings but would be relevant in EDTI's next application that includes a depreciation study. [footnote omitted]

581. Mr. Shymanski stated that "[n]either Mr. Kennedy nor EDTI have addressed this comment, which is now relevant if Mr. Kennedy is presenting his analysis in Appendix D as a depreciation study."⁶²⁷

582. Mr. Shymanski expressed other concerns with limiting a depreciation study to an examination of one asset class only. According to Mr. Shymanski, "the reason for doing a full (or even a partial) depreciation study at one time is to capture the impact of all changes to the lives and/or net salvage ... to ensure the full impact is dealt with at one time."⁶²⁸ However, when questioned at the oral hearing, Mr. Shymanski was not aware of any material effect on other accounts as a result of the proposed change to depreciation rates for EPCOR's conventional metering asset account.⁶²⁹ In addition, Mr. Shymanski pointed out that reviewing depreciation changes on a piecemeal basis results in higher regulatory costs.

583. Based on this evidence, the UCA argued that Gannett Fleming's 2015 depreciation report does not constitute a "true depreciation study" and that the report does not provide a sufficient

⁶²⁴ Exhibit 20407-X0171, UCA-AUC-2015JUL30-004(b) and Transcript, Volume 6, page 962, line 20 to page 963, line 11 (Mr. Shymanski).

⁶²⁵ Exhibit 20407-X0167, CCA-AUC-2015JUL30-003(a) and (b) and Transcript, Volume 5, page 907, line 21 to page 908, line 24 (Mr. Thygesen).

⁶²⁶ Transcript, Volume 6, page 972, lines 3-7 (Mr. Shymanski).

⁶²⁷ Exhibit 20407-X0160, UCA evidence of Mr. Shymanski, page 6.

⁶²⁸ Exhibit 20407-X0160, UCA evidence of Mr. Shymanski, page 4.

⁶²⁹ Transcript, Volume 6, page 978, lines 11-14 (Mr. Shymanski).

basis upon which to accept the accelerated depreciation rates for conventional meters proposed by EPCOR.⁶³⁰

584. In response to the UCA's concerns, Mr. Kennedy in his rebuttal evidence, indicated that he was not aware of any depreciation literature that suggests that a depreciation study must include all asset groups. Mr. Kennedy reviewed the Commission's Minimum Filing Requirements established in Bulletin 2006-25,⁶³¹ as they relate to depreciation; as well as other depreciation-related documents and publications by other regulators and the industry, and found no requirement that a depreciation study must include all asset accounts. In addition, Mr. Kennedy referred to precedents where utilities have filed depreciation studies that have not included all accounts. Mr. Kennedy acknowledged that Gannett Fleming had not done a single stand-alone asset study before.

Q. You may have indirectly answered this yesterday, but has Gannett Fleming, as opposed to yourself, sir, ever done a depreciation study on a single class of assets before, to your knowledge?

A. MR. KENNEDY: I don't think they did. In preparation for this proceeding, I in fact asked the [analysts] in our firm during one of our staff calls. They have -- not as a specific depreciation study. They have, as I have done in a number of cases, been involved in applying as part of a capital program that's introduced new types of assets and developed a depreciation rate for a new class of assets as part of a new capital program. That's really not uncommon.⁶³²

585. Mr. Kennedy also acknowledged that a depreciation study involving a single asset account can be considered unusual.⁶³³

586. When asked to demonstrate that there was no effect on depreciation expense in other accounts arising from a depreciation report on a single asset account that implemented accelerated depreciation, Mr. Kennedy and EPCOR indicated that there would be no material effect on depreciation expense in any other asset account as a result of implementing the AMI program and the associated proposed accelerated retirement of EPCOR's conventional metering assets. Specifically, Mr. Kennedy stated that while "it was expected and normal practice of many electric distribution utilities that implement AMI programs to install additional software or modify communication systems, my experience has shown that the impact on the average life of these accounts resulting from the AMI program is non-existent or immaterial."⁶³⁴ EPCOR confirmed to Mr. Kennedy that no other accounts would incur any material amount of asset retirements.⁶³⁵

587. Regarding Mr. Shymanski's objection that EPCOR did not heed the Commission's recommendation in paragraph 606 of Decision 3100-D01-2015 to consider "having the service lives the same for all of the vintages of assets within an asset class," EPCOR stated it did not

⁶³⁰ Exhibit 20407-X0232, UCA argument, paragraph 51.

⁶³¹ Bulletin 2006-25, Announcing the Approval in Principle of the Form and Content of a Uniform System of Accounts and Minimum Filing Requirements for Alberta Electric Utilities, July 12, 2006.

⁶³² Transcript, Volume 4, page 710, lines 7-23 (Mr. Kennedy) as corrected in Exhibit 20407-X0230.

⁶³³ Transcript, Volume 4, page 709, lines 7-20 (Mr. Kennedy).

⁶³⁴ Exhibit 20407-X0174, rebuttal evidence of Mr. Kennedy for EPCOR, page 3.

⁶³⁵ Exhibit 20407-X0174, rebuttal evidence of Mr. Kennedy for EPCOR, page 7.

comment on this matter because the current application involved a depreciation review for only one asset class. EPCOR indicated that to the extent this issue remains relevant for the parameters of the next generation PBR plan, including any evolution of the capital tracker mechanism, EPCOR will address this recommendation at the time of the rebasing at the end of the current PBR term.⁶³⁶

588. In its argument, the UCA advanced its view that the accelerated depreciation costs associated with the early retirement of the conventional metering assets do not satisfy the requirements of Criterion 1 and Criterion 2 for capital tracker treatment.⁶³⁷ EPCOR responded that capital tracker criteria apply to capital projects, whereas depreciation expense related to the conventional meters is a capital cost associated with the Customer Revenue Metering Growth and Life Cycle Replacement capital project. It is a capital related cost arising from a capital project that satisfies the Commission's criteria for capital tracker treatment.⁶³⁸

589. In his evidence for the CCA, Mr. Thygesen indicated that paragraph 688 of Decision 2012-237 appears to allow depreciation changes only if they qualify for Z factor treatment.

688. Fortis, ATCO Electric, ATCO Gas and AltaGas all requested Y factors related to depreciation changes. The companies requesting these Y factors indicated that depreciation studies do not occur on an annual basis. However, even when new depreciation studies are performed, it is not certain that significant changes in depreciation rates will result. If a substantial change does occur, the change may be a result of changes in management assumptions, which would cause the change to not be eligible for flow-through treatment in the form of either a Y factor or Z factor. However, if the change results from some circumstance that is outside of management control, the change may be eligible for Z factor treatment. Due to the unforeseeable nature of depreciation changes, the infrequent occurrence, and the uncertainty as to whether the changes would be eligible for flow-through treatment, depreciation changes will not be treated as a Y factor. [footnotes omitted]

590. Mr. Thygesen expressed his view that the Commission's finding in paragraph 688, indicating that changes to depreciation rates that arise as the result of management assumptions, cannot be passed through to customers unless the changes qualify for Z factor treatment, apply equally to depreciation rate changes requested in connection with a K factor. Mr. Thygesen provided the following rationale in support of his view:

The K, Y and Z factors developed by the Regulator may have similar characteristics. The common variable throughout K, Y and Z factors is that the actual costs incurred are recovered. This distinguishes them from costs incurred under the I-X portion of the formula where revenues and costs are decoupled. In other words, under [I-X] a fixed revenue stream is recovered, regardless of the costs incurred. Since a K is like a Y and arguably somewhat like a Z in many respects; if the change to the depreciation study was initiated by management the change should not be allowed. Without getting too granular, the rationale behind the Commission's finding is that if management initiated depreciation changes were allowed, then revenue can simply be changed by modifying the accounting policies and assumptions upon which going-in rates are based. Therefore,

⁶³⁶ Transcript, Volume 3, pages 513-514 (Mr. Baraniecki).

⁶³⁷ Exhibit 20407-X0232, UCA argument, paragraph 41.

⁶³⁸ Exhibit 20407-X0237, EPCOR reply argument, paragraph 24.

the additional depreciation expense resulting from the depreciation study should be disallowed.⁶³⁹

591. The CCA, in its argument, maintained that the evidence on the record filed by EPCOR is clear that it is a management decision to change the depreciation rate as a result of proceeding with the AMI project and, therefore, it did not qualify as a Z factor.⁶⁴⁰

592. Mr. Thygesen, on behalf of the CCA, submitted that the “revised depreciation resulting from the depreciation study is clearly equivalent (in terms of financial impact) to a change in accounting policy. Such changes are generally not allowed under PBR, without approval by the regulator as these changes to the policies and practises which existed under the going-in rates will likely distort PBR outcomes without other adjustments.”⁶⁴¹ Mr. Thygesen observed that because EPCOR’s going-in rates were reflective of the approved (i.e., non-accelerated) depreciation amounts, “by changing the depreciation, you are changing the going-in rates.”⁶⁴²

593. EPCOR responded to the CCA stating that paragraph 688 of Decision 2012-237, “does not say anything about K factors and, further, it in no way precludes the approval of EDTI’s Customer Revenue Metering Growth & Life Cycle Replacement Tracker as applied-for.”⁶⁴³ EPCOR pointed out that depreciation expense is a legitimate capital-related cost that is reflected in the capital tracker models. In this regard, EPCOR explained that the Commission’s approved approach to calculating the capital funding shortfall associated with each proposed capital tracker project ensures that there will be no double recovery of any costs (i.e., costs recovered under I-X and K factor amounts), including depreciation expense. Therefore, EPCOR submitted that the inclusion of accelerated depreciation in the revenue requirement calculation for the Customer Revenue Metering – Growth & Life Cycle Replacements project will not result in the double recovery of any project costs and cannot be characterized as a change to going-in rates, as maintained by the CCA.⁶⁴⁴

594. Finally, both the UCA and the CCA questioned whether EPCOR’s proposed depreciation change to accelerate the recovery of the remaining investment in conventional meters is consistent with the Commission’s determinations in Decision 3100-D01-2105 that the early retirement of the existing conventional meters would constitute “sudden and complete obsolescence” as contemplated in the UAD Decision 2013-417 and, therefore, the net book value of the undepreciated meters would accrue to EPCOR’s shareholder rather than customers.⁶⁴⁵

595. During the hearing, in an exchange with Commission counsel, it was established that Mr. Kennedy was first approached by EPCOR to conduct a depreciation study in mid-March 2015.⁶⁴⁶ The contract between Mr. Kennedy and EPCOR was signed on April 1, 2015; however, the contract stipulated that a preliminary draft of the depreciation report will be provided to

⁶³⁹ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 63 as corrected in Exhibit 20407-X0222.

⁶⁴⁰ Exhibit 20407-X0234, CCA argument, paragraphs 135-140.

⁶⁴¹ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 65.

⁶⁴² Transcript, Volume 5, page 902, lines 2-6 (Mr. Thygesen).

⁶⁴³ Exhibit 20407-X0237, EPCOR reply argument, paragraph 27.

⁶⁴⁴ Exhibit 20407-X0237, EPCOR reply argument, paragraph 28.

⁶⁴⁵ Decision 3100-D01-2015, paragraph 691.

⁶⁴⁶ Transcript, Volume 4, page 637, lines 7-17 (Mr. Kennedy).

EPCOR by March 23, 2015.⁶⁴⁷ Mr. Kennedy explained that “there was a bit of urgency to undertake this project. [...] So we undertook the work while the contract was going back and forth, if you will, between the two companies for signing.”⁶⁴⁸ The contract also stipulated that the finalized report will be provided by April 6, 2015. During the hearing, Mr. Kennedy clarified that he provided to EPCOR the first draft on April 17, 2015 and the final draft on April 29, 2015, “which is a little bit different than the dates we had in the contractual document.”⁶⁴⁹

596. In an exchange with Commission counsel, Mr. Reimer indicated that the final decision to proceed with the AMI project was made at the EPCOR board of directors meeting, prior to receiving Mr. Kennedy’s draft report:

Q. MR. MCNULTY: Thank you, sir. Just following up on that, Mr. Reimer, you indicated that the decision to go ahead with AMI was undertaken in April of 2015; is that right, sir?

A. MR. REIMER: That is correct.

Q. Was that before or after receiving either the -- well, after the first draft of the depreciation study?

A. MR. REIMER: I think the final decision was at a board of directors' meeting on April 3rd. The decision had been made prior to that, but it went up to the elevated heights within the company and so Mr. Kennedy's evidence -- our report wasn't part of that at all.⁶⁵⁰

597. Mr. Reimer further elaborated on the timing of the decision to proceed with the AMI project as follows:

Q. And when did implementation of the AMI project actually commence? When did you actually start replacing or preparing to replace meters?

A. MR. REIMER: We actually had been working on the project in parallel since I guess - as of last year going through the RFP process. We continued on that up until the decision point was received from the Commission. And in parallel of that, we undertook an analysis of the Commission's findings. And, then, as we came to the conclusion that we set forward here, we just continued on with the project. We didn't really halt it. We did hold back a couple, obviously, financial decisions. We didn't sign any contracts until we had made that determination and got approval from our board. But we did proceed with discussions and some work on the project.⁶⁵¹

598. Mr. Baraniecki clarified that the final decision to proceed with the AMI meters was made at the EPCOR board of directors meeting on April 7, 2015.⁶⁵² Mr. Baraniecki also indicated that EPCOR’s decision to proceed with the AMI project was unrelated to the recommendations in Mr. Kennedy’s report to depreciate the conventional meters at a faster rate than what was approved in the prior depreciation study, as noted in the following exchange with Commission counsel:

⁶⁴⁷ Exhibit 20407-X0203, Mr. Kennedy’s retainer, page 2.

⁶⁴⁸ Transcript, Volume 4, page 638, lines 4-13 (Mr. Kennedy).

⁶⁴⁹ Transcript, Volume 4, page 646, lines 1-7 (Mr. Kennedy).

⁶⁵⁰ Transcript, Volume 4, page 646, lines 8-20 (Mr. Reimer).

⁶⁵¹ Transcript, Volume 4, page 647, line 18 to page 648, line 8 (Mr. Reimer).

⁶⁵² Transcript, Volume 4, page 696, lines 23-25 (Mr. Baraniecki).

Q. Was a decision made to proceed with AMI -- was it partially based on discussions you had with Mr. Kennedy in terms of his ability to file -- or to prepare a depreciation study which would have an accelerated term of three years?

A. MR. BARANIECKI: No. It's explained again in the response to CCA 18,⁶⁵³ but we made our decision based on those four bullet points; namely, the substantial benefits to customers in the long term, the project, being one of the primary ones. But Mr. Kennedy's report and recommendations and other report were unrelated to the decision.

Q. So the decision was unrelated to whether or not the conventional meters could be depreciated at a faster rate than what was in the prior depreciation study; is that right?

A. MR. BARANIECKI: That's correct.

Q. Tell me if I'm incorrect, but that appears to be saying the company has decided to proceed with that, with AMI project, whether or not the accelerated depreciation of the meters was approved by the Commission or not?

A. MR. BARANIECKI: That is correct.⁶⁵⁴

599. In response to a Commission IR, Mr. Shymanski stated that it is not the case that the Life Span approach with a life span date of December 31, 2017 could have been determined independently of the Commission's finding in Decision 3100-D01-2015 that the early retirement of the existing conventional meters would constitute "sudden and complete obsolescence" as contemplated in the UAD Decision 2013-417. Accordingly, "EDTI waited for the Commission decision before changing their minds and requesting Mr. Kennedy's analysis."⁶⁵⁵ Accordingly, Mr. Shymanski expressed concern that EPCOR's accelerated depreciation proposal "may operate as a collateral attack on the Commission's finding in Decision 3100-D01-2015."⁶⁵⁶

600. In its argument, the UCA shared Mr. Shymanski's concerns and submitted that the timing of EPCOR's 2015 depreciation study was "suspect" because it was filed subsequent to the findings of the Commission in Decision 3100-D01-2015.⁶⁵⁷ The UCA argued it was inappropriate for EPCOR "to seek to obtain a certain treatment of its undepreciated costs for conventional meters (preferential to its shareholders and detrimental to customers) by strategically delaying its decision to retire those assets."⁶⁵⁸

601. Additionally, the UCA argued that the inclusion of the accelerated depreciation costs of EPCOR's conventional metering assets in a capital tracker project violates the regulatory principle established by the courts and as reflected in the UAD decision, that customers should not be required to pay for assets that are not used to provide utility service. The UCA submitted that allowing EPCOR "to use the annual Capital Tracker mechanism to side step the

⁶⁵³ [Sic] Exhibit 20407-X0154, EDTI-CCA-2015JUN26-017.

⁶⁵⁴ Transcript, Volume 4, page 646, line 21 to page 647, line 17 (Mr. Baraniecki).

⁶⁵⁵ Exhibit 20407-X0171, UCA-AUC-2015JUL30-005(b).

⁶⁵⁶ Exhibit 20407-X0171, UCA-AUC-2015JUL30-005(a).

⁶⁵⁷ Exhibit 20407-X0232, UCA argument, paragraph 52.

⁶⁵⁸ Exhibit 20407-X0232, UCA argument, paragraph 53.

determinations made by the Commission in Decision 3100-D01-2015, ... would serve to undermine the principles of PBR.”⁶⁵⁹

602. The CCA raised a similar issue. Mr. Thygesen stated that “the depreciation study is clearly a one-off study in response to the AMI project and in response to the last Decision which did not rule on AMI as a capital tracker.”⁶⁶⁰ Mr. Thygesen expressed his view that EPCOR’s accelerated depreciation proposal attempts to “avoid the stranded asset provisions of the UAD decision.”⁶⁶¹ In its argument, the CCA supported this conclusion.⁶⁶²

603. In its argument, EPCOR submitted that denying recovery of the investment in these circumstances would continue to create perverse incentives for utilities in Alberta, where they would be motivated “to avoid identifying and proposing such cost saving initiatives for fear of being denied the opportunity to recover undepreciated capital investment and suffering financial loss.”⁶⁶³ In EPCOR’s view, such perverse incentives are contrary to the objectives of PBR.

604. EPCOR also referenced the Alberta Court of Appeal decision in *FortisAlberta Inc v. Alberta (Utilities Commission)*, 2015 ABCA 295, which dismissed an appeal of the UAD decision. EPCOR referred specifically to paragraph 168 wherein the Court noted that the Commission had been careful not to fetter its discretion allowing it “to adjust for depreciation and amortization expenses of assets removed from service for unanticipated causes through its amortization of reserve differences process.” EPCOR submitted that this provision provided the Commission with “the discretion to refrain from strictly applying the principles of Stores Block where the Commission determines that the specific circumstances before it warrant a different result.”⁶⁶⁴

605. EPCOR also referred to the recent Supreme Court of Canada decision in *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 that referenced “the “prudent investment test” as a tool to soften the potentially harsh effects of the “used and useful test.”⁶⁶⁵

Commission findings

606. While the Commission has evaluated the arguments of the CCA, the UCA and EPCOR in considering EPCOR’s proposal to include the accelerated depreciation amounts for conventional meters in the K factor calculation associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project, it considers that the findings in respect of a single issue, whether the change in depreciation rates is permitted in customer rates under the provisions of the PBR plan approved for the company in Decision 2012-237, will be determinative of the matter.

607. At paragraph 688 of Decision 2012-237, the Commission denied Y factor treatment for changes related to depreciation and determined that any depreciation changes under the existing

⁶⁵⁹ Exhibit 20407-X0232, UCA argument, paragraph 54.

⁶⁶⁰ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 74.

⁶⁶¹ Exhibit 20407-X0167, CCA-AUC-2015JUL30-003(e).

⁶⁶² Exhibit 20407-X0234, CCA argument, paragraph 146.

⁶⁶³ Exhibit 20407-X0233, EPCOR argument, paragraph 292.

⁶⁶⁴ Exhibit 20407-X0233, EPCOR argument, paragraphs 298-300.

⁶⁶⁵ Exhibit 20407-X0233, EPCOR argument, paragraph 301.

PBR framework may be reflected in rates only if they are eligible for Z factor treatment. EPCOR argued that the referenced paragraph does not address K factors specifically, and “in no way precludes the approval of EDTI’s Customer Revenue Metering Growth & Life Cycle Replacement Tracker as applied for.”⁶⁶⁶ The Commission disagrees. Paragraph 688 of Decision 2012-237 is intended to limit the circumstances in which a company may file a depreciation study affecting customer rates within the PBR term to only the events beyond the control of the company, that require a rate adjustment through the Z factor mechanism. A Z factor is not available for changes to rates resulting from a depreciation study where the depreciation changes result from changes in management assumptions or company decisions. Accordingly, paragraph 688 does apply to the capital tracker mechanism in general, and to EPCOR’s request for accelerated depreciation in this proceeding.

608. The Commission provided two reasons for its determinations in paragraph 688 of Decision 2012-237. The first reason related to the reduction in administrative burden under PBR and the associated increase in regulatory efficiency, given that “depreciation studies do not occur on an annual basis...[and] ...even when new depreciation studies are performed, it is not certain that significant changes in depreciation rates will result.”⁶⁶⁷ In the Commission’s view, permitting a company to file a depreciation study for all or some of its asset accounts as part of a capital tracker application would be inconsistent with the third PBR principle⁶⁶⁸ established by the Commission, namely a PBR plan should be easy to understand, implement and administer and should reduce regulatory burden. The introduction of depreciation studies into PBR proceedings, except in the circumstances that might qualify for a Z factor adjustment, does not comport with the objective of PBR to reduce regulatory burden and to allow companies to operate within an established revenue framework during the PBR period. PBR is intended to create productivity incentives, but not incentives to re-examine accounting policies and depreciation parameters as part of a capital tracker application.

609. The Commission recognizes that a change in rates under the PBR regime would require the Commission to consider the implications of proposed changes to depreciation rates, including the effect of such changes on the company’s going-in rates, revenues obtained under I-X, as well as revenues obtained through other components of the PBR formula, including capital trackers, and the resulting effect on the company’s ROE, among others.

610. The second reason set out in paragraph 688 of Decision 2012-237, for disallowing depreciation changes to be reflected in customer rates other than through a Z factor, is that the proposed change in depreciation rates “may be a result of changes in management assumptions.”⁶⁶⁹ The Commission recognizes that depreciation changes that are a result of changes in management assumptions may be adopted only to generate more return to the company. Mr. Baraniecki acknowledged that this may be a concern in the following exchange with Commission counsel.

... So in your view, sir, what incentive was the Commission trying to guard against by requiring -- by allowing changes in depreciation rates only in the event they result out of an event that's outside the control of the management of the company?

⁶⁶⁶ Exhibit 20407-X0237, EPCOR reply argument, paragraph 27.

⁶⁶⁷ Decision 2012-237, paragraph 688.

⁶⁶⁸ Decision 2012-237, paragraph 28.

⁶⁶⁹ Decision 2012-237, paragraph 688.

A. MR. BARANIECKI: Again, putting aside K factors in that conversation and my answer here, I would presume there is the ability for the utility to significantly change their depreciation rates, or there could be if it wasn't a Y factor; and I would think -- I guess, let's say, lengthening the asset service lives or average service lives, and then incurring less capital cost, and then capture more revenues or more [net income]. I suppose that's a way -- sort of a thing that the Commission was trying to guard against by not having it as part of a Y factor or a Z factor unless it's outside the management control.⁶⁷⁰

611. In this regard, the Commission accepts EPCOR's explanation that under the Commission-approved methodology, the accounting test as part of Criterion 1 ensures that there is no double recovery of any depreciation costs between the costs recovered under the I-X mechanism and costs recovered through a K factor. Indeed, in its argument, the UCA noted that Mr. Shymanski, who questioned whether a proposed accelerated depreciation of conventional meters would result in a double-counting, "has reviewed Exhibits 20407-X0123, X0124 and X0125 and can confirm that the issue of double counting raised in the information response is no longer a concern of Mr. Shymanski."⁶⁷¹

612. While the Commission agrees that double counting of the same depreciation expense will not occur because of the accounting test, the filing of depreciation studies in a capital tracker application resulting from a change in management assumptions, can give rise to other concerns relating to possible intentional or unintentional manipulation of revenues and profits through changes to depreciation rates. One such concern is that changes to depreciation rates may result in certain projects qualifying for capital tracker treatment because of a higher revenue requirement, where they would not otherwise qualify in the absence of such changes. Similarly, a company may choose not to file a depreciation study that would result in projects no longer qualifying for capital tracker treatment, where they would qualify in the absence of such changes.

613. The effects of a change in management assumptions on depreciation rates is illustrated in the following exchange between Mr. Kennedy and Commission counsel:

Q. So in this circumstance, is it true that, in effect, the company has determined the average service life of its assets, of the conventional meters which then translates to depreciation expense which you've calculated for them?

A. MR. KENNEDY: I'm going to answer your question, sir, by saying the company determined the retirement plan for those assets. Given its very short-term nature, it ultimately was, by far, the driving force. Like, 99 percent was probably the driving force of the depreciation expense in this circumstance.

...

So yes, the company determined the pattern in which these assets are going to retire, which, in this specific circumstance, resulted in, in essence, the decision of the three-year life estimate on these. But I think my input to it was the manner in which we could

⁶⁷⁰ Transcript, Volume 4, page 742, lines 1-17 (Mr. Baraniecki) as corrected in Exhibit 20407-X0230.

⁶⁷¹ Exhibit 20407-X0232, UCA argument, paragraph 55.

execute that through depreciation expense in a fair basis to recognize the service life of the assets.

Q. So if EPCOR changed its mind tomorrow and extended the plan, instead of a three-year plan, to a five-year plan with the existing conventional meters being replaced over five years, would you have to change your depreciation study?

A. MR. KENNEDY: I would suggest it would be something that I would recommend them to do, yes.

Q. To go to five years?

A. MR. KENNEDY: Yes...⁶⁷²

614. The exchange continued as follows:

Q. So the expected service life and your recommendations as to average service life and the approach that you would use in determining that and, therefore, the depreciation expense that would result and then, therefore, the resulting revenue requirement associated with the project could change at any time at the direction of the company's decision on how they implement the plan; is that right?

A. MR. KENNEDY: Yes, sir. And I want to be clear. The company came to me and said, Mr. Kennedy, we are now implementing this over five years and here's the pattern of [retirements], I would suggest, sure, we should update that schedule. How that mechanism would work within the realm of the revenue requirement under a PBR regime is something that I would not have any input on. That's not my realm of expertise. My expertise would be to give them the appropriate match of the assets in service and the depreciation expense to consider as service value.⁶⁷³

615. Both EPCOR⁶⁷⁴ and Gannett Fleming⁶⁷⁵ indicated that the proposed changes to the depreciation rates for the conventional meters are reflective of the company's decision to proceed with the AMI project and the resulting reduction in service life of EPCOR's conventional meters. In Section 6.4.2.5 of this decision, the Commission determines that given the company's statements about the motivation to proceed with the AMI project, and what its actions would have been in the absence of a change to Measurement Canada's meter testing requirements, the implementation of the AMI project cannot be considered attributable to an event outside management's control. Therefore, the project does not satisfy the first criterion for both Y factor and Z factor treatment, as set out in Decision 2012-237.⁶⁷⁶ Accordingly, the Commission finds that the proposed change in depreciation rates for the existing meters does not qualify for Z factor treatment.

⁶⁷² Transcript, Volume 4, page 667, line 12 to page 668, line 21 (Mr. Kennedy).

⁶⁷³ Transcript, Volume 4, page 669, line 19 to page 670, line 12 (Mr. Kennedy) as corrected in Exhibit 20407-X0230.

⁶⁷⁴ Exhibit 20407-X0130.02, revised application, paragraph 507.

⁶⁷⁵ Exhibit 20407-X0004, Appendix D, 2015 Depreciation Study, page 5.

⁶⁷⁶ Decision 2012-237, paragraphs 524-525 (Z factor criteria) and 631-632 (Y factor criteria).

616. For all of the above reasons, the Commission finds that determinations in paragraph 688 of Decision 2012-237 also apply to K factors. Accordingly, given that EPCOR's accelerated depreciation proposal is contrary to the Commission's determinations at paragraph 688 of Decision 2012-237, EPCOR's application to change existing depreciation rates on conventional meters and to recover the accelerated depreciation through the K factor calculation associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project is denied. In the compliance filing to this decision, EPCOR is directed to remove the accelerated depreciation amounts from the K factor calculation and base its revenue requirement calculation associated with this project on the amounts reflective of the depreciation rates approved in Decision 2012-272.

617. The treatment of any remaining undepreciated capital investment in EPCOR's non-AMI meter assets and related UAD implications, will be considered at rebasing of EPCOR's PBR plan or in EPCOR's next general tariff application. The Commission considers the following findings of fact based on the evidence in this proceeding relevant to any future consideration of the undepreciated capital costs of the conventional meters. The evidence demonstrates that the decision to proceed with the AMI project was made by EPCOR management, subject to board of directors' authorization to proceed with third-party contractual commitments, prior to and irrespective of, the decision to retain Gannett Fleming in mid-March 2015. Further, EPCOR's board of directors' approval to proceed with financial commitments and implement the project and retire the conventional meters was received on April 7, 2015, prior to delivery of the first draft of the depreciation study on April 17, 2015. As noted by an EPCOR witness:

...we made our decision based on those four bullet points; namely, the substantial benefits to customers in the long term, the project, being one of the primary ones. But Mr. Kennedy's report and recommendations and other report were unrelated to the decision.⁶⁷⁷

618. The events that triggered the decision to remove from service the conventional meters by replacing them with AMI meters occurred prior to the company providing Gannett Fleming instructions to prepare a new depreciation study and prior to the finalization of the depreciation study, which contemplates for the first time the retirement of the conventional meters within a three year period. Further, the company decided to remove the conventional meters from service over a three year period and this was then determined to be the applicable life span by Gannett Fleming in its application of the Life Span approach to depreciation, which resulted in depreciation rates for conventional meters in its 2015 depreciation study.

6.4.2 AMI project

619. This multi-year project involves the installation of AMI meters and networking infrastructure that will fully automate EPCOR's revenue meter reading function. The AMI technology (including the installation of AMI meters, also known as "smart meters") will replace currently used manual processes for reading and energizing or de-energizing meters, and enable more efficient access to end-user information such as usage, voltage, tamper detection and service interruption and restoration indications. It will also remotely manage functions such as service connections, service disconnections, load limiting and firmware upgrades. EPCOR

⁶⁷⁷ Transcript, Volume 4, page 647, lines 2-7 (Mr. Baraniecki).

provided a business case and an engineering study for the AMI project in Appendix A-19 of the application.

620. EPCOR is implementing the AMI project from 2014 to 2017 in two phases. Phase 1 consists of constructing and testing the AMI network infrastructure, including collectors and all computer hardware and software, and installing approximately 10,000 AMI “smart” meters to test the system. Following successful deployment of the AMI infrastructure, Phase 2 will begin. Phase 2 will be implemented in 2016 and 2017 and will involve replacing nearly all of EPCOR’s approximately 365,000 existing meters (composed of a mix of electro-mechanical meters and electronic AMR meters) with AMI meters.⁶⁷⁸ As a result of implementation of the project, significant cost savings will result, including the elimination of meter reader positions. Further details of the project schedule are provided in Section 6.4.2.3.

621. EPCOR is seeking approval for capital tracker treatment of the AMI project on a forecast basis for 2016 and 2017. There were no capital additions for this project in 2014. EPCOR forecast capital additions for the AMI project to be \$11.89 million in 2015, \$32.74 million in 2016 and \$26.07 million in 2017. As shown in Table 2 from Section 4 of this decision, the K factor amount associated with the AMI project is \$2.12 million in 2016 and \$5.89 million in 2017. As previously discussed in Section 6.4.1.2 of this decision, EPCOR also applied for approval to accelerate depreciation of existing electro-mechanical and AMR meters and to recover the remaining net book value over a three-year period, given that these meters will be replaced with AMI meters over a three-year period.

622. A number of issues were raised in relation to the AMI project in this proceeding. The first two issues relate to the need for the AMI project and consideration of project scope, level, timing and the resulting 2016 and 2017 forecast expenditures associated with this project. These two issues are addressed in Section 6.4.2.1 and Section 6.4.2.3 of this decision, respectively. Section 6.4.2.2 deals with EPCOR’s analysis that the AMI project represents the least cost alternative for performing the customer revenue metering function over a 20-year period. Section 6.4.2.4 addresses other considerations brought forward by EPCOR in support of the AMI project. The assessment of the above matters contributes to the Commission’s project assessment under capital tracker Criterion 1 for the AMI project. The Commission’s conclusions on whether the AMI project meets the project assessment requirements under Criterion 1 are presented in Section 6.4.2.6.

623. Additional issues raised by interveners involved consideration of whether the AMI project qualifies for Y factor or Z factor treatment. These matters are discussed in Section 6.4.2.5. Finally, the UCA and the CCA also argued that the AMI project does not meet the requirements of capital tracker Criterion 2. This matter is addressed in Section 8 of this decision.

6.4.2.1 Need for the project

624. EPCOR first applied for approval of a similar AMI project as part of its 2010-2011 GTA. In Decision 2010-505, the Commission did not approve capital expenditures for EPCOR’s AMI

⁶⁷⁸ Exhibit 20407-X0082, Appendix A-19, paragraphs 21-22.

project for two reasons: the business case for the project was not well founded⁶⁷⁹ and the absence of a provincial smart grid policy.⁶⁸⁰

625. In its 2014-2015 capital tracker application, Proceeding 3100, EPCOR brought forward the AMI project for approval as a capital tracker. In Decision 3100-D01-2015, the Commission found that EPCOR's AMI capital tracker proposal did not suffer from the same drawbacks as the earlier AMI proposal, which was rejected by the Commission in Decision 2010-505. Specifically, the Commission indicated that EPCOR had sufficiently addressed the deficiencies identified by the Commission in Decision 2010-505 and presented an improved cost-benefit analysis for the project. Regarding the clarity of a provincial smart grid policy, the Commission noted that the Alberta Department of Energy released the AUC Smart Grid Inquiry Report⁶⁸¹ on June 1, 2011. The Commission made the following determinations:

661. The Commission has reviewed EDTI's business case for the AMI project, including the two NPV analyses, and finds EDTI's cost-benefit analysis for the AMI project to be reasonable. Based on the evidence in the present proceedings, the Commission finds that, over the 20-year period presented in the business case, the AMI project represents the least cost alternative for performing the customer revenue metering function for EDTI, at this time.⁶⁸²

626. Decision 3100-D01-2015, however, did not rule on whether the AMI project qualified for capital tracker treatment as the issue was rendered moot following the Commission's determinations that the early retirement of existing electro-mechanical and AMR meters by AMI meters would constitute a "sudden and complete obsolescence" of these meters, as contemplated in the UAD decision, Decision 2013-417, and EPCOR's position that it would not implement the AMI project if its shareholders would be responsible for the remaining net book value of the existing meters when they were retired.⁶⁸³

627. In the present application, EPCOR re-applied for capital tracker treatment of the AMI project on a forecast basis for 2016 and 2017. EPCOR indicated that it has decided to proceed with the AMI project in advance of receiving approval for capital tracker treatment for the project in this proceeding, and regardless of the Commission's determinations respecting the treatment of the remaining net book value of the existing meters.⁶⁸⁴ Furthermore, during the oral hearing, Mr. Baraniecki for EPCOR indicated in an exchange with Commission counsel, that the company will most likely proceed with the AMI project even if capital tracker treatment is not afforded to the project:

Q. Is that also the case in the event that the Commission does not approve the AMI capital tracker?

A. MR. BARANIECKI: At this point I don't -- I think we're contractually bound to the contractor to put in the AMI meters.

⁶⁷⁹ Decision 2010-505, paragraphs 343-353.

⁶⁸⁰ Decision 2010-505, paragraphs 355-359.

⁶⁸¹ Alberta Smart Grid Inquiry, Proceeding 598, January 31, 2011.

⁶⁸² Decision 3100-D01-2015, paragraph 661.

⁶⁸³ Decision 3100-D01-2015, paragraph 705.

⁶⁸⁴ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-017(a).

Mr. Reimer informed me that a couple weeks ago we actually ran out of conventional meters so we're putting in AMI meters anyways. And if in the event that the Commission found that this project should not be a K factor, then we'll have to figure out what we do from there. But I think we have to continue on with the project and we would obviously look at all the avenues we have available to us to ensure that we have -- or to attempt to get recovery of this project as a K factor or other means.⁶⁸⁵

628. EPCOR explained it decided to do so because the project is in the best interests of its customers from a cost perspective since it represents the least cost alternative over the long term for responding to the changes in Measurement Canada meter testing, verification and replacement requirements.⁶⁸⁶ EPCOR further indicated it has made no project schedule changes and has not incurred any project delays since the time of the 2014-2015 capital tracker application.⁶⁸⁷

629. To support the need for this project, EPCOR indicated that as the owner of an electric distribution system and in compliance with Measurement Canada regulations, EPCOR must provide each metered site with a meter. EPCOR must also provide a replacement meter if an existing meter stops functioning or requires replacement under Measurement Canada regulations. The federal *Electricity and Gas Inspection Act* requires Measurement Canada-approved meters to be installed for customer billing. The act also mandates that meters be tested and maintained in accordance with the regulations.⁶⁸⁸

630. EPCOR stated that the AMI project is a process improvement project that is required to provide utility service at adequate levels and at reasonable cost to its customers. Specifically, EPCOR highlighted that if it does not proceed with this project, it will incur higher operating costs (for example, to read meters) and capital costs (to meet new Measurement Canada specification S-S-06 previously discussed in Section 6.4.1.1 of this decision), all of which would ultimately be borne by customers through higher rates. EPCOR maintained that the cost savings associated with the AMI project are substantial, and will be enjoyed by customers over the service life of the advanced metering infrastructure proposed for this project.

631. In argument, EPCOR elaborated on how the changes to Measurement Canada's testing requirements affected the need and timing for the AMI project as follows:

An important factor for EDTI bringing the AMI Tracker forward is the change in Measurement Canada meter compliance testing requirements that were first announced in 2010 and have now been implemented. As described in detail in Appendix A-16, in the absence of EDTI's proposed AMI project, these new requirements mandated that EDTI test and replace a substantially higher number of existing meters on its system beginning in 2014 and 2015 and carrying forward into future years. By moving forward with the AMI project, EDTI has in the near term been able to obtain dispensation from Measurement Canada to avoid what would have otherwise been a substantial testing and replacement program in 2014 through 2017. In the years after the planned completion of the AMI project in 2017, EDTI will be able to avoid the lion share of the impact of the higher testing and replacement requirements because its meters will be new and, as such,

⁶⁸⁵ Transcript, Volume 4, page 649, line 21 to page 650, line 10 (Mr. Baraniecki).

⁶⁸⁶ Exhibit 20407-X0233, EPCOR argument, paragraph 227.

⁶⁸⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050(b).

⁶⁸⁸ Exhibit 20407-X0082, Appendix A-19, paragraphs 13-14.

will not require any significant compliance testing or replacement for a considerable time period.⁶⁸⁹

632. In the business case for the project, EPCOR also highlighted supply issues associated with the remaining electro-mechanical and AMR meters. EPCOR elaborated on this point by stating:

Finally, AMR technology has been supplanted by AMI technology as a standard metering option for electric meters; this is evidenced by the limited number of vendors offering basic AMR type meters as opposed to the extensive number of vendors offering full function AMI meters. In Canada, EDTI is aware of only two vendors that continue to offer AMR RF electric meter technology compared to more than eight vendors offering one or more standard full function AMI meters.⁶⁹⁰

633. While both Mr. Bell for the UCA and Mr. Thygesen for the CCA, did not dispute that EPCOR should implement the AMI project (as further discussed below), they argued that the AMI project fails to satisfy the requirements of capital tracker Criterion 1. Both interveners referred to the requirements set out at paragraph 594 of Decision 2012-237 that Criterion 1 is “required to ensure that capital tracker projects are of sufficient importance that the company’s ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken” and that “the company must demonstrate that the capital expenditures are required to prevent deterioration in service quality and safety, and that service quality and safety cannot be maintained by continuing with O&M and capital spending at levels that are not substantially different from historical levels.”

634. Mr. Bell asserted that there is no evidence that EPCOR will fail to maintain service quality and safety at current levels without AMI. In his oral testimony, Mr. Bell stated that EPCOR has been able to comply with the meter reading service quality levels mandated under Rule 002⁶⁹¹ using the existing conventional meters.⁶⁹² With reference to parts of his evidence from Proceeding 3100, under which EPCOR’s 2014-2015 capital tracker application was considered, Mr. Bell noted that the AMI project will be improving service quality rather than maintaining or preventing deterioration of service quality.⁶⁹³ The CCA raised similar points in its argument and stated that EPCOR indicated it can provide adequate service levels without the AMI project and that the project will increase service quality levels and is not required to prevent deterioration in service quality and safety.⁶⁹⁴

635. In its argument, the UCA acknowledged that in Decision 3100-D01-2015, the Commission determined that over the 20-year study period, the AMI project represents the least cost alternative for performing the customer revenue metering function for EPCOR. However,

⁶⁸⁹ Exhibit 20407-X0233, EPCOR argument, paragraph 224.

⁶⁹⁰ Exhibit 20407-X0082, Appendix A-19, paragraph 134.

⁶⁹¹ Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

⁶⁹² Transcript, Volume 6, page 998, lines 3-10 (Mr. Bell).

⁶⁹³ Exhibit 20407-X0170, UCA-AUC-2015JUL30-003 (Attachment), Appendix B, Evidence of Russ Bell from Proceeding 3100, black lined version, page 5.

⁶⁹⁴ Exhibit 20407-X0234, CCA argument, paragraphs 115-117.

the UCA submitted that this determination does not mean that the use of conventional meters is not adequate to maintain service quality and safety.⁶⁹⁵ The UCA continued in its reply argument:

Although the evidence indicates that, over the long term, the AMI Project is the lowest cost alternative for providing the customer metering revenue function, that is not the case over the 2015-2017 period. The UCA is of the view that there is insufficient evidence to demonstrate that service quality and safety cannot be maintained during that period by continuing with O&M and capital spending at levels that are not substantially different from historical levels.⁶⁹⁶ [footnote omitted]

636. Both Mr. Bell and Mr. Thygesen indicated that EPCOR should proceed with the AMI project but that it does not qualify for funding under the capital tracker mechanism. During the hearing, Mr. Bell confirmed in an exchange with Commission counsel that he does not object to EPCOR implementing the AMI project without capital tracker treatment:

Q. So are you basically saying, then, that the project is needed and should go ahead but that customers shouldn't pay for it because it doesn't meet capital tracker criteria?

A. MR. BELL: Yes. In my evidence, I've talked about how it does not meet Criterion 1...⁶⁹⁷

637. In his evidence from Proceeding 3100 filed on the record of this proceeding, Mr. Bell also expressed his view that if the project is not approved for capital tracker treatment, this does not mean that EPCOR should not proceed with the AMI project. This is because:

... utility management is obliged to provide safe and reliable service at the lowest cost possible. It is incumbent for utility management to select the least cost alternative. As such, if EDTI chooses a higher cost alternative, it should be at risk for a finding of imprudent action.⁶⁹⁸

638. A similar answer was given to Commission counsel by Mr. Thygesen for the CCA:

Q. You have no objection to the need for the project or the timing or the scope or the costs of the project, but you are proposing an alternative recovery mechanism for the cost of the AMI meters; is that right?

A. Yes. I guess I would just modify, when you say "alternative," I would propose just the recovery mechanism that was espoused during testimony in the last proceeding, which was a Y -- a Y factor.⁶⁹⁹

639. The CCA, in its argument, submitted that, as "an economically rational actor," EPCOR has little choice but to implement the AMI project as a least cost solution to addressing the change in Measurement Canada standards:

EDTI agree AMI is the lowest cost option to meet the revised standards. Thus, whether AMI is legally required is irrelevant. It is the lowest cost solution to meet Measurement

⁶⁹⁵ Exhibit 20407-X0232, UCA argument, paragraph 12.

⁶⁹⁶ Exhibit 20407-X0236, UCA reply argument, paragraph 17(d).

⁶⁹⁷ Transcript, Volume 6, page 997, lines 16-20 (Mr. Bell).

⁶⁹⁸ Exhibit 20407-X0170, UCA-AUC-2015JUL30-003 (Attachment), Appendix B, Evidence of Russ Bell from Proceeding 3100, black lined version, page 13.

⁶⁹⁹ Transcript, Volume 5, page 875, lines 12-22 (Mr. Thygesen).

Canada's requirement. To argue that an economically rational actor such as EDTI would implement something other than AMI is a non sequitur. Further, a solution that involved higher costs would and should be ruled imprudent. Accordingly, although EDTI is not legally required to implement AMI, the evidence and prudence indicates that it is the only solution to the exogenous change in requirements.⁷⁰⁰

640. The CCA submitted that the fact the AMI project would not qualify for capital tracker treatment "should have no bearing on the issue. EDTI could proceed with the project under I-X and reap the benefits over the long term. That is the nature of many long term investments."⁷⁰¹

641. In response to the concerns expressed by interveners, EPCOR stated:

The issue raised by EDTI's proposed AMI Capital Tracker is centrally the cost at which EDTI will continue to maintain current service levels. As explained in detail in the AMI Business Case, EDTI can continue to provide metering service at current service levels without the AMI project, but the costs associated with that alternative will be far higher for customers over the long term.⁷⁰²

642. Mr. Bell referenced another requirement set out in paragraph 594 of Decision 2012-237 that the company is "required to demonstrate that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program." In this regard, Mr. Bell stated that the AMI project could have been undertaken in the past, as evidenced by the fact that both ATCO Gas and FortisAlberta have implemented AMR programs in the years leading up to the implementation of PBR.⁷⁰³

643. In reply, EPCOR pointed out that it did apply for this project as part of its 2010-2011 GTA, but the project was denied in the Commission's Decision 2010-505 because, among other reasons, the regulatory framework for AMI infrastructure had not been finalized at that time. Subsequently, the Alberta Department of Energy released the AUC Smart Grid Inquiry Report on June 1, 2011.⁷⁰⁴ In response, the UCA submitted in its argument that there "is no evidence to indicate that EDTI could not have put forward an AMI Project, which addressed the deficiencies identified in Decision 2010-505, prior to Proceeding 3100."⁷⁰⁵

644. Mr. Bell also indicated that the Commission has already ruled that automated metering is the kind of initiative that PBR is intended to incent. Mr. Bell referenced the Commission's findings in Decision 2012-237 which denied Y factor treatment for AltaGas' AMR program and where the Commission stated that AMR should be undertaken only if it will achieve efficiencies that will outweigh the costs.⁷⁰⁶

⁷⁰⁰ Exhibit 20407-X0234, CCA argument, paragraph 124.

⁷⁰¹ Exhibit 20407-X0238, CCA reply argument, paragraph 66.

⁷⁰² Exhibit 20407-X0233, EPCOR argument, paragraph 255.

⁷⁰³ Exhibit 20407-X0170, evidence of Russ Bell from Proceeding 3100, black lined version, page 5.

⁷⁰⁴ Exhibit 20407-X0173, EPCOR rebuttal evidence, page 14.

⁷⁰⁵ Exhibit 20407-X0232, UCA argument, paragraph 17.

⁷⁰⁶ Decision 2012-237, paragraph 703.

645. EPCOR addressed this concern of Mr. Bell as follows:

EDTI has demonstrated that its AMI project satisfies the criteria for Capital Tracker treatment and should be approved as such. The Commission has not been presented with an application by AltaGas for approval of its AMR project as a Capital Tracker, including supporting information and analyses, business case and engineering study, etc. and, as such, has not had to rule on any such request. AltaGas's approach to its AMR project, whatever that approach may ultimately be and whatever the basis for it may be, is irrelevant to EDTI's Application.⁷⁰⁷

Commission findings

646. EPCOR is required to meter the energy it delivers to customers. The federal *Electricity and Gas Inspection Act* requires that Measurement Canada approve the meters to be installed for customer billing. The act also mandates that meters be tested and maintained in accordance with regulations.

647. In its 2014-2015 capital tracker application, EPCOR indicated that it would not proceed with the AMI project if it was unable to recover the remaining net book value of its existing meters from customers. It has altered its position and made a decision to proceed with the AMI project maintaining the original project schedule set out in the 2014-2015 capital tracker forecast application, without waiting for approval for capital tracker treatment for the project in this proceeding and regardless of the Commission's determinations on the treatment of the remaining net book value of the existing meters.⁷⁰⁸ Furthermore, during the oral hearing, Mr. Baraniecki, for EPCOR, indicated in an exchange with Commission counsel, that the company will most likely proceed with the AMI project even if the capital tracker treatment is not approved for the project as EPCOR is contractually committed for the purchase and installation of the AMI system.⁷⁰⁹ EPCOR carried out an RFP process and entered into fixed-price contracts with the successful bidders for the AMI system purchase (including AMI meters) and meter installation services, as further discussed in Section 6.4.2.3. EPCOR's decision to proceed with the project supports a finding that the project is required and will produce efficiencies and benefits for both the company and customers in the longer term. In Decision 2012-237, the Commission recognized that superior efficiency incentives are created when the company makes capital investment decisions and undertakes investments prior to applying for recovery of costs by way of a capital tracker.⁷¹⁰

648. As set out in Section 6.4.2.2 of this decision, EPCOR considered several alternatives to performing its customer revenue metering function, including the status-quo option of continuing to install AMR meters to replace failed electro-mechanical meters and installing AMR meters at new customer sites. In that section, the Commission finds that based on the evidence in the present proceeding, including the actual negotiated and contracted costs of the AMI system and meter installation services, the AMI project represents the least-cost alternative for performing the customer revenue metering function for EPCOR, over the 20-year period presented in the business case.

⁷⁰⁷ Exhibit 20407-X0233, EPCOR argument, paragraph 244.

⁷⁰⁸ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-017(a).

⁷⁰⁹ Transcript, Volume 4, page 649, line 21 to page 650, line 10 (Mr. Baraniecki).

⁷¹⁰ Decision 2012-237, paragraph 614.

649. Both Mr. Bell⁷¹¹ for the UCA and Mr. Thygesen⁷¹² for the CCA did not object to EPCOR implementing the AMI project at this time, outside of the capital tracker mechanism. In its reply argument, the UCA argued that while the project may represent the lowest cost alternative, that does not mean the project satisfies the requirement of Criterion 1 to establish the need for the project in the time frame proposed. The UCA stated:

Although the evidence indicates that, over the long term, the AMI Project is the lowest cost alternative for providing the customer metering revenue function, that is not the case over the 2015-2017 period. The UCA is of the view that there is insufficient evidence to demonstrate that service quality and safety cannot be maintained during that period by continuing with O&M and capital spending at levels that are not substantially different from historical levels.⁷¹³ [footnote omitted]

650. The argument of the UCA is consistent with its position in Proceeding 3100 that capital tracker Criterion 1 requires evidence demonstrating that in the absence of the capital expenditures associated with a proposed capital tracker project for a given year, deterioration in service quality and safety would result in that year.⁷¹⁴ In Decision 3100-D01-2015, the Commission considered the UCA's interpretation to be too restrictive in the circumstances of most capital replacement and upgrade programs intended to maintain system reliability and safety, for the following reasons:

161. EDTI submitted "the relationship between undertaking the capital program and the impact to service quality is broader than the direct and immediate impact of the program." Capital projects typically involve the construction of long-lived assets, which provide service to customers for many years. As such, requiring the company to demonstrate that, in absence of the capital expenditures for a capital tracker project, deterioration in service quality and safety would result "in that year" does not comport, in most instances, with the long-lived nature of capital assets. The Commission agrees with Mr. Elford that, while there might not be a direct and immediate impact to not completing the project in a specific year, not proceeding with the project will result in a deterioration in reliability over time.

162. Furthermore, a requirement that deterioration in service quality and safety would result "in that year" may prevent the company from selecting the best course of action, including the best timing, to achieve the least cost alternative for a particular capital tracker project. As a result, the company is charged with presenting compelling evidence that the scope, level, and timing of the proposed capital tracker program is prudent and that the forecast costs are reasonable in that year to maintain system reliability and safety to prevent deterioration in system reliability and safety, either in that year or over time.⁷¹⁵ [footnotes omitted]

651. EPCOR explained that the advantage of proceeding with the AMI project at this time is that the company has been able to obtain dispensation from Measurement Canada's new testing requirements, allowing it "to avoid what would have otherwise been a substantial testing and

⁷¹¹ Transcript, Volume 6, page 997, lines 16-20 (Mr. Bell).

⁷¹² Transcript, Volume 5, page 875, lines 12-22 (Mr. Thygesen).

⁷¹³ Exhibit 20407-X0236, UCA reply argument, paragraph 17(d).

⁷¹⁴ Decision 3100-D01-2015, paragraph 155.

⁷¹⁵ Decision 3100-D01-2015, paragraphs 161 and 162.

replacement program in 2014 through 2017.”⁷¹⁶ Furthermore, EPCOR indicated that in the years after the planned completion of the AMI project in 2017, the company “will be able to avoid the lion share of the impact of the higher testing and replacement requirements because its meters will be new and, as such, will not require any significant compliance testing or replacement for a considerable time period.”⁷¹⁷

652. EPCOR’s evidence demonstrates that over the longer term, electro-mechanical and AMR meters are becoming obsolete as the industry continues to deploy AMI technology as a standard metering option for electric meters.⁷¹⁸ It is this evidence and the evidence on Measurement Canada’s new testing requirements that relate most directly to the issues of need, scope, level and timing of the AMI project under Criterion 1. Process and service improvements, that come with the AMI technology, lend support in the business case for the alternative selected.

653. Consistent with the Commission determinations in Decision 3100-D01-2015 referenced above, from a longer term perspective, the Commission finds reasonable EPCOR’s decision to implement the AMI project in the 2015 to 2017 period in order to maintain system reliability and safety over time, while reducing costs over the 20-year study period, thereby reducing rates in the longer term.

654. Regarding Mr. Bell’s view that the AMI project could have been undertaken in the past, the Commission accepts EPCOR’s explanation that it did not apply for this project prior to the 2014-2015 capital tracker application, in light of the Commission’s concerns with EPCOR’s 2010 AMI proposal set out in Decision 2010-505.

655. Mr. Bell also expressed his view that the AMI project should not be afforded capital tracker treatment because the Commission denied Y factor treatment for AltaGas’ AMR program in Decision 2012-237.⁷¹⁹ The Commission agrees with EPCOR’s argument⁷²⁰ that the Commission’s rejection of AltaGas’ application for Y factor treatment is not germane to a determination of EPCOR’s capital tracker application.

656. The Commission has reviewed the business case and engineering study provided by EPCOR and the evidence on the record of this proceeding with respect to the AMI project. For the reasons above, the Commission finds that the information provided by EPCOR supports a finding that the project is required during the 2016-2017 forecast period and over the longer term to maintain service reliability and safety at adequate levels.

6.4.2.2 AMI as a least-cost solution to the customer revenue metering function

657. Consistent with the approach used in its 2014-2015 capital tracker application, in this application, EPCOR considered four alternatives, including the AMI project, to performing its customer revenue metering function. The four alternatives were:

⁷¹⁶ Exhibit 20407-X0233, EPCOR argument, paragraph 224.

⁷¹⁷ Exhibit 20407-X0233, EPCOR argument, paragraph 224.

⁷¹⁸ Exhibit 20407-X0082, Appendix A-19, paragraph 134.

⁷¹⁹ Decision 2012-237, paragraph 703.

⁷²⁰ Exhibit 20407-X0233, EPCOR argument, paragraph 244.

- The status quo, which would involve the current practice of installing AMR meters to support new growth and replacement meter needs and which would replace all analog meters over a 20-year period.
- The AMR drive-by solution would supplant walking meter readers with vehicles driving through neighbourhoods.
- The AMI project.
- The AMR solution using a fixed network.

658. EPCOR then performed a cost-benefit analysis of the four alternatives, largely using the same methodology and assumptions as set out in its 2014-2015 capital tracker application. Specifically, EPCOR performed a net present value (NPV) analysis of the four alternatives from a revenue requirement perspective, as well as from a cash flow perspective over a 20-year period from 2014 to 2034. Under EPCOR's NPV net cash flow analysis, the present value of project costs is deducted from the present value of the expected benefits. Under this analysis, a project with the highest NPV would be selected. EPCOR's NPV of revenue requirement analysis reflects a reduction in the revenue requirement and, therefore, the largest negative value would normally be chosen.⁷²¹

659. In the present application, EPCOR updated this analysis to reflect the actual contracted AMI system prices and meter installation rates. In responses to IRs from the UCA⁷²² and the Commission,⁷²³ EPCOR provided explanations for any differences in forecast project costs between this application and the 2014-2015 application. EPCOR also included in the updated analysis, the annual cost increases or decreases reflecting the proposed acceleration of the depreciation of EPCOR's non-AMI meters. As well, EPCOR updated the AMI project cost-benefit analysis to include the effect of the Commission's 2013 Generic Cost of Capital (GCOC) Decision 2191-D01-2015⁷²⁴ and other changes in assumptions between the 2014-2015 capital tracker application and the current application.

660. Table 23 below provides a reconciliation of the NPV net cash flow and revenue requirement analyses for the AMI project between the 2014-2015 capital tracker application and this application, as provided in an IR response to the Commission⁷²⁵ and later revised in a corrected undertaking to the CCA.⁷²⁶

⁷²¹ Decision 3100-D01-2015, paragraph 651.

⁷²² Exhibit 20407-X0155, EDTI-UCA-2015JUN26-006(a) and (b).

⁷²³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050(a).

⁷²⁴ Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.

⁷²⁵ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050(c).

⁷²⁶ Exhibit 20407-X0223.02.

Table 23. The AMI project NPV reconciliation between this application and the 2014-2015 capital tracker application⁷²⁷

	Change in assumptions	Change in net cash flow	Change in revenue requirement
		(\$ million)	
1	2014–2015 business case	36.11	(33.67)
2	Using contracted AMI system prices and installation rates	(0.92)	1.02
3	Change in EDTI capital overhead rate (decrease in rate from 6% to 1%)	2.38	(2.49)
4	Change in WACC rate (decrease in rate from 6.99% to 6.50%)	4.04	(3.67)
5	Impact of accelerated depreciation	(0.09)	0.09
6	Hard operating cost increases and benefits during current PBR term	(6.63)	6.63
7	Changes in operating benefit/costs due to update with 2014 actuals	(2.83)	2.28
8	2016-2017 business case (corrected)	32.07	(29.82)

661. EPCOR provided similar NPV reconciliation analyses for the three other alternatives to the AMI project in an IR response to the Commission⁷²⁸ and later revised in a corrected undertaking to the CCA.⁷²⁹

Table 24. Net present value analysis of alternatives to AMI⁷³⁰

Alternative	Net cash flow NPV	Revenue requirement reduction NPV
	(\$ million)	
Alternative 1 - Status quo	(26.87)	21.71
Alternative 2 - AMR drive-by	19.78	(17.23)
Alternative 3 - AMI	32.07	(29.82)
Alternative 4 - AMR network	19.28	(17.10)

662. With reference to the results reproduced in the above table, EPCOR indicated that the AMI alternative provides the highest financial benefits and the greatest reduction in revenue requirement for customers. The status quo (Alternative 1) reflects the capital and operating cost increases that customers will incur if EPCOR continues with its current practice of installing AMR meters to support growth and replacement needs. Based on the results of this analysis, EPCOR concluded that the implementation of the AMI project (Alternative 3) is “clearly the superior option that provides the greatest financial benefit to customers and the best technology platform choice for the years ahead.”⁷³¹ In argument, EPCOR stated its “analysis shows that an alternative project could not be undertaken at lower cost and that there are significant cost savings as a result of completing this project.”⁷³²

⁷²⁷ Exhibit 20407-X0223.02, Table EDTI-AUC-2015JUN26-050-1 (Revised), page 1 of 8.

⁷²⁸ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050(d).

⁷²⁹ Exhibit 20407-X0223.02.

⁷³⁰ Exhibit 20407-X0223.02, Table EDTI-AUC-2015JUN26-050-4 (Revised), Revised Table 5.1-1, page 3 of 8.

⁷³¹ Exhibit 20407-X0082, Appendix A-19, paragraph 128.

⁷³² Exhibit 20407-X0233, EPCOR argument, paragraph 235.

663. Specifically, as part of the NPV net cash flow analysis, EPCOR indicated that the AMI project will result in significant long-term capital and operating cost savings (in each of three operating categories: meter reading, meter operations, and distribution operations) for customers.⁷³³ The bulk of the quantifiable benefits from the AMI project are from operating savings.⁷³⁴ EPCOR's NPV analysis showed that the AMI project has negative net cash flow in years 2014 to 2017, when an initial capital investment for the project exceeding some \$70 million is made. In 2018, the net cash flow becomes positive in the amount of approximately \$10 million annually, until 2034.⁷³⁵ Based on EPCOR's NPV of revenue requirement analysis, the AMI project is expected to result in annual increases to EPCOR's revenue requirement in 2015 to 2017 (with the maximum annual increase to its revenue requirement occurring in 2017), after which customers will enjoy reductions in the revenue requirement each year thereafter.⁷³⁶

664. In an IR, the CCA explored some of the assumptions and inputs to EPCOR's cost-benefit analyses such as the estimated operating costs and the 20-year analysis time frame, and sensitivity to exchange rate fluctuations.⁷³⁷ The UCA, in an IR, requested explanations for any differences in forecast project costs between this application and the 2014-2015 application.⁷³⁸ Neither the UCA nor the CCA disputed the results of EPCOR's updated cost-benefit analysis showing the AMI project to be the least-cost alternative to performing the customer revenue metering function, over the 20-year time frame.

Commission findings

665. In Decision 3100-D01-2015, the Commission found EPCOR's cost-benefit analysis for the AMI project, including the two NPV analyses, to be reasonable.⁷³⁹ In this application, EPCOR provided a similar cost-benefit analysis of the four alternatives to performing the customer revenue metering function, largely using the same methodology and assumptions as in its 2014-2015 capital tracker application. However, EPCOR updated this analysis to include the actual negotiated and contracted costs of the AMI system and meter installation services, the annual cost increases or decreases reflecting the proposed acceleration of the depreciation of conventional meters, and other changes in assumptions between the 2014-2015 capital tracker application and the current application such as the Commission determinations in the 2013 GCOC Decision 2191-D01-2015.

666. In their information requests, the Commission and interested parties explored the assumptions and inputs to EPCOR's cost-benefit analyses (NPV net cash flow analysis and NPV of revenue requirement analysis). In response to the CCA IRs, EPCOR provided explanations on certain assumptions and inputs to its cost-benefit analyses such as the estimated operating costs and the 20-year analysis time frame, and sensitivity to the exchange rate impact.⁷⁴⁰ In response to a UCA IR, EPCOR provided explanations for any differences in forecast project costs between this application and the 2014-2015 application.⁷⁴¹ In response to Commission IRs, EPCOR

⁷³³ Exhibit 20407-X0082, Appendix A-19, paragraphs 82-106.

⁷³⁴ Exhibit 20407-X0082, Appendix A-19, Table 4.3.1-1 on page 22.

⁷³⁵ Exhibit 20407-X0082, Appendix A-19, Table 4.3.1-1 on page 22.

⁷³⁶ Exhibit 20407-X0082, Appendix A-19, paragraph 120, revised in Exhibit 20407-X0223.02, pages 2-3 of 8.

⁷³⁷ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-020(a) to (f).

⁷³⁸ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-006(a) and (b).

⁷³⁹ Decision 3100-D01-2015, paragraph 661.

⁷⁴⁰ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-020(a) to (f).

⁷⁴¹ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-006(a) and (b).

provided a reconciliation between the NPV numbers provided in the 2014-2015 business case and the current business case for the AMI project, as shown in Table 23 above. EPCOR provided a similar reconciliation for each of the three other alternatives considered.⁷⁴² Neither the CCA nor the UCA objected to the results of EPCOR's updated cost-benefit analyses.

667. In Section 6.4.2.3, the Commission approves EPCOR's forecast project costs, based on the actual negotiated and contracted costs of the AMI system and meter installation services, as reasonable. The Commission has reviewed EPCOR's updated NPV analyses provided in this application, reflective of the actual negotiated and contracted costs and updated assumptions that materialized between the 2014-2015 capital tracker application and the current application, and finds them reasonable.

668. In Section 6.4.1.2 of this decision, the Commission did not approve EPCOR's proposal for the accelerated depreciation of existing non-AMI meters and directed EPCOR to remove the accelerated depreciation amounts from the K factor calculations associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project. From the NPV reconciliation analysis provided in EDTI-AUC-2015JUN26-050,⁷⁴³ as revised in a corrected undertaking to the CCA,⁷⁴⁴ the Commission observes that the incremental effect of the accelerated depreciation is a decrease of some \$0.9 million in both the net cash flow NPV and the revenue requirement reduction NPV for alternatives 2, 3 and 4, presented in the Table 24. As such, even when the accelerated depreciation amounts are removed from consideration, the AMI project still has the highest net cash flow NPV and revenue requirement reduction NPV.

669. Based on the evidence in the present proceeding, the Commission continues to find that, over the 20-year period presented in the business case, the AMI project represents the least cost alternative for performing the customer revenue metering function for EPCOR.

6.4.2.3 Scope, level, timing and the associated 2016-2017 forecast costs of the AMI project

670. EPCOR indicated it is implementing the AMI project from 2014 to 2017 in two phases. Phase 1 consists of constructing and testing the AMI network infrastructure, including collectors and all computer hardware and software, and installing approximately 10,000 AMI "smart" meters to test the system. Following the conclusion of Phase 1, scheduled to be completed by the end of 2015, where EPCOR will confirm the successful deployment of the AMI infrastructure and seamless integration with existing applications, Phase 2 will begin. Phase 2 will occur over 2016 and 2017 and will involve replacing the majority of EPCOR's approximately 365,000 existing meters (composed of a mix of electro-mechanical meters and electronic AMR meters) with AMI meters.⁷⁴⁵ Table 25 below provides further details on the AMI project schedule:

⁷⁴² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050(a) to (d), as later corrected in Exhibit 20407-X0223.02.

⁷⁴³ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050(c) to (d).

⁷⁴⁴ Exhibit 20407-X0223.02.

⁷⁴⁵ Exhibit 20407-X0082, Appendix A-19, paragraphs 21-22.

Table 25. The AMI project schedule, 2014-2017⁷⁴⁶

Project step description		2014	2015	2016	2017
1	Vendor selection (RFP, evaluation, contract negotiation)	X			
2	Develop change management/customer communication plans	X			
3	Plan and deploy communications network		X		
4	Integrate AMI system with EDTI systems		X		
5	Training operational resources		X		
6	Install 10,000 meters and verify system performance		X		
7	Execute customer communication plan		X	X	X
8	Mass replacement of meters (approximately 20,000 per month)			X	X
9	Project cleanup (hard to access meters, etc.)				X

671. In response to a Commission IR, EPCOR confirmed that it has made no project schedule changes and has not experienced any project delays since the time of the 2014-2015 capital tracker application.⁷⁴⁷ At the oral hearing, EPCOR provided updates on the status of the AMI project, indicating that Phase 1 of the AMI project is well underway and the results have been better than anticipated;⁷⁴⁸ that EPCOR has commenced the ordering of meters for Phase 2;⁷⁴⁹ and that the AMI project remains on track and on budget for completion in 2017.⁷⁵⁰

672. Forecast capital additions associated with this project were \$32.74 million in 2016 and \$26.07 million in 2017, as shown in the table below. Table 26 below also demonstrates that although there were capital expenditures in 2014, there were no capital additions for this project in 2014. Further, even though there were capital additions for the AMI project in 2015, EPCOR did not include them in the accounting test for this project. As shown in Table 2 from Section 4 of this decision, the K factor portion associated with the AMI project is \$2.12 million in 2016 and \$5.89 million in 2017.

⁷⁴⁶ Exhibit 20407-X0082, Appendix A-19, paragraph 23.

⁷⁴⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050 (b).

⁷⁴⁸ Transcript, Volume 4, page 656, lines 9-25 (Mr. Reimer).

⁷⁴⁹ Transcript, Volume 4, page 656, lines 9-25 (Mr. Reimer).

⁷⁵⁰ Transcript, Volume 5, page 780, lines 15-17 (Mr. Reimer).

Table 26. The AMI project 2014-2017 forecast costs⁷⁵¹

	Costs	2014 actual	2015 forecast	2016 forecast	2017 forecast	Total
		(\$ million)				
1	Opening CWIP		0.30			
2	Capital expenditures					
3	Customer and public consultation		0.28	0.15	0.11	0.54
4	Materials/others	0.01	5.35	25.96	20.64	51.96
5	Labour		1.72	0.36	0.44	2.52
6	Engineering	0.01	0.04	0.04		0.09
7	Contractor	0.24	4.09	5.87	4.57	14.77
8	Salvage proceeds/contributions					
9	Vehicles			0.04	0.05	0.09
10	Allocated overhead	0.02	0.11	0.32	0.26	0.71
11	AFUDC	0.01				0.01
12	Total capital expenditures	0.30	11.59	32.74	26.07	70.70
13	Closing CWIP	0.30				
14	Total capital additions (rows 1+12-13)	0	11.89	32.74	26.07	70.70

Note: Some totals appear incorrect due to rounding.

673. EPCOR described its RFP, evaluation methods, shortlisting and testing procedures for the AMI project in its business case. RFPs were issued in June 2014 for the evaluation and selection of an AMI system vendor (for meters and network system) and a meter installation contractor. On August 29, 2014, EPCOR received RFP responses from six AMI system vendors and three meter installation contractors. In the business case, EPCOR provided details of these vendors' proposals.⁷⁵² EPCOR further indicated that its evaluation team consisted of cross functional resources and included an AMI consultant with significant experience with AMI installations.⁷⁵³

674. The winning bidder for the AMI system component of the project satisfied the project requirements at a cost in line with other shortlisted vendor solutions. Costs were established in a fixed price contract in U.S. dollars for services, and fixed unit prices in U.S. dollars for the equipment and software supplied. The winning bid included life cycle costs for the AMI system of \$50.16 million, based on an exchange rate of \$1.09 Canadian dollars for one U.S. dollar (CAD/USD), the going (i.e., spot) exchange rate at the time of the RFP responses.⁷⁵⁴ For purposes of estimating the forecast cost of the AMI system and services contract, EPCOR used a weighted average rate of \$1.21 CAD/USD, based on forecast spending in 2015, 2016 and 2017 using rates of \$1.27, \$1.25 and \$1.15 CAD/USD, respectively.

675. EPCOR indicated it followed similar processes in connection with the selection of an installation contractor. The selected meter installation contractor represented the lowest cost

⁷⁵¹ Based on data in Exhibit 20407-X0082, Appendix A-19, Table 3.3-1 on page 11.

⁷⁵² Exhibit 20407-X0082, Appendix A-19, Table 3.6-1 on page 15 and Table 3.6-2 on page 16.

⁷⁵³ Exhibit 20407-X0082, Appendix A-19, paragraph 42.

⁷⁵⁴ Exhibit 20407-X0082, Appendix A-19, paragraphs 44-45.

option,⁷⁵⁵ \$8.50 million in Canadian dollars.⁷⁵⁶ EPCOR indicated that all installation costs are paid in Canadian dollars.⁷⁵⁷

676. EPCOR explained that the cost for the contracted installation of meters has been established based on a rate (in Canadian dollars) per meter type, fixed for the duration of the project. Annual forecast costs for installation are based on the number of each meter type forecast to be deployed, multiplied by the installation rate.

677. Other project costs such as hardware, software, and project integration work had been refined based on established business requirements and detailed requirements for the selected vendor solutions.⁷⁵⁸

678. Neither the UCA nor the CCA raised any issues with EPCOR's forecast project costs based on negotiated contracted prices, including the costs of the AMI system component reflective of the forecast CAD/USD exchange rate. However, as discussed further in this section, the CCA recommended that in making a future determination of whether the AMI project costs were prudent, the Commission should consider whether a fixed exchange rate should have been "locked in" through the use of hedging instruments such as currency forward contracts.⁷⁵⁹

679. In the business case, EPCOR provided the following discussion of the CAD/USD exchange rate impact on the AMI project:

... At the time of the RFP responses, the cost of a US dollar was \$1.09 CDN, however since the end of August 2014 the cost for a US dollar has risen and stabilized ranging between \$1.24 - \$1.27 CDN. For purposes of estimating the cost of the AMI system and services contract for this Business Case and Engineering Study, EDTI has used a weighted average rate of \$1.21 CDN based on forecast spending in 2015, 2016, and 2017 using rates of \$1.27, \$1.25, and \$1.15 CDN respectively. While the cost of the US dollar is projected to be lower in 2017, EDTI notes that if the cost of a US dollar were to remain at \$1.25 for the life of the project, the resulting cost increase only be approximately [\$1.75 million or 2.47%]⁷⁶⁰ of the total value of the project.⁷⁶¹

680. In response to a Commission's IR, EPCOR confirmed that because the winning AMI system vendor is a U.S.-based company, EPCOR will be exposed to fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar in the 2015 to 2017 period, for the duration of the AMI contract. However, EPCOR indicated it decided not to hedge this exposure for two principal reasons: because EPCOR received a reduction in the negotiated overall contract value as a result of a discount extended by the AMI system vendor for a fixed-price contract in U.S. dollars; and because the currency forecasts available at the time pointed to partial recovery in the

⁷⁵⁵ Exhibit 20407-X0082, Appendix A-19, paragraphs 45 to 48.

⁷⁵⁶ Exhibit 20407-X0082, Appendix A-19, paragraphs 44-45.

⁷⁵⁷ Exhibit 20407-X0082, Appendix A-19, paragraph 70.

⁷⁵⁸ Exhibit 20407-X0082, Appendix A-19, paragraphs 69-71.

⁷⁵⁹ Exhibit 20407-X0238, CCA reply argument, paragraphs 122-128.

⁷⁶⁰ Revised numbers as in Exhibit 20407-X0154, EDTI-CCA-2015JUN26-020(e).

⁷⁶¹ Exhibit 20407-X0082, Appendix A-19, paragraph 69.

value of the Canadian dollar in 2016 and 2017, when the majority of services, equipment, and software would be purchased.⁷⁶²

681. EPCOR noted the actual discount amount cannot be disclosed because of the confidentiality terms in the AMI system contract. However, EPCOR indicated the discount received was comparable to, or even higher than, the costs associated with hedging the contract, at the time.⁷⁶³ EPCOR commented on its currency exposure risk mitigation processes as follows:

EDTI has not taken any steps to mitigate currency exposure risk for the AMI vendor contract and is not considering any at this time. As discussed in the response to (a) above, EDTI consulted with EPCOR Treasury representatives to discuss possible options to mitigate the currency exposure risk. The primary option discussed was to purchase a hedge based on the anticipated specific amounts and dates of funds needed over the project timeline. At that time, the approximate hedge rate quotes were ranging from \$1.2410 to \$1.2422 USD/CAD. At the same time, the futures market was forecasting the USD/CAD exchange rate to decline to an average of \$1.22 over the project timeline, representing a \$0.84 million premium (i.e., higher cost) between the hedge contract and the forecast future spot value. Given the positive directional indication of future exchange rates and how rapidly rates had risen to that point, EDTI decided that it was not a prudent course of action to enter into a hedge in an attempt to guard against the potential for a continued rise in exchange rates. EDTI continues to monitor the exchange rate and futures market which continues to indicate a larger increase in the value of the Canadian dollar in 2016 than originally forecast at the time of contract negotiations back in late January.

682. EPCOR also indicated that in order to purchase a hedge, precise payment dates and amounts needed to be known⁷⁶⁴ and this degree of precision was not available in connection with the AMI project.

683. In its reply argument, similar to its recommendations on the debt costs set out in Section 7.2, the CCA recommended that the Commission consider the CAD/USD currency hedge rates and costs available at the time of the forecast, in the evaluation of the actual cost of purchasing U.S. dollars for payments to the AMI system vendor.⁷⁶⁵ In this regard, the CCA did not agree with EPCOR's reasons that hedging the exchange rate exposure would not be practical if it is not known when a particular amount of U.S. dollars will be required.

EDTI knows the approximate amount and timing to be paid and if it were prudent could hedge accordingly. It may not be a perfect hedge but it would accomplish much of the objective. If EDTI had concerns about timing, it could hedge earlier – particularly as the cost of holding the surplus funds until needed in these times of low interest rates is very low.⁷⁶⁶

⁷⁶² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-051(a) and (b).

⁷⁶³ Transcript, Volume 5, page 790, lines 2-21 (Mr. Reimer and Mr. Baraniecki).

⁷⁶⁴ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-051(b).

⁷⁶⁵ Exhibit 20407-X0238, CCA reply argument, paragraphs 122-128.

⁷⁶⁶ Exhibit 20407-X0238, CCA reply argument, paragraph 130.

Commission findings

684. The Commission observes that the scope, level and timing of the AMI project proposed in this application are the same as EPCOR put forward in its business case for this project as part of the 2014-2015 capital tracker application. The Commission finds it significant that EPCOR has made no project schedule changes and has not incurred any project delays since the time of the 2014-2015 capital tracker application.⁷⁶⁷ In the Commission's view, the fact that EPCOR maintained the original project schedule, even though the company did not receive approval for capital tracker treatment for the project in Decision 3100-D01-2015, lends support to the reasonableness of the project scope, level and timing as proposed in the 2014-2015 capital tracker application, as reapplied for in the present application.

685. As set out in Table 26 above, EPCOR's forecast capital additions associated with this project are \$32.74 million in 2016 and \$26.07 million in 2017. These forecast costs are largely based on the contracted rates for the AMI system and related services (in U.S. dollars) and the meter installation price (in Canadian dollars), that EPCOR negotiated with respective successful bidders as a result of an RFP process, and meter replacement volumes (approximately 20,000 meters per month) expected to be undertaken in 2016 and 2017.

686. Regarding the volume component, EPCOR confirmed during the hearing in an exchange with Commission counsel that the volume of meter replacements is expected to proceed in accordance with the schedule:

Q. ... So is your expectation of ramping up to 20,000 meters per month and installing all meters by the end of 2017, is it realistic, especially in light of implementation problems that other utilities have experienced?

A. MR. REIMER: No, I think we're very confident that we'll be done by then. A project team that I've put together is fully engaged. They're doing very well. The relationships with the vendors we've chosen are going well.

And I think with the installation contractor, in particular, having just completed work in Saskatchewan and being familiar with our winters and things like that, we have a very high degree of confidence that we will proceed as per schedule.⁷⁶⁸

687. EPCOR further indicated that the terms of the contract with the successful AMI system bidder includes a project delivery schedule for key activities and deliverables. The contract also addresses key requirements for resourcing commitments and meter availability.⁷⁶⁹

688. Regarding the contracted rates for the AMI system and meter installation services, the Commission has reviewed the information regarding EPCOR's RFP process provided in the business case and IR responses and is satisfied that the process undertaken was reasonable. EPCOR confirmed it had no pre-existing business relationship with either the selected AMI vendor or the meter installation contractor.⁷⁷⁰ The Commission is satisfied that the cost of the AMI system and related services (in U.S. dollars) and the meter installation price (in Canadian dollars), proposed by winning vendors in a competitive bidding process are reflective of

⁷⁶⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-050(b).

⁷⁶⁸ Transcript, Volume 5, page 784, lines 1-14 (Mr. Reimer).

⁷⁶⁹ Exhibit 20407-X0082, Appendix A-19, paragraph 32.

⁷⁷⁰ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-051(f).

competitive market prices. The Commission finds these costs to be reasonable in the circumstances.

689. Because all meter installation costs are paid in Canadian dollars, there is no foreign currency exchange risk considerations for this component of the AMI project. However, the CAD/USD exchange rate risk implications for the AMI system and related services component, for which the costs were established in a fixed price contract in U.S. dollars, requires further consideration.

690. EPCOR indicated that each of the six AMI system vendors that submitted RFP responses were Canadian subsidiaries of foreign companies which required dealing with the issue of foreign currency exchange risk. The Commission accepts as reasonable EPCOR's RFP evaluation and its choice of the winning bidder, based on the spot exchange rate of \$1.09 CAD/USD at the time of the RFP process. The Commission also finds reasonable EPCOR's decision to enter into a fixed-price contract in U.S. dollars, based on testimony that the discount received for entering into the contract was comparable to, or even higher than, the costs associated with hedging the contract, at the time.⁷⁷¹ The Commission accepts as reasonable, for purposes of forecasting the costs of the AMI system component of the project in Canadian dollars, the weighted average forecast rate of \$1.21 CAD/USD, based on forecast spending in 2015, 2016 and 2017 for this project and the exchange rates of \$1.27, \$1.25 and \$1.15 CAD/USD, respectively. No party objected to the use of these exchange rates. However, as EPCOR pointed out, the exchange rate risk in this case is that the actual cost incurred by EPCOR for purchasing U.S. dollars required to pay the AMI system vendor is greater than EPCOR's forecast exchange rate of \$1.21 CAD/USD on which the forecast costs for the AMI system component of this project were based.⁷⁷²

691. While the CCA did not object to EPCOR's forecast project costs based on the weighted average forecast rate of \$1.21 CAD/USD, the CCA did not agree with EPCOR's reasons as why hedging the CAD/USD exchange rate exposure for the duration of the AMI contract was not practical. The CCA recommended that the Commission consider, in future true-up capital tracker prudence reviews of the project, the actual cost of purchasing the U.S. dollars for making payments to the AMI system vendor, relative to the CAD/USD currency hedge rates and associated costs of "locking in" a certain exchange rate available to the company at the time of the forecast.⁷⁷³

692. Mr. Baraniecki noted that even though EPCOR had made a decision not to hedge the CAD/USD exchange rate exposure at the time, EPCOR continues to "look at hedging longer term" and that it will "continue to evaluate and think about it" and may or may not reconsider this decision in the future.⁷⁷⁴ The Commission will not mandate EPCOR to hedge the CAD/USD exchange rate exposure for the duration of the AMI contract. However, the onus remains on the company to demonstrate in any capital tracker true-up application, that the actual project costs, in Canadian dollars, were prudent.

⁷⁷¹ Transcript, Volume 5, page 790, lines 10-21 (Mr. Baraniecki).

⁷⁷² Exhibit 20407-X0146, EDTI-AUC-2015JUN26-051(d).

⁷⁷³ Exhibit 20407-X0238, CCA reply argument, paragraphs 122-128.

⁷⁷⁴ Transcript, Volume 5, page 795 line 7 to page 796, line 6 (Mr. Baraniecki).

693. In assessing the prudence of EPCOR's 2015 to 2017 actual project costs, the Commission will consider the evidence brought forward by all parties in the respective capital tracker true-up applications, that supports, or objects to, the reasonableness of the actual project costs in Canadian dollars. This evidence may include consideration of forward curve CAD/USD exchange rates, forecast CAD/USD rates published in reputable sources, hedging costs or any other indicators that support a party's position.

694. In light of findings made by the Commission above and in each of sections 6.4.2.1 and 6.4.2.2, the Commission finds that the information provided by EPCOR supports a finding that the scope, level, timing and forecast costs for the AMI project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.

6.4.2.4 Other considerations

695. In the business case for the AMI project, EPCOR addressed issues related to the implementation of the AMI project, including customer communications, data security, safety performance of the selected AMI meters and providing customers with the ability to opt out of the program.

696. EPCOR indicated that its efforts relating to this project have benefited significantly from its engagement with other Canadian and U.S. utilities that have invested in AMI technology. In 2011, EPCOR visited Hydro Quebec, Sask Power and FortisAlberta to discuss each utility's AMI program. EPCOR stated it incorporated into its analysis information acquired from studying the AMI deployments of these utilities. For example, EPCOR noted that one of the key observations was that each of the visited utilities used a 20-year analysis period in their business cases to align with the expected replacement timeframe of the system.⁷⁷⁵

697. EPCOR indicated that it was aware of customer concerns with respect to AMI deployments in other regions of Canada and the United States. These concerns relate to exposure to wireless radio frequency waves, the security and privacy of their meter data, and the safety of their new meter installation. In response to a commission IR, EPCOR described some of the learnings it had gained with respect to the implementation of AMI networks from other Canadian utilities. These learnings included communication strategies for the transition from conventional meters to the AMI system and advice on implementing and running the IT system for AMI, training staff to use the new system and the ongoing maintenance and care of the AMI meters.⁷⁷⁶

698. EPCOR indicated that a key success factor commonly noted by utilities where deployments have gone relatively smoothly, is a strong communication plan that provides timely and factual information to customers. In response to a UCA IR, EPCOR discussed the nature of the risks associated with customers having limited awareness relating to the project, or not supporting the project, or having negative experiences during the project.⁷⁷⁷ To address these concerns, EPCOR indicated it "has budgeted costs for a dedicated communications expert and a multi-faceted customer communication plan that includes a mix of customer direct-delivery printed information, website information, and live agent customer assistance during the

⁷⁷⁵ Exhibit 20407-X0082, Appendix A-19, paragraph 49.

⁷⁷⁶ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-052(a).

⁷⁷⁷ Exhibit 20407-X0155, EDTI-UCA-2015JUN26-007(a).

installation period.”⁷⁷⁸ In response to a Commission IR, EPCOR also indicated it was in the process of setting up a dedicated phone line and email inbox where customers can be directed to additional information and answers to specific questions and concerns.⁷⁷⁹ EPCOR expressed its belief that these measures would ensure that customers have the necessary awareness and information to understand the various aspects of the technology being deployed, including how the technology works, the benefits of meter reading automation, concerns with wireless radio frequency exposure and the security/privacy of their data.

699. With respect to network security and customer privacy, EPCOR stated it “fully subscribes” to the governing regulations regarding the collection, use, and disclosure of personal information, as discussed in the AUC Smart Grid Inquiry Report and publishes its Privacy Policy for Personal Information on its website. EPCOR pointed out that modern AMI systems are designed with a full suite of security features that mirror those of highly secure internet sites that offer e-commerce services, such as:⁷⁸⁰

- AES data encryption (128 or 256 bit) from the host control computer (located securely within corporate firewalls) to the meter,
- Secure Socket Layer (SSL) protocol for host applications,
- Use of digitally signed certificates in field tools that require authentication at the host control computer protecting meter access by un-authorized devices,
- Digital certificates for authenticated messages (disconnects, firmware upgrades),
- Local user authentication for access to the control computer to ensure access by only utility authorized personnel,
- Digital authentication by the control computer of any Home Area Network (HAN) devices connected to the meter to prevent unauthorized access to specific meter data,
- Firewall segmentation, and
- Audit events for review of all servers, firewalls, and other device access/changes.

700. EPCOR is taking additional measures to protect the security of its systems and customer data through a combination of available technology security tools, audit procedures, and appropriate authentication procedures.

701. Regarding concerns with respect to meter installation safety, EPCOR noted the following:

In July, 2014 concerns regarding the safety of newly installed meters were raised after a number of meters were involved in fires in Saskatchewan. A subsequent independent incident investigation performed by Ritenburg and Associates Ltd. concluded that moisture and contaminants within the meter was a major factor in the meter failures and ensuing fires. The report also found no evidence that the meter failures were caused by the meter installation itself or by hot sockets that can sometimes occur if a meter socket was damaged or in need of repair. EDTI has studied the report findings and to ensure that these potential issues are addressed in the context of its AMI project, EDTI, as part of its evaluation of responses to the RFP, had careful regard for the design and historical performance of each proposed meter type and the meter installation contractors’ training

⁷⁷⁸ Exhibit 20407-X0082, Appendix A-19, paragraph 4.

⁷⁷⁹ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-052(a)(v).

⁷⁸⁰ Exhibit 20407-X0082, Appendix A-19, paragraph 5.

and quality assurance processes to ensure their meter exchange practices were of the highest standard.⁷⁸¹

702. During the oral hearing, EPCOR confirmed that it selected a different manufacturer for the AMI meters than the meters that had issues in Saskatchewan. EPCOR also indicated that the vendor chosen by EPCOR has not had a single incident of a meter fire similar to those experienced in Saskatchewan, and that the vendor has considered the type of defects found in Saskatchewan and has quality controls in place to guard against such defects.⁷⁸²

703. EPCOR stated the company is well acquainted with efforts in the electric utility industry and by international standards bodies, to specify appropriate standards for AMI systems. EPCOR has actively participated in the Smart Grid Standards committee of the Canadian Electrical Association, which interrelates with the North American Electric Reliability Council, the Institute of Electrical and Electronics Engineers, the American National Standards Institute and the U.S. National Institute of Standards and Technology.

704. EPCOR also pointed out that its AMI RFP evaluation required that prospective system proponents confirm their compliance with all required standards, and where standards are not applicable, EPCOR required vendors to demonstrate that any proprietary elements are field-proven.⁷⁸³

705. Finally, EPCOR shared its observation that recent AMI deployments in other regions across North America, including larger Canadian utilities such as BC Hydro and Hydro Quebec, have included “opt out” programs for customers not wanting an AMI meter installed at their location. These programs are generally designed to permit customers to “opt out” of the installation of an AMI meter provided the customer pays the incremental costs associated with a non-standard meter in the form of a one-time charge and an ongoing monthly charge to cover the cost of reading the meter manually. EPCOR indicated it plans to amend its terms and conditions and specific costs for customers that desire to “opt out” of the installation of an AMI meter as part of its 2016 annual PBR rate adjustment application.

706. Subsequent to filing this application, EPCOR proposed changes to its 2016 terms and conditions of service (T&Cs) to give effect to the implementation of the AMI project as part of its 2016 annual PBR rate adjustment filing. In Decision 20821-D01-2015, the Commission approved these amendments to EPCOR’s T&Cs, based on the understanding that the AMI project will be implemented regardless of whether capital tracker treatment is granted to its associated costs.⁷⁸⁴ EPCOR’s new approved T&Cs give an opportunity to customers who do not want an AMI meter installed at their location, an option to opt out of the AMI program and use the conventional meter, subject to paying the associated “Non-Standard Meter Reading Fee” of \$15.20 per month and “Non-Standard Meter Installation Fee” of \$79.86.⁷⁸⁵

707. In its 2016 annual PBR rate adjustment filing, EPCOR also indicated that it will be alerting its customers of their option to not have an AMI meter installed and of the costs

⁷⁸¹ Exhibit 20407-X0082, Appendix A-19, paragraph 7.

⁷⁸² Transcript, Volume 5, page 800, line 9 to page 801, line 9 (Mr. Reimer).

⁷⁸³ Exhibit 20407-X0082, Appendix A-19, paragraph 10.

⁷⁸⁴ Transcript, Volume 4, page 649, line 16 to page 650, line 10 (Mr. Baraniecki).

⁷⁸⁵ Decision 20821-D01-2015, paragraph 131.

associated with exercising this option, prior to the start of the AMI meter installations, to the extent possible. In Decision 20821-D01-2015, the Commission directed EPCOR to address how it implemented these customer awareness measures in its next annual PBR rate adjustment filing.⁷⁸⁶

Commission findings

708. The Commission considers that measures taken by EPCOR to deal with the matters of customer communications relating to the AMI project, data security, safety performance of the selected AMI meters and providing customers with the ability to opt out of the program provide additional reassurance to the Commission that the scope, level, timing and associated forecast costs for the project are reasonable, as proposed by EPCOR.

6.4.2.5 Y or Z factor treatment for the AMI project

709. As mentioned in Section 6.4.2.1 of this decision, neither the CCA nor the UCA opposed EPCOR implementing the AMI project outside of the capital tracker mechanism. The interveners explored the idea of the AMI project potentially qualifying for either Y factor or Z factor treatment. According to the interveners, Y factor or Z factor treatment would involve a consideration of all costs and benefits in determining the revenue requirement calculations for the project, rather than including only depreciation, taxes and return, as is done for K factor purposes.

710. In Decision 2012-237, the Commission set out the following criteria for consideration of Z factor treatment:

524. Accordingly, the Commission considers that the following criteria will apply when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

- (1) The impact must be attributable to some event outside management's control.
- (2) The impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business.
- (3) The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.
- (4) All costs claimed as an exogenous adjustment must be prudently incurred.
- (5) The impact of the event was unforeseen.

525. The Commission considers that all of the above criteria must be met in order for an item to qualify for a Z factor rate adjustment.

711. In the same decision, the Commission's considerations for Y factor treatment were set out as follows:

631. The ability to recover costs outside of the I-X mechanism should be an extraordinary remedy for cost recovery. If however, the company has no ability to influence the amount of certain costs and those costs are material in nature and not otherwise recoverable under the I-X mechanism, incentives are unaffected. Accordingly,

⁷⁸⁶ Decision 20821-D01-2015, paragraph 132.

the Commission adopts and clarifies the criteria established in Decision 2009-035 for the identification of eligible Y factor costs as follows:

- 1) The costs must be attributable to events outside management's control.
- 2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
- 3) The costs should not have a significant influence on the inflation factor in the PBR formulas.
- 4) The costs must be prudently incurred.
- 5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

632. The Commission considers that all criteria must ordinarily be satisfied before a cost will be considered for Y factor treatment. In addition to those Y factors that meet the above criteria, the Commission will allow companies to recover as Y factor rate adjustments specific costs incurred at the direction of the Commission and flow-through costs that are similar in nature to the flow-through items approved for ENMAX [ENMAX Power Corporation] in Decision 2009-035. The Commission considers that having fewer Y factor accounts will make the PBR plans easier to administer. Y factors will only be approved in circumstances where there is a demonstrable need for them.

712. In his evidence for the CCA, Mr. Thygesen expressed his view that the AMI project is either a Y factor or a Z factor, probably "more of a Z factor due to its unique, one time nature."⁷⁸⁷ According to Mr. Thygesen, the AMI project satisfies the requirements of the first criterion for both Z factor and Y factor treatment, that the proposed costs must be attributable to events outside management's control, because the AMI project is being implemented due to an exogenous event; namely, a change to the Measurement Canada meter testing standards. As such, Mr. Thygesen stated that EPCOR has "no control" over the initiating event, stating the "key concept running through the Commission's decisions respecting both Y and Z is that the factors or events are exogenous and outside the company's control, not that the underlying event or cause be a disaster."⁷⁸⁸

713. Regarding the fifth Z factor criterion, that the impact of the event has to be unforeseen, Mr. Thygesen discussed in his evidence that this requirement does not mean that a Z factor event has to be sudden, unexpected and cannot involve a studied response. Mr. Thygesen concluded that "the fact that EPCOR appears to be taking a prudent course of action by seeking Commission approval ahead of a response to a major exogenous event does not invalidate AMI as a Z factor."⁷⁸⁹

714. Mr. Thygesen pointed out that in Decision 2013-060,⁷⁹⁰ the Commission approved a Z factor for ENMAX for recovery of the Uniform System of Accounts/Minimum Filing Requirements (USA/MFR) implementation costs. In Mr. Thygesen's view, this approved Z factor can be considered similar to EPCOR's AMI project, "in the sense that like AMI a

⁷⁸⁷ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 37.

⁷⁸⁸ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 40.

⁷⁸⁹ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 52.

⁷⁹⁰ Decision 2013-060: ENMAX Power Corporation Application for Recovery of Costs Uniform System of Accounts and Minimum Filing Requirements, Proceeding 1386, Application 1607567-1, February 26, 2013.

change to systems and processes was identified ahead of time and implementation took place over an extended period of time.”⁷⁹¹

715. Mr. Thygesen highlighted that in Decision 2013-060, the Commission recognized that ENMAX was directed to implement USA/MFR by the Alberta Energy and Utilities Board (board), predecessor to the Commission.⁷⁹² Mr. Thygesen stated that the change to Measurement Canada standards “is akin to the Board’s decision respecting USA/MFR. Both requirements necessitate systems and processes change. Both are made by a body external to the company.”⁷⁹³

716. As a summary of the above considerations, Mr. Thygesen stated in his evidence that the “CCA recommends that the AMI project be approved for treatment as a Z factor with annual true-ups.”⁷⁹⁴

717. In its argument, the CCA agreed with Mr. Thygesen’s evidence. The CCA pointed out that in Proceeding 3100, EPCOR’s testimony was that the AMI project was driven by changes to Measurement Canada rules.⁷⁹⁵ The CCA expressed its view that “AMI is clearly not a capital tracker/K factor but rather a Y or Z factor forced upon it by exogenous changed or revised requirements from Measurement Canada.”⁷⁹⁶ The CCA further clarified that although it is “largely indifferent to whether the project is a Y or Z factor,” the CCA “believes it is more of a Z factor due to its unique, one time nature whereas Y factors are more due to ongoing, recurring activities.”⁷⁹⁷

718. Mr. Bell, for the UCA, indicated in his evidence that if the AMI project “is truly intended to resolve changes in regulations, then paragraph 743 of Decision 2012-237 applies, and the project is a Z-Factor.”⁷⁹⁸ In response to a Commission IR, Mr. Bell clarified his position on this issue as follows:

First, to be clear, Mr. Bell does not agree that the AMI project should qualify as a capital tracker. Further, as the Commission already ruled that the AUI AMR program does not qualify as a Y-Factor adjustment, it is difficult to see how one could now approve the EDTI AMI program as a Y-Factor. With regard to Z-Factors, there are clearly defined criteria that must be satisfied in order for costs to qualify as a Z-Factor. As this application does not propose Z-Factor treatment, nor is there evidence on the record to test each of the Z-Factor criteria, it would be inappropriate to consider Z-factor treatment until such time as there is a Z-Factor application before the Commission. Again, as noted above, if the Commission were to find that the primary driver of the implementation of the AMI project is a change in regulations, such as Measurement Canada rules, then the project may qualify as a Z-Factor.⁷⁹⁹ [emphasis in original]

⁷⁹¹ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 30.

⁷⁹² Decision 2013-060, paragraph 34.

⁷⁹³ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 41.

⁷⁹⁴ Exhibit 20407-X0163, CCA evidence of Mr. Thygesen, paragraph 56.

⁷⁹⁵ Exhibit 20407-X0234, CCA argument, paragraph 128.

⁷⁹⁶ Exhibit 20407-X0234, CCA argument, paragraph 125.

⁷⁹⁷ Exhibit 20407-X0234, CCA argument, paragraph 132.

⁷⁹⁸ Exhibit 20407-X0156, UCA evidence of Mr. Bell, page 3.

⁷⁹⁹ Exhibit 20407-X0171, UCA-AUC-2015JUL30-001(b).

719. Mr. Bell also indicated that “if the Commission finds that the driver is not a change in regulations, then the AMI project likely fails on criteria 1 and 5 for Z-factor treatment” that require the exogenous event to be outside management’s control and be unforeseen. Mr. Bell further stated that if the driver for the project was not the change in regulations, then the decision to implement AMI is most likely within management control.⁸⁰⁰

720. The UCA did not make any comments on whether the AMI project qualifies for Y factor or Z factor treatment in its argument or reply argument.

721. EPCOR submitted that the potential use of a Y factor or a Z factor for the AMI project would not be appropriate, given the Commission’s criteria that must be met to qualify for Y or Z factor treatment. EPCOR did not agree with the interveners’ views that the AMI project is required to be undertaken due to a change in regulations and, therefore, it fails to satisfy the first criterion for both Y and Z factor treatment that the costs must be attributable to an event outside of management’s control. In response to Mr. Bell, EPCOR stated in its rebuttal evidence:

...The changes in Measurement Canada requirements that provide the opportunity to realize substantial cost savings for customers over the long term through the AMI project do not require that the AMI project be undertaken. In other words, EDTI is not being forced to implement AMI by changes in regulation as, for example, would have been the case had the provincial government enacted regulations forcing Alberta utilities to implement smart meters/grids.⁸⁰¹

722. EPCOR provided a similar response to Mr. Thygesen:

EDTI’s evidence in this current proceeding, as it was in Proceeding ID 3100, is clear that the project was initiated to achieve cost savings separate and apart from the changes in Measurement Canada requirements. What the changes in Measurement Canada requirements did was to improve the long-term economics of the project for EDTI’s customers’ benefit, making it the most cost effective choice by far among potential alternatives. While the change in Measurement Canada requirements was one of the factors taken into account by EDTI in determining that the AMI project was the most cost effective way forward, these requirements are not the sole driver for the project.⁸⁰²
[footnotes omitted]

723. EPCOR noted Mr. Thygesen’s view that the Commission’s approval in Decision 2013-060 of the recovery by ENMAX of its operating and capital costs associated with implementing and sustaining USA/MFR as a Z factor, is relevant to the AMI project. EPCOR responded that ENMAX was directed by the board to implement the USA/MFR and, thus, was effectively forced to implement USA/MFR and was given no discretion in the matter. By contrast, EPCOR stated it has not been forced to implement the AMI project by any direction of a regulator or other government authority.⁸⁰³

724. Ultimately, EPCOR did not agree that the AMI project is beyond the discretion of EPCOR’s management and is instead required by an exogenous event. EPCOR concluded that:

⁸⁰⁰ Exhibit 20407-X0171, UCA-AUC-2015JUL30-002.

⁸⁰¹ Exhibit 20407-X0173, EPCOR rebuttal evidence, page 11.

⁸⁰² Exhibit 20407-X0173, EPCOR rebuttal evidence, page 33.

⁸⁰³ Exhibit 20407-X0173, EPCOR rebuttal evidence, page 32.

... the AMI project is first and foremost driven by the opportunity to achieve long term savings for customers and the financial incentives available to EDTI under PBR to reduce EDTI's operating costs over the PBR term. EDTI's management has chosen to implement the AMI project as opposed to a different approach as the project provides the most prudent means of minimizing its Customer Revenue Metering operating and capital costs for customers over the long term, including under Measurement Canada's revised requirements.⁸⁰⁴

725. The matter was discussed further during the oral hearing, in the following exchange between EPCOR witness, Mr. Baraniecki and Commission counsel:

Q. Mr. Baraniecki, I would like to start off with you, sir, where we left off yesterday talking about Y, Z, and K factors. And you've indicated that the S.S.06 changes, the Measurement Canada requirements, were not the sole driver of the AMI project. But would EDTI be undertaking the AMI project if it were not for these regulatory changes?

A. MR. BARANIECKI: Yes. EDTI would continue to undertake the AMI project if it were not for the changes in the S.S.06 requirements. Just note that the -- even if you strip out the costs of complying with S.S.06 in the business case and you assume they just didn't exist and we didn't have to deal with them, the project still is net present value positive. And that would have been the reason we would have gone ahead with it.

Q. And would you have been going ahead in the same timeframe?

A. MR. BARANIECKI: Yes.⁸⁰⁵

726. Mr. Reimer provided further clarification on the evolving role of Measurement Canada standards changes in contributing to the need of the AMI project over time, starting from the first AMI application in 2010:

Q. Okay. So back to the earlier question. Your position with respect to the driver of the project you said has evolved. So what was the driver at the start, back in 2010?

A. MR. REIMER: Purely operational savings to customers.

Q. And the driver was not S.S.06?

A. MR. REIMER: Not at that time, no.

Q. And the role of S.S.06 in your thinking has increased over time once the magnitude of the costs of the status quo option became more defined; is that fair?

A. MR. REIMER: That's fair, yes.⁸⁰⁶

727. Additionally, in response to a Commission IR, EPCOR expressed its view that the AMI project did not appear to meet the Commission's fifth criterion for Z factor treatment that the effect of the event was unforeseen. According to EPCOR, the AMI project is different from a

⁸⁰⁴ Exhibit 20407-X0173, EPCOR rebuttal evidence, pages 33-34.

⁸⁰⁵ Transcript, Volume 5, page 757 line 13 to page 758, line 6 (Mr. Baraniecki).

⁸⁰⁶ Transcript, Volume 5, page 762, line 21 to page 763, line 7 (Mr. Reimer).

sudden, exogenous event that requires action on a utility owner's part to respond quickly, incurring costs to address the event and then coming to the Commission after the fact for approval to recover the costs under a Z factor. Instead, the AMI project reflects a studied response to a change in Measurement Canada requirements that have been known for some time, allowing EPCOR to consider and choose among alternative means of carrying out its customer revenue metering function.⁸⁰⁷

728. In his evidence from Proceeding 3100 filed on the record of this proceeding, Mr. Bell stated that if the AMI project is approved for capital tracker treatment, "all operating cost benefits must be included in the CT [capital tracker] calculation."⁸⁰⁸ Mr. Bell confirmed this view in his evidence for this proceeding stating: "Should the AUC decide to grant some form of relief to EDTI for its AMI program, it must also ensure that all benefits are also passed to customers"⁸⁰⁹ in an IR response to the Commission.⁸¹⁰

729. EPCOR responded that in Decision 2013-435, the Commission determined that efficiency gains during the PBR term would not be appropriated to fund capital projects that otherwise qualified for capital tracker treatment, and would not form part of the double-counting analysis.⁸¹¹

Commission findings

730. The Commission has considered the evidence of the parties with respect to Y factor or Z factor treatment of the AMI project. The Commission notes the EPCOR rebuttal evidence where the company indicated that while the changes in Measurement Canada requirements improved the long-term economics of the project, "making it the most cost effective choice by far among potential alternatives," these requirements were not the sole driver for the project.⁸¹² Further, during the hearing, in an exchange with Commission counsel, EPCOR's management clearly indicated that the company would still have undertaken the AMI project in the absence of changes to Measurement Canada meter testing requirements.⁸¹³

731. Based on the company's evidence as to what motivated its decision to proceed with the AMI project and what its actions would have been in the absence of a change to Measurement Canada's meter testing requirements, the Commission finds that the implementation of the AMI project cannot be considered attributable to an event outside management's control and, therefore, the project does not satisfy the first criterion for both the Y factor and Z factor treatment, as set out in Decision 2012-237.⁸¹⁴

732. The interveners submitted that if the AMI project is approved for capital tracker treatment, the Commission should consider whether all costs and benefits should be included in

⁸⁰⁷ Exhibit 20407-X0146, EDTI-AUC-2015JUN26-053 and Exhibit 20407-X0233, EPCOR argument, paragraph 70.

⁸⁰⁸ Exhibit 20407-X0170, UCA-AUC-2015JUL30-003 (Attachment), Appendix B, Evidence of Russ Bell from Proceeding 3100, black lined version, page 14.

⁸⁰⁹ Exhibit 20407-X0156, UCA evidence of Mr. Bell, page 5.

⁸¹⁰ Exhibit 20407-X0171, UCA-AUC-2015JUL30-001(b).

⁸¹¹ Decision 2013-435, paragraphs 211-218.

⁸¹² Exhibit 20407-X0173, EPCOR rebuttal evidence, page 33.

⁸¹³ Transcript, Volume 5, page 757, line 13 to page 758, line 6 (Mr. Baraniecki).

⁸¹⁴ Decision 2012-237, paragraphs 524-525 (Z factor criteria) and 631-632 (Y factor criteria).

the revenue requirement calculations for the project, rather than including only depreciation, taxes and return, as is done for the K factor purposes. As EPCOR pointed out, the Commission considered this matter in Decision 2013-435, where it made the following determination at paragraph 218:

218. ... the Commission is satisfied that, when viewed in their entirety, the PBR plans approved in Decision 2012-237 ensure that customers share the expected efficiency gains, independent of the actual performance of the companies. In order to preserve the incentives of the approved PBR plans, the Commission finds that no consideration of O&M savings and potential productivity offsets above those implied by the approved X factor should form part of the companies' double-counting analysis.

733. Consistent with these determinations, if approved for capital tracker treatment, any non-capital benefits resulting from the AMI project will accrue to EPCOR during the PBR term. This is consistent with the incentives created under the PBR plan. Ongoing benefits of this nature will accrue on a go forward basis, to customers, subsequent to a re-basing or future GTA. Any reduction in capital costs arising from the AMI project (such as lower capital costs for the Customer Revenue Metering – Growth & Life Cycle Replacements project) will be passed on to customers during the PBR term through the capital tracker mechanism. As set out in Section 5.2.1, the Commission directed EPCOR to group these projects together for purposes of the K factor calculation.

6.4.2.6 Commission's conclusions on the AMI project

734. In Section 6.4.2.1, the Commission determined that the AMI project is required during the 2016-2017 forecast period and over the longer term to maintain service reliability and safety at adequate levels. The Commission confirmed in Section 6.4.2.2, that over the 20-year period presented in the business case, the AMI project represents the least cost alternative for performing the customer revenue metering function for EPCOR. In Section 6.4.2.3, the Commission found the scope, level, timing and forecast costs for the AMI project to be reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1. Subject to these adjustments and directions, the Commission also found the total annual cost forecasts to be reasonable for 2016 and 2017. Finally, in Section 6.4.2.4, the Commission indicated that certain other considerations, addressed by EPCOR, that relate to the AMI project such as customer awareness, network security and customer privacy, meter installation safety, commitment to standards and interoperability, among others, provide reassurance to the Commission that the scope, level, timing and associated forecast costs for the project are reasonable, as proposed by EPCOR.

735. Given the above, and subject to the adjustments and Commission directions applicable to all projects set out in Section 6.1 of this decision, the Commission finds that the AMI project satisfies the project assessment requirement of Criterion 1.

7 Accounting test under Criterion 1 – the project must be outside of the normal course of the company’s ongoing operations and Commission conclusion on Criterion 1

7.1 Accounting test for the 2014 true-up and 2016-2017 forecast

736. As explained in Decision 2013-435, the purpose of the accounting test is to determine whether a project or program (depending on the approved level of grouping) proposed for capital tracker treatment is outside the normal course of the company’s ongoing operations. This is achieved by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program.⁸¹⁵

737. In Decision 2013-435, the Commission determined that the accounting test should be based on a “project net cost approach,” which is sufficient to satisfy the Commission that all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company’s ongoing operations, as required to satisfy Criterion 1. Under this approach, the extent to which a project is underfunded by the I-X mechanism is calculated by comparing the forecast or actual revenue requirement for that project to the going-in revenue historically associated with a similar type of capital expenditure escalated by I-X and including the effect on revenue of any changes in billing determinants.⁸¹⁶ The impact on revenue of any changes in billing determinants, which is calculated as the forecast percentage change in billing determinants in any given PBR year, was referred to as “Q”⁸¹⁷ or “Q factor.”

738. As set out in Section 4.4 of Decision 2013-435, the accounting test, as it relates to revenue calculations, consists of two components. The first component is the revenue provided under the I-X mechanism for a project or program proposed for capital tracker treatment. As explained in Decision 3434-D01-2015, this component of the accounting test utilizes the WACC rate embedded in a company’s approved going-in rates⁸¹⁸ and requires assumptions regarding the values for the I-X index and Q for each year.

739. The second component is the revenue requirement calculations based on the forecast or actual capital additions for that project or program for a given PBR year, approved by the Commission as part of the project assessment review under Criterion 1. As set out in Decision 3434-D01-2015, for purposes of the revenue requirement calculations, this component of the accounting test requires assumptions regarding the current year’s WACC rate; namely, cost of debt, approved ROE and capital structure, including preferred shares.⁸¹⁹

740. The first component of the accounting test, the calculation of revenue provided under the I-X mechanism, was provided in Schedule 1.⁸²⁰ EPCOR’s calculation of the accounting test model for the 2014 capital tracker true-up, was provided in the corrected and revised Schedule 2.⁸²¹ EPCOR’s accounting test model for the 2016 and 2017 capital tracker forecast, was

⁸¹⁵ Decision 2013-435, paragraphs 149-150.

⁸¹⁶ Decision 2013-435, paragraphs 262-263.

⁸¹⁷ Decision 2013-435, paragraph 499.

⁸¹⁸ Decision 3434-D01-2015, paragraph 37.

⁸¹⁹ Decision 3434-D01-2015, paragraph 40.

⁸²⁰ Exhibit 20407-X0133, Schedule 1.

⁸²¹ Exhibit 20407-X0134.02, revised Schedule 2.

provided in corrected and revised Schedule 3⁸²² and Schedule 4,⁸²³ respectively. In addition, for continuity purposes, EPCOR also provided revised accounting test schedules for years 2013⁸²⁴ and 2015.⁸²⁵

741. In Decision 3100-D01-2015, the Commission established that the accounting test for a capital tracker true-up application for a given year, should utilize the approved I-X index and the Q factor based on the final approved forecast of billing determinants for that year.⁸²⁶ For the 2014 capital tracker true-up, EPCOR used the 2014 I-X index of 1.59 per cent approved in Decision 2013-462. The 2014 Q factor of 1.96 per cent was based on EPCOR's forecast billing determinants, approved in the same Decision 2013-462.⁸²⁷

742. In Decision 3100-D01-2015, the Commission also acknowledged that for purposes of a capital tracker forecast, a company may be required to estimate the I factor and Q factor for the coming year.⁸²⁸ In the accounting test for 2016 and 2017, EPCOR used I factor values of 1.58 per cent and 0.95 per cent, respectively, resulting in an I-X index value of 0.42 per cent for 2016 and negative 0.21 per cent for 2017.⁸²⁹ The forecast I factor values were calculated using the methodology approved in Decision 2012-237, and were based on Dr. David Ryan's 2016 and 2017 inflation forecasts.⁸³⁰ EPCOR's 2016 and 2017 Q factors of 3.76 per cent and 2.15 per cent, respectively, were based on preliminary forecasts of billing determinants for those years.⁸³¹

743. Regarding the WACC rate, for purposes of both the 2014 capital tracker true-up and the 2016-2017 capital tracker forecast, EPCOR used the WACC rate of 6.96 per cent embedded in its going-in rates in the first component of the accounting test.⁸³²

744. For the second component of the accounting test, for the 2014 true-up, EPCOR used the actual 2014 WACC rate of 6.50 per cent,⁸³³ based on the actual weighted average cost of debt (WACD) of 5.30 per cent, the approved equity thickness of 40 per cent and the approved ROE of 8.3 per cent, as determined in the 2013 GCOC Decision 2191-D01-2015. For the purposes of the 2016-2017 capital tracker forecasts, EPCOR used the actual 2014 WACC rate of 6.50 per cent as a forecast for these years, subject to a true-up.⁸³⁴

745. No party raised issues with EPCOR's I-X and Q factor values, nor with the WACC rate of 6.96 per cent used in the first component of its accounting test. In addition, no party raised issues with the 2014 actual WACC rate of 6.50 per cent used in the second component of the accounting test for 2014. Similarly, the inflation rates for 2016 and 2017, Q factors and the ROE and capital structure components of WACC, forecast for 2016 and 2017, were not challenged by

⁸²² Exhibit 20407-X0135.02, revised Schedule 3.

⁸²³ Exhibit 20407-X0136.02, revised Schedule 4.

⁸²⁴ Exhibit 20407-X0148, EDTI-AUC-2015JUN26-031 Attachment 1.

⁸²⁵ Exhibit 20407-X0150, EDTI-AUC-2015JUN26-031 Attachment 3.

⁸²⁶ Decision 3100-D01-2015, paragraphs 577-578.

⁸²⁷ Exhibit 20407-X0130.02, revised application, paragraph 224.

⁸²⁸ Decision 3100-D01-2015, paragraph 579.

⁸²⁹ Exhibit 20407-X0133, Schedule 1, Tab 2, lines 116-117.

⁸³⁰ Exhibit 20407-X0003, Appendix E.

⁸³¹ Exhibit 20407-X0002 Appendix F.

⁸³² Exhibit 20407-X0133, Schedule 1, line 116.

⁸³³ Exhibit 20407-X0130.02, revised application, Table 2.7.2-1 on page 93.

⁸³⁴ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-012(b).

any party. However, as discussed in Section 8.2, the CCA brought forward some issues with respect to the forecast cost of debt component of the 2016 and 2017 WACC rates.

Commission findings

746. The Commission has reviewed EPCOR's schedules that make up its accounting test analysis for the purposes of the 2014 capital tracker true-up and the 2016 and 2017 capital tracker forecasts and finds these schedules to be reasonable and generally consistent with the accounting test methodology approved in Decision 2013-435. The Commission has also assessed the reasonableness of EPCOR's WACC, I-X and Q factor assumptions used in the first component of the accounting test, and WACC assumptions in the second component of the accounting test, for each of 2014, 2016 and 2017. The Commission's findings are set out below.

747. The Commission has verified that for the first component of the accounting test, EPCOR used the correct WACC rate of 6.96 per cent, embedded in its approved 2012 going-in rates, as required by Decision 3434-D01-2015. The Commission has verified also that for the 2014 true-up, EPCOR used the correct values for the I-X index and Q factor, as approved in Decision 2013-462.

748. When the application was filed, EPCOR did not have approved values for either the I-X index or Q factor for 2016 or 2017. Therefore, it used the I-X index value of 0.42 per cent for 2016 and negative 0.21 per cent for 2017,⁸³⁵ calculated using the methodology approved in Decision 2012-237, and based on Dr. David Ryan's 2016 and 2017 inflation forecasts.⁸³⁶ In the same vein, EPCOR's 2016 and 2017 Q factors of 3.76 per cent and 2.15 per cent, respectively, were based on preliminary forecasts of billing determinants for those years.⁸³⁷

749. In Decision 3100-D01-2015, the Commission accepted in principle, the use of such forecasting methods when the final approved numbers are not available. For the purposes of this decision, the Commission considers EPCOR's forecast I factor and Q values for 2017 to be reasonable. The forecast values of the I and Q factors will be trued up to approved numbers as part of the 2017 capital tracker true-up application.

750. Regarding the 2016 forecast, the Commission observes that, since the filing of the application, the 2016 I-X index of 0.90 per cent and billing determinants forecast were approved in Decision 20821-D01-2015.⁸³⁸ To minimize future true-ups, the Commission directs EPCOR, in its compliance filing to this decision, to use the approved 2016 I-X index value and the Q factor based on the forecast billing determinants approved in Decision 20821-D01-2015 for purposes of its 2016 capital tracker forecast accounting test.

751. As discussed earlier in this section, in Decision 3434-D01-2015, the Commission determined that revenue requirement calculations in the second component of the accounting test should be based on the current year's WACC rate, which, in turn, is calculated based on the actual or forecast cost of debt, as well as the approved ROE and capital structure for that year.⁸³⁹

⁸³⁵ Exhibit 20407-X0133, Schedule 1, Tab 2, lines 116-117.

⁸³⁶ Exhibit 20407-X0003, Appendix E.

⁸³⁷ Exhibit 20407-X0002 Appendix F.

⁸³⁸ Decision 20821-D01-2015, paragraphs 23 and 49.

⁸³⁹ Decision 3434-D01-2015, paragraph 40.

With the exception of the forecast debt cost component of WACC discussed in Section 8.2, no party raised concerns with EPCOR's calculations of either the 2014 actual or 2016 and 2017 forecast WACC rates.

752. In Section 8.2 below, the Commission finds EPCOR's 2014 actual WACD of 5.30 per cent to be reasonable for purposes of the accounting test. The Commission also finds EPCOR's forecast WACD rates of 5.30 per cent for each of 2016 and 2017, reflecting the 2014 actual debt rate, to be reasonable for purposes of the accounting test, subject to a true-up.

753. Therefore, the Commission finds EPCOR's 2014 actual WACC of 6.50 per cent used in the second component of its accounting test, based on the 2014 actual WACD of 5.30 per cent, as well as the approved equity thickness of 40 per cent and the approved ROE of 8.3 per cent from Decision 2191-D01-2015, to be reasonable. The Commission also finds EPCOR's forecast WACC of 6.50 per cent, based on the 2014 actual WACC, to be reasonable. In future capital tracker true-up applications for 2016 and 2017, these forecast WACC rates will be trueed up to the actual cost of debt and the approved ROE and capital structure for those years, which will be determined in a future GCOC proceeding.

754. For the reasons above, the Commission is satisfied that EPCOR's accounting test model sufficiently demonstrates that all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company's ongoing operations, as required to satisfy the accounting test component of Criterion 1. The Commission's determinations on whether EPCOR's projects or programs proposed for capital tracker treatment in 2014 on an actual basis and in 2016 and 2017 on a forecast basis, satisfy both the accounting test and the project assessment components of Criterion 1, are set out in Section 8.3.

7.2 2014 actual and 2016-2017 forecast debt rates used in the accounting test

755. As set out in Section 8.1, consistent with the directions in Decision 3434-D01-2015, EPCOR used in the second component of its accounting test for the 2014 true-up, the actual 2014 WACC rate of 6.50 per cent,⁸⁴⁰ based on the 2014 actual WACD of 5.30 per cent, the approved equity thickness of 40 per cent and the approved ROE of 8.3 per cent from Decision 2191-D01-2015. In turn, the 2014 WACD of 5.30 per cent is a blend of EPCOR's new \$75 million long-term debt issue in 2014 with the coupon rate of 4.19 per cent, and rates for 11 prior debt issues dating back to 1999, as set out in EPCOR's 2014 Rule 005⁸⁴¹ filing.⁸⁴²

756. For the purposes of the 2016-2017 capital tracker forecast, EPCOR used the actual 2014 WACC rate of 6.50 per cent as a forecast for these years. In response to a CCA IR,⁸⁴³ EPCOR explained that by utilizing this WACC rate, EPCOR in effect used its actual WACD from 2014 of 5.30 per cent as its forecast cost of debt for 2016 and 2017. EPCOR expressed its view that the actual cost of debt in 2014 represents the best information known at the time the forecasts were made. EPCOR also noted it will true-up these forecast debt rates to the actual cost of debt for 2016 and 2017 in future capital tracker true-up applications for these years.

⁸⁴⁰ Exhibit 20407-X0130.02, revised application, Table 2.7.2-1 on page 93.

⁸⁴¹ Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

⁸⁴² Exhibit 20407-X0173, EPCOR rebuttal evidence, page 26.

⁸⁴³ Exhibit 20407-X0154, EDTI-CCA-2015JUN26-012(b).

757. In its rebuttal evidence,⁸⁴⁴ EPCOR further pointed out that this method of forecasting debt costs for the 2016-2017 period is consistent with the methodology approved by the Commission in Decision 3434-D01-2015. The Commission stated the following in paragraph 77 of that decision:

77. The debt forecasts to be used in the second component of the accounting test for 2016 and 2017 should be based on the best information that is known by the companies at the time they make their forecasts, meaning that they should include the impacts of their most recent actual debt and preferred share issuances in developing their forecasts, along with all outstanding historical debt and preferred share issuances, but the companies are not required to forecast the movement of interest rates in the future. For example, if a company knows it will need to issue debt in a forecast year it may forecast the rate for that future debt issuance based on the rate that resulted from the company's most recent debt issuance. The Commission also notes that the cost of debt and preferred shares will ultimately be trued-up to actuals, as discussed further in Section 3.3.

758. In its evidence, the CCA submitted that because debt rates have been falling since 2014, as demonstrated by the drop in the *Consensus Forecast* estimates, EPCOR's forecast of 5.3 per cent for 2016 and 2017 is overstated.⁸⁴⁵ However, during the oral hearing⁸⁴⁶ and in its argument⁸⁴⁷ (as further discussed below), the CCA confirmed that it is not proposing any changes to EPCOR's forecast debt rates.

759. The CCA observed that the use of forward curve rates as a basis for forecasting and the possibility for a utility to lock in a debt rate through the use of forward or futures debt markets were among the issues discussed in Proceeding 3539 dealing with EPCOR Transmission's 2015-2017 tariff application. The CCA pointed out that in his evidence in Proceeding 3539, Dr. Evans for EPCOR, referenced forward curve debt rates that were lower than the *Consensus Forecast* numbers. Accordingly, given the difference between the 2016 and 2017 forecast and forward curve rates, the CCA submitted that consideration should be given, particularly for 2017, to locking in some or all of EPCOR's 2017 financing requirements by way of a forward contract.⁸⁴⁸

760. The CCA further expressed its view that because debt costs are recovered from customers on an actual basis, EPCOR is economically indifferent to the rate at which it issues debt and thus has no incentive to secure the lowest cost of debt. The CCA recommended the following:

In situations where the forecast rate is higher than the forward rate it may be advisable to hedge a portion of the debt requirements. In the same way that EPCOR manages foreign exchange risk, so to it may be advisable to manage interest rate risk. Alternatively, based on the forecast rate increases it might be advisable for EPCOR to secure all of its financing for the test period early and amortize the interest paid for amounts which are not yet required over the life of the debt. This is akin to a homeowner paying a penalty to refinance their mortgage at a lower rate. Whether it makes sense depends upon the

⁸⁴⁴ Exhibit 20407-X0173, EPCOR rebuttal evidence, pages 24-25.

⁸⁴⁵ Exhibit 20407-X0163, CCA evidence, paragraph 12.

⁸⁴⁶ Transcript, Volume 5, page 853, lines 19-20 (Mr. Thygesen).

⁸⁴⁷ Exhibit 20407-X0234, CCA argument, paragraph 17.

⁸⁴⁸ Exhibit 20407-X0163, CCA evidence, paragraph 13.

particular circumstances such as the time between issuance and need and the interest rate spread.⁸⁴⁹

761. In its argument, the CCA noted paragraph 77 of Decision 3434-D01-2015 referenced by EPCOR and clarified:

To be clear, the CCA is not proposing any change to the recommendations of the Decision. The CCA is not proposing that EDTI change its forecast, only that the Commission take into account, at true-up, the forward curve rates that could have been locked in as compared to the actual rates at which debt was issued at. This would be in the same manner in which the Commission assesses prudence when evaluating foreign currency exposure or when a project is forecast to cost \$G and it comes in at \$H. In all cases the variance is identified and the company is expected to support the prudence of its actions. So for example, if EDTI issues debt at significantly higher rates than the current forward curve estimates, then EDTI should have to justify why its actions were prudent...⁸⁵⁰

762. In its rebuttal evidence, EPCOR noted the distinction between the weighted average cost of debt (WACD) rate used in WACC calculations that applies to a historical rate base, and the rate used when issuing new long term debt. With reference to its 2014 Rule 005 schedules, EPCOR pointed out that the newly-issued long term debt plays an exceedingly minor part in the calculation of EPCOR's total WACD. Specifically, EPCOR showed that while the 2014 new debt was issued at a 4.19 per cent rate, EPCOR's 2014 actual WACD (used in its 2016-2017 capital tracker calculations) was 5.3 per cent, reflecting all debt issues that date back to 1999, and is thus a blend of many years of debt issuance that could have been higher or lower than the current debt rate depending on the market conditions of that year.⁸⁵¹

763. EPCOR did not agree with the CCA's view that the company is economically indifferent to the rate at which it issues debt. During the hearing, Mr. Chaudhary outlined the process EPCOR employs to determine when to issue debt:

A. MR. CHAUDHARY: So, Mr. Wachowich, there's a number of factors that are taken into consideration when we determine when to place debt. What EDTI does is we consult with EPCOR's treasury group to understand, you know, I guess, potentially where market trends are headed. We also look at the capital program that is forecast for the year to understand how much debt that we think we should be issuing. So we rely on the treasury group's advice to help us determine when we should issue debt.⁸⁵²

764. Additionally, EPCOR indicated that because the cost of debt used in the capital tracker calculations will be true-up to actuals, the prudence and reasonableness of EPCOR Distribution's actual cost of debt rate will be tested in the capital tracker true-up proceedings. EPCOR further noted that if it used cost of debt rates that were not prudent, the Commission may make disallowances.⁸⁵³

⁸⁴⁹ Exhibit 20407-X0163, CCA evidence, paragraph 15.

⁸⁵⁰ Exhibit 20407-X0234, CCA argument, paragraph 17.

⁸⁵¹ Exhibit 20407-X0173, EPCOR rebuttal evidence, pages 25-27.

⁸⁵² Transcript, Volume 1, page 27, line 23 to page 28, line 7 (Mr. Chaudhary).

⁸⁵³ Exhibit 20407-X0173, EPCOR rebuttal evidence, page 28.

765. With regard to the CCA's proposal that the company give consideration to hedging against a 2017 forecast increase in interest rates by locking into a forward contract for some or all of the 2017 debt requirements, EPCOR expressed its view⁸⁵⁴ that this proposal is inconsistent with the Commission's determination in paragraph 77 of Decision 3434-D01-2015 that "the companies are not required to forecast the movement of interest rates in the future."

766. Additionally, EPCOR submitted that granting the CCA's request would be tantamount to leaving EPCOR "with little choice but to lock-in a forward curve rate now, or risk a finding of imprudence if actual market debt rates at the time EDTI issues its debt prove to be higher than the current forward curve rate."⁸⁵⁵ In EPCOR's view, this result would be inconsistent with the Commission's findings in Decision 3539-D01-2015, where it stated that "the Commission's consideration of the use of the forward curve as a forecast, does not mean that the Commission is required to make a determination on whether EDTI [Transmission] would be required to lock-in its actual cost of debt using the forward curve for the test years."⁸⁵⁶

Commission findings

767. The CCA's argument, as it relates to EPCOR's forecast cost of debt component of its WACC, brings forward two issues: (i) whether EPCOR's forecast WACD of 5.3 per cent, based on its actual 2014 WACD for 2016 and 2017 is reasonable and (ii) whether the Commission should use a forward curve debt rate in its assessment of the prudence of the incurred, actual cost of debt.

768. Regarding the first issue, the Commission considers that EPCOR's debt forecast methodology, which uses the WACD rate reflecting the company's most recent debt issuance as a forecast rate for future debt issuances, is consistent with the method approved at paragraph 77 of Decision 3434-D01-2015, referenced earlier in this section. In its argument, the CCA clarified that "the CCA is not proposing any change to the recommendations of the Decision [3434-D01-2015]. The CCA is not proposing that EDTI change its forecast, only that the Commission take into account, at true-up, the forward curve rates that could have been locked in as compared to the actual rates at which debt was issued at."⁸⁵⁷ During the hearing, Mr. Thygesen for the CCA confirmed that in his evidence for the CCA, he "didn't actually recommend a drop in the rate."⁸⁵⁸

769. The Commission recognizes that in Decision 3539-D01-2015 dealing with the EPCOR Transmission 2015-2017 GTA, the Commission accepted the forward curve as a reasonable indicator of interest rates during the test period and directed EPCOR Transmission to reflect a forecast cost of debt for 2016 based on the 2016 forward curve cost of debt.⁸⁵⁹ However, the Commission is cognizant of the differences in purpose between this decision and Decision 3539-D01-2015. The purpose of Decision 3539-D01-2015 was to set rates for the EPCOR transmission function on a forecast basis, whereas the purpose of this decision is to establish forecast capital tracker amounts as part of a PBR plan for EPCOR's distribution function. Unlike the approved revenue requirement for EPCOR's TFO, the 2016 and 2017 capital tracker

⁸⁵⁴ Exhibit 20407-X0173, EPCOR rebuttal evidence, pages 27-28.

⁸⁵⁵ Exhibit 20407-X0237, EPCOR reply argument, paragraph 35.

⁸⁵⁶ Decision 3539-D01-2015, paragraph 835.

⁸⁵⁷ Exhibit 20407-X0234, CCA argument, paragraph 17.

⁸⁵⁸ Transcript, Volume 5, page 853, lines 19-20 (Mr. Thygesen).

⁸⁵⁹ Decision 3539-D01-2015, paragraphs 836-838.

forecasts approved in this application are subject to a full true-up proceeding (including cost of debt). In light of these differences, the Commission continues to consider that the debt forecasting methodology approved at paragraph 77 of Decision 3434-D01-2015 should continue to be used in EPCOR capital tracker proceedings.

770. On the second issue, the CCA proposed to use the forward curve rates in considering the prudence of the incurred, actual debt rate. However, the CCA did not raise any issues nor did the CCA provide any evidence on, the available forward curve rates to assess the prudence of EPCOR's 2014 actual cost of debt.⁸⁶⁰ Rather, the CCA indicated that its proposal "would be utilized to consider the prudence of the debt issuance in future true-ups."⁸⁶¹ The Commission notes that the onus remains on the company to demonstrate that its actual debt costs, included in the capital tracker true-up accounting test for each year, are reasonable.

771. In Decision 20522-D02-2016,⁸⁶² dealing with AltaGas' 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, the Commission made the following determination regarding the review process to establish the reasonableness of a company's actual debt costs included in the capital tracker true-up accounting test:

329. At paragraph 89 of Decision 3434-D01-2015, the Commission determined that "... the embedded debt rate used in the second component of the accounting test in the true-up process should match the rate that appears on the company's Rule 005 filing from the associated year, and if it does not match, the Commission directs the company to provide an explanation of why it does not match, in its capital tracker true-up application." Therefore, the Commission will accept, in the absence of any evidence that the actual incurred cost of debt was not reasonable, the company's embedded debt rate that appears on the company's Rule 005 filing from the associated year for purposes of the second component of the accounting test in the capital tracker true-up process. This approach recognizes the PBR incentives provided in Decision 2012-237, which allow companies to manage their businesses during the PBR term, to be followed by a prudence review upon re-basing or in a future rate application. Accordingly, the prudence of the debt rates reported in the company's Rule 005 filing during the PBR term will be included in the prudence review at the time of rebasing for purposes of establishing the going-in rates on a go-forward basis for the next generation PBR plan or in a general rate application.⁸⁶³

772. EPCOR's actual 2014 WACD of 5.30 per cent as reported in its Rule 005 filing, is a blend of EPCOR's new \$75 million long-term debt issue in 2014 with a coupon rate of 4.19 per cent, and rates for 11 prior debt issues dating back to 1999. No issues were raised regarding the reasonableness of the 2014 debt issuance in this proceeding. Accordingly, consistent with paragraph 329 of Decision 20522-D02-2016 referenced above and based on the evidence filed in this proceeding, the Commission finds EPCOR's 2014 actual WACD of 5.30 per cent to be reasonable for purposes of the second component of the accounting test in the 2014 true-up process. The prudence of this actual debt will be assessed at the time of rebasing for purposes of

⁸⁶⁰ Transcript, Volume 5, page 858, lines 17-25.

⁸⁶¹ Exhibit 20407-X0234, CCA argument, paragraph 35.

⁸⁶² Decision 20522-D02-2016 AltaGas Utilities Inc. 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, Proceeding 20522, January 21, 2016.

⁸⁶³ Decision 20522-D02-2016, paragraph 329.

establishing the going-in rates on a go-forward basis for the next generation PBR plan or in a GTA.

773. Earlier in this section, the Commission indicated that EPCOR's debt forecast methodology, which uses the WACD rate reflecting the company's most recent debt issuance as a forecast rate for future debt issuances, is consistent with the method approved in paragraph 77 of Decision 3434-D01-2015, which the Commission found preferable for capital tracker application purposes. Given the Commission's approval of the actual WACD rate of 5.30 per cent for 2014, the Commission also finds EPCOR's forecast WACD of 5.30 per cent for each of 2016 and 2017, based on the actual cost of debt in 2014, to be reasonable for purposes of the accounting test. In future capital tracker true-up applications for 2016 and 2017, this forecast WACD will be trued up to the actual cost of debt for those years, as approved by the Commission.

7.3 Commission's conclusions on Criterion 1

774. In Section 6 of this decision, based on the project assessment under Criterion 1, the Commission approved the need, scope, level and timing for each project or program that EPCOR proposed for capital tracker treatment, either on an actual basis for 2014 or on a forecast basis for 2016 or 2017. With the exception of the Customer Revenue Metering – Growth & Life Cycle Replacements project, the Commission also generally confirmed the prudence of actual capital additions for the true up of each of the capital tracker projects or programs in 2014, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision. As well, with the exception of the Life Cycle Replacement and Extension of Underground Distribution Cable and the Customer Revenue Metering – Growth & Life Cycle Replacements project, the Commission determined that EPCOR's forecast capital expenditures for the proposed 2016 and 2017 capital tracker projects are generally reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1 of this decision.

775. Because the adjustments required pursuant to Section 6.1 of this decision affect actual 2014 costs and/or forecast 2016 or 2017 costs for all projects or programs, the Commission cannot make a determination in this decision as to whether any of EPCOR's projects or programs proposed for capital tracker treatment in 2014 on an actual basis, and in 2016 and 2017 on a forecast basis, satisfy the project assessment requirement of Criterion 1.

776. In Section 7.1 of this decision, the Commission found the form of EPCOR's accounting test model to be reasonable and generally consistent with the accounting test methodology approved in Decision 2013-435. However, the Commission directed some changes with respect to EPCOR's accounting test assumptions related to the I-X index and Q factor values for 2016.

777. Accordingly, although the Commission finds the general form of EPCOR's accounting test model to be reasonable and consistent with the methodology approved in Decision 2013-435, the Commission cannot make a determination in this decision as to whether any of EPCOR's projects or programs proposed for capital tracker treatment in 2014 on an actual basis and in 2016 and 2017 on a forecast basis, satisfies the accounting test requirement of Criterion 1 and accordingly, whether any of EPCOR's projects or programs satisfy Criterion 1 in its entirety.

778. The Commission directs EPCOR, in its compliance filing to this decision, to revise its accounting test for 2014, as well as for 2016 and 2017, based on approved final forecast or actual capital additions, the 2016 model assumptions and other directions as set out in the previous sections of this decision. EPCOR is further directed to provide two summary tables in the compliance filing to this decision. The first table will include for each capital tracker project or program, a comparison of the 2014 actual capital additions applied for in this proceeding and the 2014 actual capital additions, revised in accordance with the directions set out in this decision. The second table will provide a similar comparison for the forecast 2016 and 2017 capital trackers.

8 Criterion 2 – ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

779. With respect to Criterion 2, the Commission clarified in Decision 2013-435 that, in addition to asset replacement projects and projects required by an external party, in principle a growth-related project will satisfy the requirements of Criterion 2 where it can be demonstrated that customer contributions, together with incremental revenues allocated to the project on some reasonable basis, when added to the revenue provided under the I-X mechanism, are insufficient to offset the revenue requirement associated with the project in a PBR year.⁸⁶⁴ Certain projects proposed for capital tracker treatment that do not fall into any of the growth-related, asset replacement or external party related categories might also satisfy Criterion 2 in certain circumstances, as discussed in Section 3.2.4 of Decision 2013-435.⁸⁶⁵

780. As set out in Section 3 of this decision, for the purposes of the true-up of the 2014 capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in Decision 3100-D01-2015, there is also no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program has changed. In response to a Commission IR, EPCOR confirmed that “no drivers for any of the previously approved projects or programs have changed.”⁸⁶⁶ Therefore, EPCOR did not provide any additional evidence on how the projects or programs included in the 2014 capital tracker true-up satisfy the requirements of Criterion 2.

781. EPCOR provided information in support of how the projects or programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis, satisfy the requirements of Criterion 2. Table 27 below provides a summary of EPCOR’s evidence with respect to Criterion 2 in support of the 2016 and 2017 capital tracker forecasts.

⁸⁶⁴ Decision 2013-435, paragraph 309.

⁸⁶⁵ Decision 2013-435, paragraph 314.

⁸⁶⁶ Exhibit 20407-X0146, EDTI-AUC-JUN26-004(a).

Table 27. Applied-for 2016-2017 capital tracker projects or programs and Criterion 2 requirements

Project name	Criterion 2 project type	Application paragraph ⁸⁶⁷
Applied-for projects or programs previously approved for capital tracker treatment		
Third-Party Driven Relocations	External party driven/ replacement	256, 270, 282, 291
Life Cycle Replacement and Extension of Underground Distribution Cable	Replacement	321
New 15-kV and 25-kV Circuit Additions	Growth/external party driven	337
New Underground Cable and Aerial Line Reconfigurations and Extensions to Meet Customer Growth	Growth/external party driven	351
Distribution Pole and Aerial Line Life Cycle Replacements	Replacement	369
Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement	Growth/external party driven, also a portion of replacement	383, 372
Capitalized Underground System Damage	Replacement	397
New Underground and Aerial Service Connections for Commercial, Industrial, Multi-family and Misc. Customers	Growth/external party driven	426
Underground Residential Distribution (URD) Servicing – Rebates, Acceptance Inspections & Terminations	Growth/external party driven	441
Capital Tools and Instrument Purchases	Replacement/ external party driven	456
Poundmaker Feeders	Growth	305
OMS/DMS Life Cycle Replacement	Replacement	547
Capitalized Aerial System Damage	Replacement	470
Underground Industrial Distribution (UID) Servicing – Rebates, Acceptance Inspections & Terminations	Growth/external party driven	485
Replacement of Faulted Distribution PILC Cables [Note 1]	Replacement	498
Neighbourhood Renewal Program	Replacement	559
Customer Revenue Metering – Growth & Life Cycle Replacements	Replacement, also a portion of growth/external party driven	516
Life Cycle Replacement of Network Transformers	Replacement	573
Life Cycle Replacement of PILC Cable Systems	Replacement	532
Applied-for projects or programs that have not been previously approved for capital tracker treatment		
Advanced Metering Infrastructure	Replacement	588
North and South Service Center Growth Plan	Replacement/Growth	602
IT Hardware Lifecycle Replacements and Additions	Replacement	617
Rebuild and/or Replace Civil Work for Downtown Vaults and Manholes	Replacement	632
Switching Cubicle Life Cycle Replacement	Replacement	658
Network Reconfigurations	Replacement	671
Street Light Service Connections and Security Lighting Addition and Capital Replacement [Note 2]	Growth/external party driven, also a portion of replacement	646, 636

Note 1: In Decision 3100-D01-2015, the Commission determined that the Replacement of Faulted Distribution PILC Cables project satisfied the requirements of Criterion 2 for 2014 and 2015. However, this project was not afforded capital tracker treatment in 2014 because it did not meet the requirements of other capital tracker criteria on a forecast basis, as set out in the compliance filing Decision 20210-D01-2015, Table 3. This project received capital tracker treatment in 2015, on a forecast basis, as set out in Table 4 of Decision 20210-D01-2015.

⁸⁶⁷ Paragraph numbers in this table refer to Exhibit 20407-X0130.02, revised application.

Note 2: In Decision 3100-D01-2015, the Commission determined that the Street Light Service Connections and Security Lighting Addition and Capital Replacement project satisfied the requirements of Criterion 2 for 2015. However, this project was not afforded capital tracker treatment in 2015 because it did not meet the requirements of other capital tracker criteria on a forecast basis, as set out in the compliance filing Decision 20210-D01-2015, Table 4.

782. As set out in Decision 20210-D01-2015, in response to a Commission direction, EPCOR clarified that some components of the Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement project deal with the replacement of existing capital assets, while others are required by an external party and are growth-related.⁸⁶⁸ The project type in Table 27 for the Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement project reflects this clarification. Additionally, based on the information in the application, the same project type was assigned to the Street Light Service Connections and Security Lighting Addition and Capital Replacement project.

783. With the exception of the AMI project discussed below, no party took issue with EPCOR’s evidence referenced in the table above in support of how the projects or programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis, satisfy the requirements of Criterion 2.

784. In the application, EPCOR indicated that the AMI project meets the requirements of Criterion 2 because it involves the replacement of existing capital assets, and no aspect of the project is required due to system growth, or increases in load or the number of sites on EPCOR’s system.⁸⁶⁹ In argument, EPCOR submitted that although it can be argued that the AMI project does not fit precisely into one of the three categories of projects included in the wording of Criterion 2 (albeit the project involves the replacement of existing assets), the Commission has determined in Decision 2013-435 that projects that do not precisely fit can still qualify for capital tracker treatment:

351. As noted in Section 3.2.1 of this decision, the inclusion of the word “ordinarily” in Criterion 2 means that the criterion does not necessarily restrict capital tracker treatment to projects that fall into one of the above categories (asset replacement, externally driven, and growth-related). Capital projects may arise during the PBR term that do not precisely fit into any of these three categories, but may still be eligible for capital tracker treatment where it can be demonstrated that a project is not adequately funded under the I-X mechanism, and is sufficiently important to the company, so that its ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken. The Commission will consider these projects on an individual, case-by-case basis.⁸⁷⁰

785. In its argument,⁸⁷¹ the UCA submitted that the AMI project does not meet the requirements of the second capital tracker criterion because it is not a project (i) “required for the replacement of aged infrastructure that has come to the end of its useful life,” or (ii) required by a third party, as mandated in paragraph 595 of Decision 2012-237.

⁸⁶⁸ Decision 20210-D01-2015, paragraph 27.

⁸⁶⁹ Exhibit 20407-X0130.02, revised application, paragraph 588.

⁸⁷⁰ Decision 2013-435, paragraph 351.

⁸⁷¹ Exhibit 20407-X0232, UCA argument, paragraph 19.

786. With respect to the first requirement, the UCA contended that there is no evidence that conventional metering assets are at the end of their useful life. According to the UCA, the existence of undepreciated costs associated with the conventional metering assets suggests that these assets are not at the end of their useful life. Further, the UCA submitted that EPCOR acknowledged⁸⁷² it could continue to provide the customer revenue metering function using the conventional metering assets, rather than the AMI meters. Therefore, the replacement of these assets is not required.⁸⁷³

787. Regarding the second aspect of the criterion, the UCA referenced the oral testimony of EPCOR witnesses and contended that the primary driver of the AMI project is not the change in Measurement Canada rules for customer meters and, as such, the project cannot be characterized as being “required” by a third party.⁸⁷⁴

788. In its argument, the CCA questioned whether a regulatory body such as Measurement Canada can be classified as an external party for purposes of Criterion 2.⁸⁷⁵

Commission findings

789. Consistent with the determinations in Section 3 of this decision, because the driver or drivers (e.g., replacement of existing assets, external party, growth) for each project or program included in EPCOR’s 2014 capital tracker true-up has not changed since the Commission undertook and approved proposed capital tracker projects and programs against the Criterion 2 requirements in Decision 3100-D01-2015,⁸⁷⁶ there is no need to undertake a reassessment of these projects or programs against the Criterion 2 requirements.

790. The Commission reminds EPCOR that the following direction from Decision 3100-D01-2015 continues to apply for subsequent capital tracker true-up applications:

616. In subsequent capital tracker true-up applications, the Commission directs EDTI to address whether the driver for any of the previously approved forecast projects or programs has changed, so as to warrant a reassessment under Criterion 2. In the event that the driver of the project or program has changed since the forecast project or program was approved, EDTI is directed to identify such projects and programs and to provide evidentiary support that each project or program continues to satisfy the requirements of Criterion 2.⁸⁷⁷

791. The Commission has reviewed the evidence and the reasons provided by EPCOR in support of its forecast capital projects or programs for 2016 and 2017 proposed for capital tracker treatment, as summarized in Table 27 above. As set out in Section 3 of this decision, for capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in prior capital tracker decisions, there is no need to undertake a reassessment of the project or program against the Criterion 2 requirements

⁸⁷² Transcript, Volume 4, page 572, lines 13-24.

⁸⁷³ Exhibit 20407-X0232, UCA argument, paragraph 20.

⁸⁷⁴ Exhibit 20407-X0232, UCA argument, paragraphs 21-24.

⁸⁷⁵ Exhibit 20407-X0234, CCA argument, paragraphs 119-122.

⁸⁷⁶ Exhibit 20407-X0146, EDTI-AUC-JUN26-004(a).

⁸⁷⁷ Decision 3100-D01-2015, paragraph 616.

unless the driver for the project or program has changed. EPCOR confirmed that “no drivers for any of the previously approved projects or programs have changed.”⁸⁷⁸

792. For new capital tracker projects or programs proposed for 2016-2017, the Commission finds that the driver for each of EPCOR’s proposed capital tracker projects and programs, other than the AMI project discussed below, falls into one or more of the following Criterion 2 categories: asset replacement or refurbishment; required by an external party or growth related. For the reasons above, the Commission finds that EPCOR’s projects or programs presented in Table 27, other than the AMI project, satisfy the requirements of Criterion 2.

793. The UCA, in its argument, contended that the AMI project does not meet the requirements of the second capital tracker criterion because it is not a project required for the replacement of aged infrastructure that has come to the end of its useful life. According to the UCA, the conventional metering assets are not at the end of their useful life, as demonstrated by the existence of undepreciated costs associated with the conventional metering assets and as confirmed by EPCOR witnesses, who stated that the conventional meters could continue to provide for the customer revenue metering function.⁸⁷⁹ The UCA also noted EPCOR’s statement that the change in Measurement Canada rules was not the primary driver for replacing the conventional meters.

794. EPCOR’s position that the conventional meters could continue to provide for the customer revenue metering function is consistent with its position, as reflected in its prior capital tracker application, where EPCOR contended that the existing conventional meters should not be considered obsolete because they still operate and remain capable of operating in the future to provide safe and reliable utility service.⁸⁸⁰

795. In Section 6.4.2.1 of this decision, the Commission approves the need for the AMI project for purposes of capital tracker treatment. Although the conventional meters could continue to provide for the customer metering function, the least-cost alternative for dealing with anticipated escalating capital and operating costs arising from the collective age of the conventional meters and a change in Measurement Canada requirements, is to replace the conventional meters with AMI meters. Therefore, the Commission is prepared to consider the project as a replacement of existing infrastructure, thereby satisfying the requirements of Criterion 2.

9 Criterion 3 – the project must have a material effect on the company’s finances

796. Section 7 of this decision addressed EPCOR’s accounting test, which determines whether all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company’s ongoing operations, as required to satisfy Criterion 1. This is established by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project proposed for capital tracker treatment.

⁸⁷⁸ Exhibit 20407-X0146, EDTI-AUC-JUN26-004(a).

⁸⁷⁹ Exhibit 20407-X0232, UCA argument, paragraph 20.

⁸⁸⁰ Decision 3100-D01-2015, paragraph 681.

797. In accordance with the Commission's determinations in Decision 2013-435, the portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year, calculated as part of the accounting test, is then assessed against the two-tiered materiality test under Criterion 3. The first tier of the materiality threshold, a "four basis point threshold," is applied at a project level, grouped in the manner approved by the Commission. The second tier of the materiality threshold, a "40 basis point threshold," is applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.⁸⁸¹

798. In Decision 2013-435, the Commission calculated the four basis point threshold and the 40 basis point threshold based on the dollar value of EPCOR's ROE in 2012. The Commission indicated that in subsequent PBR years, the four basis point threshold and the 40 basis point threshold are to be calculated by escalating the 2012 amount by I-X.⁸⁸²

799. Further, in Decision 3100-D01-2015, the Commission determined that the calculation of the first and second tier materiality thresholds for purposes of the capital tracker true-up application for a given year, should be based on the approved I-X index for that year and directed EPCOR to follow this approach in future capital tracker true-up applications.⁸⁸³

800. For the 2014 capital tracker true up, EPCOR used the 2014 four basis point threshold of \$103,327 previously approved in Decision 3100-D01-2015,⁸⁸⁴ calculated by escalating the 2012 amount by the approved 2013 and 2014 I-X index values. Using the same methodology would result in the 40 basis point threshold of \$1.033 million for 2014. EPCOR then assessed each of the capital tracker projects included in the 2014 true-up against the four basis point threshold, in accordance with the requirements set out in paragraphs 503 to 506 of Decision 2013-435.⁸⁸⁵ EPCOR indicated that each 2014 capital tracker true-up project or program satisfies Criterion 3.

801. For the 2016 and 2017 capital tracker forecast, EPCOR calculated the materiality thresholds following the methodology set out in Decision 2013-435. However, as discussed in Section 7.1, since at the time the application was filed, EPCOR did not have the approved I factors for either 2016 or 2017, it used the I-X index value of 0.42 per cent for 2016 and negative 0.21 per cent for 2017,⁸⁸⁶ based on the approved X factor value and Dr. Ryan's inflation forecasts.⁸⁸⁷

802. EPCOR calculated the 2016 four basis point threshold of \$105,307 by escalating the 2012 amount by the approved I-X index values for 2013, 2014, and 2015, as well as the forecast I-X index value for 2016. In the same vein, EPCOR calculated the 40 basis point threshold to be \$1.053 million for 2016. Using the same methodology, EPCOR calculated the 2017 four basis point threshold to be \$105,086 and the 40 basis point threshold to be \$1.051 million.⁸⁸⁸

⁸⁸¹ Decision 2013-435, paragraphs 382-385.

⁸⁸² Decision 2013-435, paragraphs 378 and 384.

⁸⁸³ Decision 3100-D01-2015, paragraph 632.

⁸⁸⁴ Decision 3100-D01-2015, paragraph 630.

⁸⁸⁵ Exhibit 20407-X0134.02, Schedule 2, Tab 4 "1st Tier Test."

⁸⁸⁶ Exhibit 20407-X0133, Schedule 1, Tab 2, lines 116-117.

⁸⁸⁷ Exhibit 20407-X0003, Appendix E.

⁸⁸⁸ Exhibit 20407-X0130.02, revised application, paragraphs 185-190.

803. EPCOR then assessed each of the capital tracker projects or programs included in the 2016 and 2017 forecast against the four basis point threshold, and the total K factor amount associated with all capital tracker projects or programs in each of 2016 and 2017 against the 40 basis point threshold. EPCOR submitted that its proposed capital tracker projects or programs satisfy the materiality test requirement of Criterion 3.

804. No party took issue with EPCOR's calculation of its 2016 or 2017 materiality thresholds under Criterion 3.

Commission findings

805. For its 2014 true-up calculations, EPCOR used the first and second tier materiality thresholds approved in Decision 3100-D01-2015,⁸⁸⁹ based on the approved 2013 and 2014 I-X index values. For 2016 and 2017, EPCOR calculated the first and second tier materiality thresholds by escalating the respective 2012 values by the approved 2013, 2014, and 2015 I-X indexes, and then the estimated 2016 and 2017 I-X index values. As discussed in Section 7.1, given that EPCOR did not have an approved I factor for either 2016 or 2017 when it filed its application, it used 2016 and 2017 I factor estimates based on Dr. Ryan's forecasts. The Commission accepts, in principle, the use of this forecasting method given that final approved numbers were not available.

806. However, since the filing of the application, the 2016 I-X index of 0.90 per cent has been approved in Decision 20821-D01-2015.⁸⁹⁰ Consistent with the findings in Section 7.1, to minimize future true-ups, the Commission directs EPCOR, in its compliance filing to this decision, to use the approved 2016 I-X index value of 0.90 per cent to calculate the first and second tier materiality thresholds for 2016.

807. The Commission has reviewed EPCOR's calculations, and is generally satisfied that EPCOR has interpreted and applied the Criterion 3 two-tiered materiality test properly for the purposes of its 2014 true-up and 2016 and 2017 capital tracker forecasts, based on the projects and assumptions included in the application. However, as discussed earlier in this section, the two-tiered materiality test under Criterion 3 is applied to the portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year, calculated as part of the accounting test. In Section 7.3, the Commission directed EPCOR, in its compliance filing to this decision, to revise its accounting test based on approved 2014 actual and 2016 and 2017 forecast capital additions and changes to the 2016 model assumptions to reflect the approved 2016 I-X index value. Accordingly, because EPCOR's accounting test for each of 2014, 2016 and 2017 needs to be revised, the Commission cannot determine in this decision whether any of EPCOR's projects or programs proposed for capital tracker treatment in 2014 on an actual basis, and in 2016 and 2017 on a forecast basis, satisfy the materiality test requirement of Criterion 3.

808. Given these findings, the Commission directs EPCOR, in its compliance filing to this decision, to reassess whether its projects or programs proposed for capital tracker treatment in 2014 on an actual basis and in 2016 and 2017 on a forecast basis, satisfy the two-tiered

⁸⁸⁹ Decision 3100-D01-2015, paragraph 630.

⁸⁹⁰ Decision 20821-D01-2015, paragraph 23.

materiality test requirement of Criterion 3. For this reassessment, EPCOR will use the approved 2014 threshold amount, as well as revised 2016 threshold amounts, as directed above.

10 Other matters

10.1 EPCOR's compliance with Commission directions

809. In Decision 3100-D01-2015, the Commission provided a number of directions to EPCOR that were applicable to its future capital tracker applications. In Decision 3434-D01-2015 and Decision 3558-D01-2015, the Commission also provided clarifications on the capital tracker mechanism and issued a number of related directions to companies under PBR, including EPCOR.

810. EPCOR has addressed the Commission directions in the application and provided a summary table of concordance to demonstrate the compliance with the Commission's directions in Appendix F of the application,⁸⁹¹ summarized in Appendix 4 to this decision.

Commission findings

811. In previous sections of this decision, the Commission dealt with EPCOR's compliance with certain directions from Decision 3100-D01-2015, as well as Decision 3434-D01-2015 and Decision 3558-D01-2015. Specifically, in Section 5.1 of this decision, the Commission determined that EPCOR has complied with the direction from Decision 3100-D01-2015 to address the grouping of the Neighbourhood Renewal program. In that section, the Commission also noted that EPCOR has provided descriptions of capital projects or programs that were not proposed for capital tracker treatment, and thus complied with the direction from Decision 3558-D01-2015. In sections 6.1.3 and 6.1.4, respectively, the Commission found that EPCOR has complied with the directions to provide a summary of the services provided by or to an affiliate, the related costs and an explanation of how those amounts were determined, and to describe its formal project management policies and procedures. Other than as specifically mentioned in the above sections, no party challenged EPCOR's compliance with Commission directions.

812. The Commission has reviewed EPCOR's responses to the directions of the Commission not specifically addressed in the previous sections of this decision and is generally satisfied that EPCOR has complied with these directions in the application.

10.2 Additional issues raised by the CCA in its argument

813. In its argument, the CCA raised two issues not specifically addressed elsewhere in this decision. The first issue related to limiting the time period available to a utility to apply for capital tracker treatment for actual expenditures in respect of a project or program that has not been previously approved on a forecast basis. The second issue related to the reporting of information under Rule 005.⁸⁹²

⁸⁹¹ Exhibit 20407-X0002, Appendix F.

⁸⁹² Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

814. On the first issue, the CCA acknowledged that Decision 2013-435 provides that capital tracker treatment can be considered for a project on an actual expenditures basis. However, the CCA indicated it “does not believe that that was intended to be an open ended or perpetual right to go back in time.”⁸⁹³ Specifically, the CCA did not agree that EPCOR should be able to come forward in future years to apply for trackers in respect of 2013 and 2014, after the conclusion of capital tracker true-up proceedings for those years.

815. Regarding the second issue, the CCA pointed out that in its 2013 and 2014 Rule 005 reports, EPCOR calculated its ROE based on its actual, rather than approved, capital structure (also referred to as equity thickness). The CCA recommended that the Commission direct EPCOR to restate its 2013 and 2014 Rule 005 reports based on the approved equity thickness.⁸⁹⁴

Commission findings

816. With respect to the first issue raised by the CCA, the Commission observes that Decision 2012-237 does not contemplate a time limit to apply for capital tracker treatment of projects based on actual expenditures. Therefore, the Commission will assess the reasonableness of each project or program proposed for capital tracker treatment when applied for.

817. With respect to the second issue raised by the CCA, the Commission issued Bulletin 2016-03⁸⁹⁵ that clarifies certain provisions of Rule 005 requirements. The issue raised by the CCA is dealt with in that bulletin, among other matters.

11 2014 true-up and 2016-2017 forecast K factor calculations

818. In Decision 20210-D01-2015, the Commission approved the 2014 forecast K factor of \$8.83 million to be recovered from EPCOR’s customers on an interim basis.⁸⁹⁶ As part of the 2014 capital tracker true-up, EPCOR calculated its actual 2014 K factor to be \$6.62 million,⁸⁹⁷ resulting in a proposed 2014 K factor true-up adjustment of \$2.21 million to be refunded to customers, as shown in Table 1 from Section 4 of this decision. As summarized in Table 2 from Section 4 of this decision, EPCOR calculated the 2016 and 2017 forecast K factors to be \$27.57 million and \$38.16 million, respectively.⁸⁹⁸ EPCOR indicated that it calculated the proposed 2014 K factor true-up adjustment and forecast 2016 and 2017 K factors in accordance with the provisions of Decision 2013-435.⁸⁹⁹

819. EPCOR proposed to use its Rider DJ to true up the final 2014 K factor adjustment. EPCOR stated it will use the same methodology to calculate Rider DJ as was used in its 2013 capital tracker true-up rider application, approved in Decision 2014-174. Once the Commission issues a decision with regard to its proposed final 2014 capital tracker adjustment, EPCOR indicated it will file for Commission approval, a proposed Rider DJ to true up to the actual

⁸⁹³ Exhibit 20407-X0234, CCA argument, paragraph 38.

⁸⁹⁴ Exhibit 20407-X0234, CCA argument, paragraph 50.

⁸⁹⁵ Bulletin 2016-03, Clarification of Rule 005 financial reporting requirements, February 2, 2016.

⁸⁹⁶ Decision 20210-D01-2015, Table 3.

⁸⁹⁷ Exhibit 20407-X0192, paragraph 12.

⁸⁹⁸ Exhibit 20407-X0130.02, revised application, Table 1.0-1 on page 2.

⁸⁹⁹ Exhibit 20407-X0130.02, revised application, paragraphs 30 and 214.

approved amount, either as part of a compliance filing, should one be required in respect of this application, or in a separate application.⁹⁰⁰

820. Additionally, as set out in Section 4 of this decision, EPCOR identified an error relating to the treatment of vehicle depreciation in its capital tracker model. As a result of correcting this error, EPCOR calculated that the 2013 actual K factor and the 2015 forecast K factor amounts should be reduced by \$0.02 million and \$0.35 million, respectively.⁹⁰¹ Further, EPCOR identified that additional corrections were required for the years 2015 to 2017 to eliminate the double recovery of the AUF fees.⁹⁰² EPCOR proposed to true up the differences for 2013, 2014, 2016 and 2017 in the compliance filing to this decision or as directed by the Commission. EPCOR proposed to true up the differences for 2015 in its 2015 capital tracker true-up application.

821. Regarding the recovery of the approved 2016 and 2017 forecast K factor amounts, EPCOR proposed to use the simplified approach, approved in Decision 2013-072, to allocate these amounts to customer classes and calculate the associated K factor adjustment rates. Under this approach, the approved forecast K factor amounts will be allocated to customer classes using the percentage of base revenue as an allocator. As a next step, the K factor rate will be calculated for each rate class by dividing the allocated rate class amount by the relevant billing determinants for that rate class.

822. In this regard, EPCOR noted that final base rates and final billing determinants are approved as part of the annual PBR rate adjustment filings each year. As such, EPCOR stated it would provide the calculation of its capital tracker factor allocator percentages and corresponding 2016 K factor adjustment rates in its 2016 annual PBR rate adjustment filing due on September 10, 2015. Similarly, EPCOR indicated it would provide the calculation of its capital tracker factor allocator percentages and corresponding 2017 K factor adjustment rates in its 2017 annual PBR rate adjustment filing due September 10, 2016.⁹⁰³

Commission findings

823. In Section 6, the Commission confirmed the prudence of actual capital additions associated with EPCOR's projects or programs included in the 2014 capital tracker true-up, with the exception of the Customer Revenue Metering – Growth & Life Cycle Replacements project. However, these approvals were subject to removing the portion of costs associated with capitalized STIP amounts and reflecting the actual negotiated salary escalation rates for EPCOR's unionized employees. Additionally, EPCOR identified a referencing error affecting the 2014 actual K factor calculations and stated it will correct this error in the compliance filing.⁹⁰⁴ Because these revisions will result in changes to the 2014 actual K factor amount, the Commission cannot approve a final 2014 K factor true-up adjustment for EPCOR in this decision.

824. In a similar vein, with the exception of the Life Cycle Replacement and Extension of Underground Distribution Cable and the Customer Revenue Metering – Growth & Life Cycle

⁹⁰⁰ Exhibit 20407-X0130, application, paragraph 1115.

⁹⁰¹ Exhibit 20407-X0146, EDTI-AUC-JUN26-031, Table EDTI-AUC-JUN26-031-1.

⁹⁰² Exhibit 20407-X0130.01, paragraphs 5 and 7.

⁹⁰³ Exhibit 20407-X0130.02, revised application, paragraphs 1111-1114.

⁹⁰⁴ Exhibit 20407-X0192, paragraphs 11-12.

Replacements project, the Commission determined that EPCOR's forecast capital expenditures for the proposed 2016 and 2017 capital tracker projects or programs were generally reasonable, subject to removing the capitalized STIP costs, adjusting certain labour escalation factors and recalculating the capital overhead amounts allocated to capital tracker projects or programs. In sections 7.3 and 9, the Commission directed EPCOR, in its compliance filing to this decision, to revise its accounting test assessment under Criterion 1 and the two-tiered materiality test assessment under Criterion 3 for 2016. Because these revisions will result in changes to the 2016 and 2017 forecast K factor amounts, the Commission cannot approve 2016 or 2017 K factor adjustments for EPCOR, on a forecast basis, in this decision.

825. Nevertheless, the Commission has reviewed EPCOR's calculations and finds that EPCOR's methodology to determine the 2014 K factor true-up amount and the 2016 and 2017 K factor forecast amounts is generally consistent with the requirements set out in Decision 2012-237 and Decision 2013-435.

826. In Decision 2013-462, the Commission approved a K factor placeholder of \$6.08 million, representing some 60 per cent of the applied-for amount, to be included in EPCOR's 2014 PBR rates.⁹⁰⁵ As set out in Decision 20559-D01-2015, to avoid an unnecessary collection followed by an expected refund, EPCOR proposed to true up the difference between the 2014 K factor placeholder and the 2014 actual K factor amount, once the final amount is approved by the Commission in the present proceeding. The Commission accepted this proposal.⁹⁰⁶ Consistent with the approach used in prior capital tracker applications approved by the Commission, EPCOR will collect the difference between the approved 2014 K factor placeholder and the 2014 actual K factor amount, approved in the decision on the compliance filing to this decision, using its existing Rider DJ mechanism.

827. In addition to collecting the 2014 K factor true-up amount, the Commission considers that EPCOR should also deal with any identified corrections to the 2013 actual K factor amount,⁹⁰⁷ and the difference between the 2016 K factor placeholder and the approved 2016 K factor forecast, using the same Rider DJ. Therefore, rather than including the Rider DJ rate in its compliance filing to this decision, the Commission directs EPCOR to file a separate application for the combined Rider DJ rate, that includes the identified correction to the 2013 actual K factor amount, the difference between the approved 2014 K factor placeholder and the 2014 actual K factor amount, and the reconciliation between the 2016 K factor placeholder and the 2016 forecast K factor, after they are approved by the Commission in the compliance filing decision. The effective date and the duration of the new collection period for the combined Rider DJ should be commensurate with the Commission's process timelines set out in Bulletin 2015-09 and take into account the impact on customer bills.

828. In Decision 20210-D01-2015 dealing with EPCOR's compliance filing to Decision 3100-D01-2015, the Commission approved a forecast 2015 K factor amount of \$17.18 million. In this proceeding, EPCOR identified a number of corrections to that amount, arising from the errors in vehicle depreciation and treatment of the AUF fees, totalling some \$0.7 million.⁹⁰⁸ Given that

⁹⁰⁵ Decision 2013-462, paragraphs 47, 57 and 58.

⁹⁰⁶ Decision 20559-D01-2015, paragraph 14.

⁹⁰⁷ Exhibit 20407-X0146, EDTI-AUC-JUN26-031, Table EDTI-AUC-JUN26-031-1.

⁹⁰⁸ Exhibit 20407-X0146, EDTI-AUC-JUN26-031, Table EDTI-AUC-JUN26-031-1 and Exhibit 20407-X0130.01, paragraph 7.

these corrections are relatively small, the Commission agrees with EPCOR's view that it will be more efficient to deal with any corrections to the 2015 K factor amounts as part of the 2015 K factor true-up.

12 Order

829. It is hereby ordered that:

- (1) EPCOR Distribution & Transmission Inc. is directed to file a compliance filing application in accordance with the directions contained within this decision on or before March 16, 2016.

Dated on February 7, 2016.

Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Henry van Egteren
Commission Member

(original signed by)

Neil Jamieson
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI)
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP

Alberta Utilities Commission Commission Panel M. Kolesar, Vice-Chair H. van Egteren, Commission Member N. Jamieson, Commission Member Commission Staff B. McNulty (Associate General Counsel) L. Desaulniers (Commission counsel) O. Vasetsky J. Work A. Corsi E. Deryabina J. Bezuidenhout

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo D. Both	<u>Panel 1</u> R. McNeil K. Hull S. Chaudhary J. Baraniecki R. Reimer G. Zurek <u>Panel 2</u> J. Baraniecki S. Chaudhary R. Reimer L. Kennedy <u>Panel 3</u> W. Snyder D. Spare K. Hull
Office of the Utilities Consumer Advocate (UCA) T. D. Marriott, QC A. Preda	R. Bell B. Shymanski
Consumers' Coalition of Alberta (CCA) J. A. Wachowich S. Gibbons	J. Thygesen

Alberta Utilities Commission Commission Panel M. Kolesar, Vice-Chair H. van Egteren, Commission Member N. Jamieson, Commission Member Commission Staff B. McNulty (Associate General Counsel) L. Desaulniers (Commission counsel) O. Vasetsky J. Work A. Corsi E. Deryabina

Appendix 3 – Summary of Commission directions

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

1. In the application, and throughout the record in this proceeding, these two projects were addressed separately. For ease of reference and for better clarity, the Commission will address these two projects separately in this decision. However, in its compliance filing to this decision and in future capital tracker applications, the Commission directs EPCOR to group these two projects together under a “Customer Revenue Metering” program, while filing separate business cases for the purpose of project assessment and retaining two different line entries in the accounting test model for these two grouped projects. This is similar to the approach that EPCOR currently uses for its Third-Party Driven Relocations program. Paragraph 67
2. Given the Commission’s findings regarding the three non-capital tracker projects and the Work Centre Redevelopment project, the Commission directs EPCOR to include all four projects (Work Centre Redevelopment project, North and South Service Centre Building Life Cycle Replacements project, Service Centre Consolidation project and the Furniture Life Cycle replacement project) in a single group for the purposes of capital tracker analysis in its compliance filing to this decision, as provided by EPCOR in Table 3. Similar to the directions in Section 5.2.1 above, while grouping these projects into a single program, EPCOR should continue filing separate business cases for the purpose of project assessment and showing different line entries in the accounting test model for these projects, as shown in Table 3. This is similar to an approach that EPCOR currently uses for its Third-Party Driven Relocations program. Paragraph 90
3. Given that both the DAM – Distribution Manhole Rebuilds project and the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes projects consist of life cycle replacements of structural components of manholes and that downtown work crews are able to undertake the required work for either project, the Commission considers that the DAM – Distribution Manhole Rebuilds project and the Rebuild and/or Replace Civil Work for Downtown Vault and Manholes capital tracker project are sufficiently similar in nature, and have drivers that are sufficiently related to warrant being grouped together for capital tracker purposes. EPCOR is directed to group these projects together in the compliance filing to this decision. Paragraph 104
4. Evidence in this proceeding suggests that salary escalation rates are on a downward trend. EPCOR indicated that, subsequent to proposing the Conference Board of Canada rates of 3.1 per cent and 3.2 per cent used in its 2015-2017 TFO application, the 3.0 per cent escalation factor included in the present application for EPCOR’s unionized employees, was provided by EPCOR Utilities Inc. to all EPCOR business units in January 2015 for use in preparation of their 2016 budgets. As well, the actual 2014 to 2017 negotiated salary escalation rates for EPCOR’s CSU employees, clearly demonstrate the downward trend for unionized employees, as further discussed below. In light of these trends, the Commission does not accept EPCOR’s recommendation to use rates at the high end of the Towers Watson report for non-unionized employees. The Commission considers an escalation rate of 3.0 per cent, which is at the lower range of the recommendation in the

- Towers Watson report, to be reasonable for the purposes of determining the non-union labour cost associated with proposed capital tracker expenditures for 2016 and 2017. The Commission directs EPCOR to reflect these non-union employee escalation rates in its compliance filing application to this decision. Paragraph 132
5. As noted above, evidence in this proceeding suggests that salary escalation rates are on a downward trend as most recently demonstrated by the collective bargaining agreement negotiated by EPCOR with the CSU union workers for 2014 to 2017. The CSU agreement sets out a range of increases dependent on employee classification, ranging from 3.50 to 4.00 per cent in 2014, from 2.25 to 2.50 per cent in 2016, and from 2.15 to 2.40 per cent in 2017. The Commission directs EPCOR to reflect the 2016 and 2017 ratified collective agreement CSU employee escalation rates in the compliance filing to this decision. In light of the downward trend in salary escalation rates, the Commission considers that an escalation rate of 2.5 per cent for IBEW unionized labour is reasonable for purposes of the accounting test to be used in forecasting 2016 and 2017 capital trackers. The Commission directs EPCOR to reflect the 2.5 per cent labour escalation rate for the IBEW unionized workers in the compliance filing to this decision. . Paragraph 134
 6. Additionally, the Commission directs EPCOR, in its compliance filing to this decision, to account for the actual 2014 escalation rate for CSU and IBEW union workers under their respective collective bargaining agreements in the 2014 capital tracker true-up. In the compliance filing to this decision, EPCOR is also directed to explain the adjustments it has made to the 2014 capital tracker true-up, to account for the actual 2014 escalation rates as per its collective bargaining agreements. Paragraph 135
 7. Consistent with its determinations on the escalation rates for the non-union employees, the Commission directs EPCOR to limit the increase in contractor costs to three per cent in each of 2016 and 2017. The Commission finds the escalation rates for other costs of 2.1 per cent and 2.0 per cent, for 2016 and 2017, respectively, and the materials escalation rates of 2.2 per cent for both years proposed by EPCOR to be reasonable. Paragraph 137
 8. Finally, regarding the escalation factors, the Commission observes that EPCOR forecast capital expenditures for a number of projects (listed in EDTI-AUC-2015JUN26-014) using its three-year normalized historical actual average costs methodology that relies on certain escalation factors, including labour, materials, contractors, vehicles and equipment as set out in Table 2.2-5 of the application. In the Commission's view, the escalation factors used in this table for the purposes of forecasting expenditures for capital tracker projects that rely on the normalized methodology should be consistent with the escalation factors used in the balance of the application for other capital tracker projects. Therefore, in its compliance filing to this decision, EPCOR is directed to provide an updated Table 2.2-5 reflecting the escalation factors consistent with the Commission's approvals above, and to explain how it recalculated the resulting forecast 2016 and 2017 capital expenditures for (i) projects that used the normalized methodology, as compared to (ii) the remaining projects employing forecasts based on EPCOR's bottom-up approach. Paragraph 138
 9. The Commission directs EPCOR, in its compliance filing to this decision, to recalculate the capital overhead amounts included in the forecast capital expenditures for its 2016 and 2017 capital tracker projects, based on the capital overhead forecast calculated by applying the approved I-X indexes for 2015 and 2016 and EPCOR's estimate for the

- 2017 I-X index used in the accounting test (discussed in Section 7.1) to the 2014 actual capital overhead amounts. The obtained capital overhead amounts can then be allocated to EPCOR's capital tracker and non-capital tracker projects, consistent with the company's capitalization and allocation methodologies, provided that EPCOR will retain the existing distinction in capital overhead allocation for the "1 per cent projects," (the Work Centre Redevelopment and the AMI projects) from other capital projects. In doing so, EPCOR should also remove from the 2014 actual and 2016 and 2017 forecast capital overhead amounts any capitalized STIP amounts, as directed in Section 6.1.2 of this decision. Paragraph 144
10. The Commission considers that in the circumstances where a company is not certain whether the provisions of paragraph 862 of Decision 2012-237 apply to a contemplated change to accounting methods, the company should err on the side of caution and make a disclosure in its senior officer attestation as part of the annual PBR rate adjustment filing regardless of whether the change represents "a change in accounting policy" or a change in accounting practice, even when the change is to effect "the application of EDTI's existing Commission-approved capitalization policy to STIP costs." The Commission directs EPCOR to follow this approach in its future applications related to PBR and capital trackers. Paragraph 169
11. The Commission recognizes that the proposed capitalization of STIP appears to be consistent with acceptable accounting practices under IFRS. However, as set out in paragraph 594 of Decision 2012-237, in order for a capital cost to qualify for capital tracker treatment, the company must demonstrate that there is no double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded through the I-X mechanism. Accordingly, having made the finding that double counting of a portion of STIP Pool A costs would occur, the Commission denies the inclusion of capitalized STIP in the costs of EPCOR's proposed capital tracker projects in the current PBR term. EPCOR is directed, in the compliance filing to this decision, to remove any capitalized STIP costs from the 2014 actual and 2016 and 2017 forecast capital expenditures associated with the projects or programs proposed for capital tracker treatment. Paragraph 177
12. The Commission agrees with the concerns raised by the CCA with respect to double counting of inspection costs in respect of the 2016 and 2017 years and accepts the CCA's recommendation to deny the inclusion of capitalized inspection costs related to the installation of new meters and service connections in the costs of the Customer Revenue Metering – Growth & Life Cycle Replacements project on a go-forward basis for 2016 and 2017. EPCOR is directed, in the compliance filing to this decision, to remove any capitalized inspection costs related to the installation of new meters and service connections costs from the 2016 and 2017 forecast capital expenditures associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project. Paragraph 180
13. The Commission has reviewed EPCOR's project management controls and accountability policies and procedures in light of the directions set out at paragraph 152 of Decision 3100-D01-2015. EPCOR provided a helpful explanation of its controls and accountability procedures with respect to the planning, design, execution and review of its capital projects, in order to aid in the Commission's understanding of whether the scope, level, timing and costs of forecast capital projects are reasonable and the actual

- costs are prudently incurred. The Commission finds that EPCOR has complied with the direction set out at paragraph 152 of Decision 3100-D01-2015. The Commission directs EPCOR to confirm that these policies and procedures continue to be in place and to advise the Commission of improvements and modifications to these policies and procedures in future capital tracker applications. Paragraph 217
14. Because the AUF amounts do not represent a reduction to capital rate base, but instead, are an offset to a project's capital costs included in rates, the Commission understands EPCOR's hesitation to include the new AUFs in the capital additions part of its accounting test schedules. The Commission does, however, see merit in having the new AUFs included in another part of EPCOR's accounting test schedules (for example, dealing with the K factor calculation) because all the relevant K factor information will be set out in a single location, leading to better transparency in EPCOR's capital tracker applications. Accordingly, EPCOR is directed, in its future capital tracker applications, starting with the compliance filing to this decision, to include its new AUFs for the Work Centre Redevelopment project and the OMS/DMS project (and in the future, for any other capital tracker projects or programs to which new AUFs apply) in its accounting test schedules in a manner that demonstrates the amount of the AUF offset. In its compliance filing to this decision, EPCOR is also directed to explain its preferred approach to including the new AUFs in the accounting test schedules. Paragraph 240
 15. The Commission expects that in EPCOR's capital tracker true-up applications, it will offset the K factors, based on actual capital additions, for the projects discussed above by the AUF amounts calculated on the basis of actual capital additions. EPCOR is directed in its future capital tracker true-up applications, to include a table outlining the variance in AUFs between forecast and actual amounts, as well as the actual K factor amounts before and after the AUF is applied. Paragraph 241
 16. In Section 6.1 of this decision, the Commission directed certain adjustments applicable to all projects and programs proposed for capital tracker treatment, such as an adjustment to certain labour escalation rates and allocated capital overhead amounts, including capitalized STIP amounts. Accordingly, the Commission directs EPCOR, in its compliance filing to this decision, to revise its forecast for 2016 and 2017 capital additions for this project using a three-year average of \$9.7 million, adjusted for 2016 and 2017 using the labour escalation rates and allocated capital overhead amounts approved in Section 6.1, and reflect these revised forecast capital additions in its 2016 and 2017 forecast K factor calculation. The Commission also directs EPCOR to explain the methodology used to determine the 2016 and 2017 capital additions for this project, based on the three-year average of \$9.7 million, and escalation factors approved in Section 6.1..... Paragraph 290
 17. Based on the record of this proceeding, it is unclear if the increase in corporate cost allocations associated with EPCOR no longer renting space at EPCOR Tower from its parent company will have an effect on EPCOR's Work Centre Redevelopment project capital tracker and K factor calculation. EPCOR is directed, in its 2015 capital tracker true-up application, to explain this matter and to identify clearly any increased corporate costs associated with EPCOR no longer renting space at EPCOR Tower, allocated to any capital tracker project. Paragraph 466
 18. The Commission directs EPCOR, in its compliance filing to this decision, to explain the extent to which its 2014 actual costs for the Customer Revenue Metering – Growth &

- Life Cycle Replacements project were affected by its decision to proceed with the AMI project, including any effect of Measurement Canada's dispensation. Additionally, EPCOR is directed to explain, in the compliance filing, with supporting documentation, the terms of the Measurement Canada dispensation including timing and scope (i.e., type and number of meters subject to the obtained dispensation). Paragraph 563
19. For all of the above reasons, the Commission finds that determinations in paragraph 688 of Decision 2012-237 also apply to K factors. Accordingly, given that EPCOR's accelerated depreciation proposal is contrary to the Commission's determinations at paragraph 688 of Decision 2012-237, EPCOR's application to change existing depreciation rates on conventional meters and to recover the accelerated depreciation through the K factor calculation associated with the Customer Revenue Metering – Growth & Life Cycle Replacements project is denied. In the compliance filing to this decision, EPCOR is directed to remove the accelerated depreciation amounts from the K factor calculation and base its revenue requirement calculation associated with this project on the amounts reflective of the depreciation rates approved in Decision 2012 272. Paragraph 616
 20. Regarding the 2016 forecast, the Commission observes that, since the filing of the application, the 2016 I-X index of 0.90 per cent and billing determinants forecast were approved in Decision 20821-D01-2015. To minimize future true-ups, the Commission directs EPCOR, in its compliance filing to this decision, to use the approved 2016 I-X index value and the Q factor based on the forecast billing determinants approved in Decision 20821-D01-2015 for purposes of its 2016 capital tracker forecast accounting test. Paragraph 750
 21. The Commission directs EPCOR, in its compliance filing to this decision, to revise its accounting test for 2014, as well as for 2016 and 2017, based on approved final forecast or actual capital additions, the 2016 model assumptions and other directions as set out in the previous sections of this decision. EPCOR is further directed to provide two summary tables in the compliance filing to this decision. The first table will include for each capital tracker project or program, a comparison of the 2014 actual capital additions applied for in this proceeding and the 2014 actual capital additions, revised in accordance with the directions set out in this decision. The second table will provide a similar comparison for the forecast 2016 and 2017 capital trackers. Paragraph 778
 22. However, since the filing of the application, the 2016 I-X index of 0.90 per cent has been approved in Decision 20821-D01-2015. Consistent with the findings in Section 7.1, to minimize future true-ups, the Commission directs EPCOR, in its compliance filing to this decision, to use the approved 2016 I-X index value of 0.90 per cent to calculate the first and second tier materiality thresholds for 2016. Paragraph 806
 23. Given these findings, the Commission directs EPCOR, in its compliance filing to this decision, to reassess whether its projects or programs proposed for capital tracker treatment in 2014 on an actual basis and in 2016 and 2017 on a forecast basis, satisfy the two-tiered materiality test requirement of Criterion 3. For this reassessment, EPCOR will use the approved 2014 threshold amount, as well as revised 2016 threshold amounts, as directed above. Paragraph 808
 24. In addition to collecting the 2014 K factor true-up amount, the Commission considers that EPCOR should also deal with any identified corrections to the 2013 actual K factor amount, and the difference between the 2016 K factor placeholder and the approved 2016

K factor forecast, using the same Rider DJ. Therefore, rather than including the Rider DJ rate in its compliance filing to this decision, the Commission directs EPCOR to file a separate application for the combined Rider DJ rate, that includes the identified correction to the 2013 actual K factor amount, the difference between the approved 2014 K factor placeholder and the 2014 actual K factor amount, and the reconciliation between the 2016 K factor placeholder and the 2016 forecast K factor, after they are approved by the Commission in the compliance filing decision. The effective date and the duration of the new collection period for the combined Rider DJ should be commensurate with the Commission's process timelines set out in Bulletin 2015-09 and take into account the impact on customer bills. Paragraph 827

25. (1) EPCOR Distribution & Transmission Inc. is directed to file a compliance filing application in accordance with the directions contained within this decision on or before March 16, 2016. Paragraph 829

Appendix 4 – EPCOR’s compliance with prior Commission directions

	Decision reference	Direction	Application reference Exhibit 20407- X0130.02
1	Decision 3100-D01-2015, paragraph 78	The Commission considered that it may be warranted to group all of EDTI’s life cycle replacement and like projects together with the Neighbourhood Renewal program for the purposes of the accounting test, given that it appears these projects are all intended to replace or renew aging assets. Accordingly, EDTI was directed to explain, in its next capital tracker application, whether it is possible to do so and whether such grouping is warranted.	Section 2.1.2
2	Decision 3100-D01-2015, paragraph 152	The Commission considered that formal project management policies and procedures are necessary to ensure the Commission understands that the scope, level, timing and costs of forecast capital projects are reasonable and actual costs are prudently incurred. The Commission directed EDTI to describe fully its formal project management policies and procedures in its next capital tracker application.	Section 2.1.4
3	Decision 3100-D01-2015, paragraph 578	EDTI calculated the 2013 Q factor of 0.54 per cent based on the preliminary forecast of 2013 billing determinants approved in Decision 2013-072. In its compliance filing to Decision 3100-D01-2015, the Commission directed EDTI to use the 2013 Q factor of 1.46 per cent based on the final forecast billing determinants approved in Decision 2013-270, for the 2013 capital tracker true-up accounting test. Similarly, in its future capital tracker true-up applications, the Commission directed EDTI to utilize the approved I-X index and the Q factor based on a final approved billing determinants forecast for that year in the accounting test.	Section 2.7
4	Decision 3100-D01-2015, paragraph 616	In subsequent capital tracker true-up applications, the Commission directed EDTI to address whether the driver for any of the previously approved forecast projects or programs has changed, so as to warrant a reassessment under Criterion 2. In the event that the driver of the project or program has changed since the forecast project or program was approved, EDTI was directed to identify such projects and programs and to provide	Appendix A

	Decision reference	Direction	Application reference Exhibit 20407-X0130.02
		evidentiary support that each project or program continues to satisfy the requirements of Criterion 2.	
5	Decision 3100-D01-2015, paragraph 632	The Commission considered that the calculation of the first and second tier materiality thresholds for purposes of the capital tracker true-up application for a given year should be based on the approved I-X index for that year. The Commission directed EDTI to follow this approach in future capital tracker true-up applications.	Section 2.7, Section 4
6	Decision 3434-D01-2015, paragraph 70	The Commission acknowledged that all parties in the proceeding leading to Decision 3434-D01-2015 agreed that the ROE and capital structure should be updated for the purposes of the revenue requirement calculation in the second component of the accounting test to reflect the outcomes of Proceeding 2191. This is consistent with the Commission's findings set out in paragraph 977 of Decision 2012-237. Accordingly, the Commission directed the companies to update the ROE and capital structure used in the second component of the accounting test to reflect the approved values resulting from the Proceeding 2191. This was to include all changes to the ROE and capital structure that are directed in the decision in Proceeding 2191 and not just those that are directly made to account for the change in risk profile that may have resulted from the transition to PBR. Furthermore, the Commission considered that in the second component of the accounting test, it is necessary to update the ROE to incorporate the most recently approved ROE, and those values will continue to be updated in future GCOC proceedings. Similar to the ROE, the Commission considered that the capital structure also should be revised in the second component of the accounting test to match decisions made in future GCOC proceedings. To the extent there is a time lag between when capital tracker decisions are released and when the decisions on future GCOC proceedings for the same year are released, similar to the current situation, where	Section 2.7

	Decision reference	Direction	Application reference Exhibit 20407- X0130.02
		the Commission has issued some decisions on 2013 capital tracker true-up applications but the ROE and capital structure for 2013 have not yet be finalized in the decision in Proceeding 2191, all capital tracker amounts will remain interim until the ROE and capital structure have been finalized by the Commission for the year in question.	
7	Decision 3434-D01-2015, paragraph 76	The Commission considered that using the forecast cost of embedded debt and preferred shares for the year in which the capital tracker is being applied for is a reasonable method of matching capital tracker revenues to costs. As such, the Commission directed the companies in their 2016 and 2017 capital tracker applications to use their forecast cost of embedded debt and preferred shares, if applicable, when calculating the revenue requirement associated with a proposed capital tracker. The companies are not required to update the debt rates used in their 2014 and 2015 forecast capital tracker applications because these will eventually be trued-up to actual, and a revised forecast is not required to ensure that the final rates will eventually reflect the correct debt rates.	Section 2.3
8	Decision 3434-D01-2015, paragraph 89	In Section 3.2 of Decision 3434-D01-2015, the Commission directed the companies to use their forecast cost of embedded debt in calculating the forecast revenue requirement associated with a proposed capital tracker in the second component of the accounting test, to reflect the correct funding requirements associated with expenditures made on capital tracker projects. Similarly, the Commission found that the forecast cost of embedded debt should be trued-up to the actual cost of embedded debt incurred by the utility in the year for which the capital tracker was approved. The Commission agreed with Calgary that the embedded debt rate used in the second component of the accounting test in the true-up process should match the rate that appears on the company's Rule 005 filing from the associated year, and if it does not match, the Commission directed the company to provide an explanation of why it does not match, in its	Section 2.7

	Decision reference	Direction	Application reference Exhibit 20407-X0130.02
		capital tracker true-up application.	
9	Decision 3434-D01-2015, paragraph 92	The Commission directed that in capital tracker true-up applications, for the second component of the accounting test, a company's WACC will reflect the company's current embedded debt rate based on its actual debt issues, and will use the ROE and capital structure for the year, as approved in the most recent Commission decision establishing the deemed ROE and capital structure for the company.	Section 2.7.2
10	Decision 3558-D01-2015, paragraph 44	The Commission directed the companies in their future capital tracker applications, starting with the 2014 true-up and 2016-2017 forecast capital tracker applications, to provide, in Excel format with linked and working formulas, the actual and forecast capital additions for all projects and programs, including both capital tracker and non-capital tracker capital projects and programs. Companies were also directed to provide supporting calculations for any component of capital additions or capital-related revenue requirement that involves the allocation of an aggregated amount of dollars among projects and programs showing how the allocations were performed, including a breakdown of the amount of depreciation, overheads and income tax allocated to each capital tracker project and program and non-capital tracker project and program reconciled to the total amount of depreciation, overheads and income tax for all projects and programs. The Commission has added this requirement to its revised minimum filing requirements in Appendix 3.	Schedules 1 to 4
11	Decision 3558-D01-2015, paragraph 50	The Commission considered that a short description outlining the nature, scope and timing of non-capital tracker projects and programs will be of assistance in understanding the proposed grouping of capital projects and programs for capital tracker treatment. A requirement for a limited description should not be unduly onerous and may reduce the need for information requests from the Commission and parties. Accordingly, the companies were directed in their future capital tracker	Section 2.1.6

	Decision reference	Direction	Application reference Exhibit 20407-X0130.02
		applications, starting with the 2014 true-up and 2016-2017 forecast applications, to provide descriptions of the types of capital for non-capital tracker projects or programs. The Commission has added this requirement to its revised minimum filing requirements in Appendix 3.	
12	Decision 3558-D01-2015, paragraph 80	The Commission considered the application of all the criteria in Section 30 of the Minimum Filing Requirements approved in Bulletin 2006-025 to overhead or other services provided by affiliates that are included in capital tracker costs to be unnecessary detail. However, the Commission found merit in the separate identification of any affiliate related costs included in the actual or forecast costs of a project or program for which a company is seeking capital tracker treatment. Accordingly, the companies were directed to include in their business cases a summary of the services provided by or to an affiliate, the related costs and an explanation of how those amounts were determined. This requirement has been included in the Commission's revised minimum filing requirements in Appendix 3.	Section 2.1.5



ATCO Electric Ltd.

2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast

March 3, 2016

Alberta Utilities Commission

Decision 20555-D01-2016

ATCO Electric Ltd.

2014 PBR Capital Tracker True-Up and
2016-2017 PBR Capital Tracker Forecast
Proceeding 20555

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1 Introduction

1. On June 19, 2015, ATCO Electric Ltd. (ATCO Electric or AE) filed an application with the Alberta Utilities Commission requesting approval of its 2014 capital tracker true-up and 2016-2017 capital tracker forecast under performance-based regulation (PBR).
2. On June 22, 2015, the Commission issued a notice of application that required interested parties to submit a statement of intent to participate (SIP) by June 29, 2015. In their SIPs, parties were to provide a description of their interest in the proceeding, an explanation of their position and submissions as to process. The Commission received SIPs from the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA).
3. After reviewing the application and the SIPs, the Commission determined that the application would be considered by way of a *full-process* proceeding, as described in Bulletin 2015-09,¹ and established a schedule for the proceeding as set out in the table below.

Process step	Deadline dates
Information requests (IRs) to ATCO Electric	July 20, 2015
IR responses from ATCO Electric	August 10, 2015
Intervener evidence	August 31, 2015
IRs to interveners	September 14, 2015
IR responses from interveners	September 28, 2015
Rebuttal evidence	October 13, 2015
Oral hearing	October 26 to November 6, 2015
Argument	November 20, 2015
Reply argument	December 4, 2015

4. On August 10, 2015, ATCO Electric revised its accounting test schedules, originally included as Appendix A to the application,² to reflect corrections made as a result of discovering certain errors in the course of preparing IR responses.³

¹ Bulletin 2015-09, Performance standards for processing rate-related applications, March 26, 2015.

² Exhibit 20555-X0007, PDF pages 89-120 and Exhibit 20555-X0006.

³ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a), Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules).

5. In a letter dated October 22, 2015,⁴ after consideration of the information received by the parties regarding their preliminary estimates of the time required for cross-examination and the Commission's own informational requirements, the Commission indicated its expectation that the oral hearing would commence on October 26, 2015, as originally scheduled but that it was likely to conclude by October 30, 2015.

6. At the oral hearing, the Commission confirmed that the argument and reply argument dates would remain as originally established.⁵

7. In a letter dated December 3, 2015,⁶ the Commission denied a request from the UCA to suspend the process schedule and add process steps, in light of certain press releases reporting employee layoffs by the ATCO Group in the latter half of November 2015.

8. The Commission considers the record for this proceeding to have closed on December 4, 2015, when reply arguments were filed.

9. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, as well as findings in Decision 2012-237,⁷ Decision 2013-435,⁸ Decision 3218-D01-2015,⁹ and related compliance decisions. Accordingly, references in this decision to specific parts of the records 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 records with respect to a particular matter.

2 Background

2.1 Overview of the capital tracker approach under PBR

10. On September 12, 2012, the Commission issued Decision 2012-237, approving PBR plans for the distribution utility services of certain Alberta electric and gas companies (collectively the distribution utilities), including ATCO Electric. The PBR plans were approved for a five-year term commencing January 1, 2013. PBR replaces traditional cost of service regulation as the annual rate-setting mechanism for distribution utility rates.

11. As set out in Decision 2012-237, the PBR framework provides a formula mechanism for the annual adjustment of rates for those companies under an approved PBR plan. In general, the rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation (I) which is relevant to the prices of inputs the companies use, less an offset (X) to reflect the productivity improvements the company can be expected to achieve during the PBR plan period. As a result, with the exception of specifically approved adjustments, a utility's revenues are no

⁴ Exhibit 20555-X0048.

⁵ Transcript, Volume 4, page 707, lines 1-5.

⁶ Exhibit 20555-X0079.

⁷ Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

⁸ Decision 2013-435: Distribution Performance-Based Regulation 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

⁹ Decision 3218-D01-2015: ATCO Electric Ltd., 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast, Proceeding 321, Application 1610569-1, March 15, 2015.

longer linked to its costs. Companies subject to a PBR regime must manage their businesses and service obligations with the revenues derived under the PBR indexing mechanism and adjustments provided for in the formula. The PBR framework is intended to provide incentives for productivity increases and cost savings similar to those operating in competitive markets.

12. A company may apply for approval of certain rate adjustments to enable the recovery of specific costs where it can be demonstrated that the costs cannot be recovered under the I-X mechanism and where certain other criteria have been satisfied. These possible adjustments include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (a Y factor), and an adjustment to account for the effect of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan (a Z factor). In addition, the Commission determined that a rate adjustment mechanism to fund certain capital-related costs may be required under the approved PBR plans.¹⁰ This supplemental funding mechanism was referred to in Decision 2012-237 as a “capital tracker” with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a “K factor” adjustment to the annual PBR rate-setting formula.

13. At paragraph 592 of Decision 2012-237, the Commission set out three criteria that any capital project or program would have to satisfy in order to receive capital tracker treatment:

- (1) The project must be outside of the normal course of the company’s ongoing operations.
- (2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
- (3) The project must have a material effect on the company’s finances.

14. Further, at paragraph 593 of Decision 2012-237, the Commission indicated that the party recommending the capital tracker must demonstrate that all of the criteria have been satisfied in order for a capital project or program to receive consideration as a capital tracker.

15. The implementation and application of the above capital tracker criteria were considered in the 2013 capital trackers proceeding, leading to Decision 2013-435. The Commission indicated that the implementation methodology established in that decision would be used not only to evaluate the capital tracker projects or programs proposed by the parties for 2013, but also for subsequent capital tracker applications throughout the PBR term.¹¹

16. With respect to the first capital tracker criterion, the Commission concluded that, in general, in order for a capital project or program to be considered outside of the normal course of the company’s ongoing operations, the utility would need to demonstrate that the revenue provided under the I-X mechanism in respect of that project or program would be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program. Accordingly, the Commission found that the concept of normal course is mainly a financial and accounting consideration, rather than strictly an engineering consideration. The Commission referred to this comparison of revenues as the “accounting test” component of Criterion 1. In addition, the Commission indicated the utility must demonstrate

¹⁰ Decision 2012-237, paragraph 586.

¹¹ Decision 2013-435, paragraph 120.

that a project or program proposed for capital tracker treatment is (i) required to provide utility service at adequate levels (also referred to as a need assessment) and, if so, (ii) the scope, level and timing of the project are prudent, and the forecast or actual costs of the project or program are reasonable. The Commission referred to this as the “project assessment” component of Criterion 1. Both the accounting test component and the project assessment component must be satisfied in order for a capital project or program to satisfy the requirements of Criterion 1.¹²

17. Regarding the accounting test component of Criterion 1, the Commission determined that this test should be based on the project net cost approach adopted in Decision 2013-435. Under this methodology, the revenue generated under the I-X mechanism for each capital project (or capital program or project category) is compared to the forecast revenue requirement associated with that capital project (or capital program or project category) in a PBR year. No consideration of operating and maintenance (O&M) costs or savings and potential productivity offsets above those implied by the approved X factor is required for the accounting test. The Commission provided further guidance on the weighted average cost of capital (WACC) rate assumptions of the accounting test in Decision 3434-D01-2015.¹³

18. For purposes of the project assessment, the Commission determined that each project or program proposed for capital tracker treatment must generally be supported by a business case and an engineering study. However, the Commission recognized that in some circumstances, an engineering study may not be required. In Decision 2013-435, the Commission set out certain minimum filing requirements that a project or program proposed for capital tracker treatment should typically address in order to assist the Commission’s project assessment.¹⁴ These minimum filing requirements were subsequently refined in Decision 3558-D01-2015.¹⁵

19. At paragraph 615 of Decision 2012-237, the Commission indicated that a company may choose to undertake a capital investment prior to applying for capital tracker treatment in a subsequent annual capital tracker filing. The Commission further clarified at paragraph 48 of Decision 2013-435:

48. It was acknowledged by the Commission that superior incentives for capital trackers would result if the companies were required to spend money on capital expenditures prior to receiving approval for capital tracker recovery of the expenditures. However, given the lack of experience with the capital tracker mechanism, for the first generation PBR plans, it was determined that the companies will be permitted to apply for capital trackers on a forecast basis. The approved forecast cost of a capital tracker project will be included in rates on an interim basis and will be subject to a true-up to prudently incurred actual expenditures, after the project is completed. The true-up process will test the prudence of the actual capital expenditures and imprudent expenditures will be subject to disallowance. As a result, the capital tracker mechanism retains some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred. The true-up mechanism with a

¹² Decision 2013-435, paragraphs 149-150.

¹³ Decision 3434-D01-2015: Distribution Performance-Based Regulation, Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015.

¹⁴ Decision 2013-435, paragraphs 1091-1092.

¹⁵ Decision 3558-D01-2015: Distribution Performance-Based Regulation, Commission-initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications, Proceeding 3558, Application 1611054-1, April 8, 2015.

prudence review also mitigates somewhat the incentive for companies to overstate the initial capital tracker forecasts. Nonetheless, the companies remained free to incur expenditures prior to applying for capital tracker approval. [footnotes removed]

20. With respect to Criterion 2, in Decision 2013-435, the Commission clarified that, in addition to asset replacement projects and projects required by an external party, in principle, a growth-related project will satisfy the requirements of Criterion 2. This is so where it can be demonstrated that the sum of the incremental revenues allocated to the project on some reasonable basis, the revenue provided under the I-X mechanism and any customer contributions to the project, are insufficient to offset the revenue requirement associated with the project in a PBR year.¹⁶ In certain circumstances, Criterion 2 may also permit consideration of certain projects for capital tracker treatment that do not fall into any of the growth-related, asset replacement or external party-related categories.

21. Under Criterion 3, the Commission determined that applying a materiality threshold to that portion of the revenue requirement for a project that is not funded under the I-X mechanism is warranted. The Commission established a two-tier materiality threshold. The first tier of the materiality threshold, a “four basis point threshold,” is to be applied at a project level (grouped in the manner approved by the Commission). The second tier of the materiality threshold, a “40 basis point threshold,” is to be applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.

22. Additionally, the Commission recognized the significance of the grouping of projects proposed for capital tracker treatment when it stated in paragraph 601 of Decision 2012-237:

601. ... The Commission also considers that it would not be suitable to group together several dissimilar projects into a single large project to give the appearance of materiality. However, a number of smaller related items required as part of a larger project might qualify for capital tracker treatment.

23. In Decision 2013-435, the Commission further elaborated that grouping of projects will require close scrutiny, since it will have a direct effect on the results of the accounting test and the project assessment under Criterion 1, as well as the assessment of materiality under Criterion 3. The Commission determined that the reasonableness of the grouping of capital projects is best assessed on a case-by-case basis for each company. The Commission indicated that it will require each company to provide sufficient justification for its proposed grouping of projects for capital tracker treatment.¹⁷

24. Finally, in Section 4.4 of Decision 2013-435, the Commission set out the K factor calculation methodology. Under the approved methodology, the K factor calculations sum the incremental revenue requirement amounts (i.e., additional to the amounts provided under the I-X mechanism) for each project or program approved for capital tracker treatment, as determined using the project net cost approach.

25. As set out in Decision 2012-237, the company will only be permitted to collect the forecast amounts for the capital tracker on an interim basis, and a true-up to the actual amount of

¹⁶ Decision 2013-435, paragraph 309.

¹⁷ Decision 2013-435, paragraphs 403 and 406.

the capital tracker will occur after the capital expenditures have been made. The Commission outlined the capital tracker true-up process as follows:

975. ... the March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.¹⁸

26. On true-up, a K factor adjustment will be made based on the actual dollars spent on the projects or programs approved for capital tracker treatment, with the difference between the approved forecast K factor amount and actual K factor amount refunded to, or collected from, customers.

2.2 ATCO Electric's prior capital tracker-related proceedings

27. Because the 2013 capital tracker proceeding leading to Decision 2013-435 had not yet been completed at the time the Commission established 2013 interim PBR rates in Decision 2013-072,¹⁹ the Commission approved, on an interim basis, a 2013 capital tracker placeholder (K factor) for ATCO Electric, equal to 60 per cent of the applied-for K factor amount. Accordingly, ATCO Electric was directed to include in its 2013 PBR rates a K factor placeholder of \$12.15 million on an interim basis.²⁰

28. Similar interim K factor placeholders were approved by the Commission for each of 2014, 2015 and 2016. In Decision 2013-461,²¹ the Commission approved on an interim basis a K factor placeholder in the amount of \$25.852 million to be included in ATCO Electric's 2014 PBR rates.²² In Decision 2014-354,²³ the Commission approved on an interim basis a 2015 K factor placeholder in the amount of \$51.347 million equal to 90 per cent of the proposed 2015 K factor.²⁴ In Decision 20822-D01-2015,²⁵ the Commission directed ATCO Electric to include a K factor placeholder for 2016 in its 2016 PBR rates equal to 90 per cent of the proposed 2016 K factor.²⁶

29. In Decision 2013-435, dealing with the 2013 capital trackers, the Commission did not approve any of ATCO Electric's projects for capital tracker treatment because the Commission

¹⁸ Decision 2012-237, paragraph 975.

¹⁹ Decision 2013-072: 2012 Performance-Based Regulation Compliance Filings, AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., ATCO Electric Distribution & Transmission Inc. and FortisAlberta Inc., Proceeding 2130, Application 1608826-1, March 4, 2013.

²⁰ Decision 2013-072, Table 1, paragraph 41.

²¹ Decision 2013-461: ATCO Electric Ltd., 2014 Annual PBR Rate Adjustment Filing, Proceeding 2824, Application 1609913-1, December 20, 2013.

²² Decision 2013-461, paragraph 111.

²³ Decision 2014-354: ATCO Electric Ltd., 2015 Annual PBR Rate Adjustment Filing, Proceeding 3404, Application 1610835-1, December 17, 2014.

²⁴ Decision 2014-354, paragraph 81.

²⁵ Decision 20822-D01-2015: ATCO Electric Ltd., 2016 Annual Performance-based Regulation Rate Adjustment Filing, Proceeding 20822, December 17, 2015.

²⁶ Decision 20822-D01-2015, paragraph 83.

did not accept the K factor calculation methodology used by ATCO Electric at that time.²⁷ Accordingly, the Commission directed ATCO Electric to retain its current 60 per cent K factor placeholder in its rates. Later, in Decision 2014-295,²⁸ the Commission approved an increase in the placeholder amount to 90 per cent of the revenue associated with the 2013 and 2014 applied-for capital trackers. The Commission approved offsetting the collection of this 90 per cent K factor placeholder against the placeholder amounts owing to ratepayers as a result of Decision 2014-169.²⁹

30. In Decision 3218-D01-2015, the Commission dealt with ATCO Electric's 2013 K factor true-up and 2014-2015 K factor forecast applications. In accordance with the Commission's determinations in that decision, ATCO Electric filed a compliance filing to address the identified issues and Commission directions. The resulting 2013 K factor true-up amount and 2014-2015 K factor forecast amounts were approved in the compliance filing Decision 20369-D01-2015 (Errata).³⁰ As set out in that decision, the Commission approved a 2013 actual K factor of \$13.3 million and the associated 2013 K factor true-up refund amount of \$9.804 million. The Commission also approved the 2014 and 2015 forecast K factors of \$35.7 million and \$48.3 million, respectively, on an interim basis pending future true-up proceedings.³¹

3 Commission process for reviewing 2014 capital tracker true-up and 2016-2017 capital tracker forecast

31. The Commission's process for reviewing ATCO Electric's 2014 true-up and 2016-2017 forecast capital tracker application will largely follow the same steps set out in Section 3 of Decision 3218-D01-2015.

32. Consistent with the determinations at paragraph 975 of Decision 2012-237 referenced in Section 2, the Commission considers that for the purposes of the true-up of the 2014 capital tracker projects or programs for which the Commission confirmed the need as part of its project assessment in Decision 3218-D01-2015, if there is no evidence on the record of this proceeding demonstrating that a project or program was not required in 2014, then there is no need to again demonstrate that a project or program was needed in order to provide utility service at adequate levels in 2014. However, the second part of the project assessment under Criterion 1 is still required so that the Commission can be satisfied that the scope, level and timing of each project or program was prudent, and the actual costs of the project or program were prudently incurred.

33. The Commission also considers that for the purposes of the true-up of the 2014 capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in Decision 3218-D01-2015, there is also no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless

²⁷ Decision 2013-435, paragraphs 825-827.

²⁸ Decision 2014-295: ATCO Electric Ltd., 2014 Interim Rates, Proceeding 3239, Application 1610590-1, October 24, 2014.

²⁹ Decision 2014-169: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009 (2010 Evergreen Application), Proceeding 240, Application 1605338-1, June 13, 2014 and Decision 2014-295, paragraphs 28-32.

³⁰ Decision 20369-D01-2015 (Errata): ATCO Electric Ltd., 2013-2015 Capital Trackers Compliance Filing, Proceeding 20369, August 31, 2015.

³¹ Decision 20369-D01-2015 (Errata), paragraphs 73-74.

the driver for the project or program has changed. However, the Commission will still undertake an assessment of the 2014 capital tracker projects and programs with respect to Criterion 3.

34. With respect to forecast capital projects or programs for 2016 and 2017 for which the company is seeking capital tracker treatment, the Commission will generally undertake assessments with respect to all three criteria for capital tracker treatment. However, in those instances where a project or program is part of an ongoing, multi-year program, or if a project or program is of an annual, recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. However, the second part of the project assessment component of Criterion 1 must still be demonstrated so that the Commission can be satisfied that the scope, level, timing and costs of each project or program are reasonable, on a forecast basis.

35. With respect to capital tracker projects and programs that have not been previously considered by the Commission and are requested on a forecast basis for 2016 or 2017, ATCO Electric calculated the K factor revenue requirement calculations for these projects and programs by incorporating the 2013 to 2014 actual and 2015 forecast capital additions for these projects or programs. In the absence of any evidence that the prior capital additions for the project were not reasonable, given the incentives under the I-X mechanism, the Commission will accept these prior year capital additions for purposes of calculating the second component of the accounting test. In making this determination, the Commission recognizes that the company was motivated to minimize costs with respect to capital projects funded pursuant to the revenues received under the I-X mechanism and that the company provided variance explanations in the business case for the actual expenditures over the most recent five-year period. These pre-capital tracker additions to rate base, however, will be included in the prudence review at the time of rebasing for purposes of establishing the going-in rates for the next generation PBR plan or in a general tariff application (GTA).

36. Similarly, for capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in prior capital tracker decisions, there is no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program has changed. However, the Commission will undertake assessments with respect to the materiality Criterion 3.

37. Section 4 of this decision provides an overview of the projects or programs for which ATCO Electric is seeking capital tracker treatment in 2014 on an actual basis and in 2016-2017 on a forecast basis. The evaluation of ATCO Electric's proposed capital project groupings is set out in Section 5. To evaluate ATCO Electric's proposed projects or programs pertaining to Criterion 1, common assumptions in ATCO Electric's capital expenditure forecasts, affiliate transactions, controls and accountability, and individual assessments of how each of ATCO Electric's projects or programs proposed for capital tracker treatment satisfy the project assessment requirements of Criterion 1 is set out in Section 6; and in Section 7, the Commission assesses ATCO Electric's accounting test model. The assessment under Criterion 2 is undertaken in Section 8, and the assessment under Criterion 3 is set out in Section 9. Section 10 deals with other matters raised in the proceeding. Section 11 addresses the K factor calculation methodology and the K factor true-up for 2014, as well as K factor forecasts for 2016 and 2017.

Finally, ATCO Electric's compliance with previous Commission directions is discussed in Section 12.

4 Summary of projects included in the 2014 capital tracker true-up and the 2016-2017 capital tracker forecast application

38. ATCO Electric's application was filed as Exhibit 20555-X0007. The schedules setting out ATCO Electric's capital tracker model for the years 2014 (on an actual basis), 2016 and 2017 (on a forecast basis) were filed as Exhibit 20555-0006, on June 19, 2015. These schedules were revised on August 10, 2015, in response to various information requests and filed as Exhibit 20555-X0022. The update affected most of the proposed capital tracker projects or programs.

39. As part of the 2014 capital tracker true-up, ATCO Electric applied for the true-up of 11 projects or programs approved by the Commission for capital tracker treatment on a forecast basis in Decision 3218-D01-2015, with subsequent updates in the compliance filing Decision 20369-D01-2015 (Errata).

40. As discussed earlier in Section 2.1, in Decision 2012-237³² and in Decision 2013-435,³³ the Commission indicated that a company may choose to undertake a capital investment prior to applying for capital tracker treatment. In other words, capital tracker treatment may be granted on the basis of actual capital expenditures, without prior approval of capital forecasts for a project. In Decision 3218-D01-2015, the Commission denied capital tracker treatment of the capital costs of the training facility component of the Nisku Pole and Training Facility Development project, because ATCO Electric did not satisfy the Commission in that proceeding that the entire scope, level, timing and costs of the project satisfied the project assessment requirements of Criterion 1.³⁴ In the compliance filing to Decision 3218-D01-2015, ATCO Electric removed all costs for 2012, 2013 and 2014 associated with the Nisku Pole and Training Facility Development project from the Building, Structures & Leasehold Improvements program, because it submitted that there was no definitive basis to split out only the training facility component.³⁵ ATCO Electric completed the 2014 scheduled work for this project and has applied to have the project reconsidered for 2014 capital tracker treatment on an actual cost basis, as further discussed in Section 6.2.3.3.

41. The projects and programs included in the 2014 capital tracker true-up and the resulting variance from the approved forecast resulting in a K factor true-up for 2014 are set out in the table below.

³² Decision 2012-237, paragraphs 614-615.

³³ Decision 2013-435, paragraph 48.

³⁴ Decision 3218-D01-2015, paragraph 187.

³⁵ Exhibit 20369-X0007, PDF page 7.

Table 1. Applied-for 2014 K factor true-up adjustments

Capital tracker program or project	2014 actual ³⁶	2014 forecast ³⁷	Variance
	(\$ million)		
Distribution to Transmission Contributions	0.7	0.8	(0.1)
Buildings, Structures & Leasehold Improvements	8.1	9.4	(1.3)
Information Technology Related	4.6	4.9	(0.3)
Tools and Instruments	1.7	2.1	(0.4)
Transportation Equipment	1.1	3.4	(2.3)
Third-Party Driven Relocations	0.9	1.4	(0.5)
New Extensions	2.9	6.3	(3.4)
Overhead Line Rebuilds, Replacements and Life Extension	2.8	2.7	0.1
Wood Pole Replacements and Life Extension	2.5	3.0	(0.5)
Reliability	0.4	0.9	(0.5)
Wildfire Risk Reduction	0.6	0.9	(0.3)
Total	26.3	36.0 [Note 1]	(9.5)

Note 1: Total does not match summation of each individual project or program due to rounding.

42. As part of the 2016-2017 capital tracker forecast, ATCO Electric applied for capital tracker treatment for 14 capital projects or programs in either or both of the years 2016 and 2017. Of these, 11 projects or programs were previously approved for capital tracker treatment in Decision 3218-D01-2015.³⁸ The remaining three projects or programs have not been previously approved for capital tracker treatment.

43. Table 2 below summarizes ATCO Electric's applied-for 2016 and 2017 capital trackers, the portion of the K factor adjustments related to each capital tracker project or program, and the total applied-for K factor adjustment for each of 2016 and 2017.

³⁶ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a), Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules), Schedule 1-1.

³⁷ Decision 20369-D01-2015 (Errata), Table 1.

³⁸ Decision 3218-D01-2015, ATCO Electric Ltd., 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast, Proceedings 3218, Applications 1610569-1, March 15, 2015.

Table 2. Applied-for 2016 and 2017 forecast capital tracker projects

Proposed capital tracker project or program	2016 forecast ³⁹	2017 forecast ⁴⁰
	(\$ million)	
Distribution to Transmission Contributions	3.0	4.9
Buildings, Structures & Leasehold Improvements	10.6	12.0
Information Technology Related	4.4	4.5
Tools and Instruments	1.7	1.7
Transportation Equipment	2.6	3.5
Third-Party Driven Relocations	2.0	2.3
New Extensions	10.6	14.0
Overhead Line Rebuilds, Replacements and Life Extension	3.4	4.0
Wood Pole Replacements and Life Extension	5.7	7.4
Reliability	1.0	1.1
Wildfire Risk Reduction	2.7	3.8
New capital tracker programs		
Distribution Automation	0.5	0.9
Transmission Driven	0.0	0.7
Underground Rebuilds, Replacements and Life Extension	0.0	0.5
Total	48.2	61.1 [Note 1]

Note 1: Total does not match summation of each individual project or program due to rounding.

5 Grouping of projects for capital tracker purposes

44. In Decision 2013-435, the Commission determined that the accounting test (Criterion 1) and the first tier of the materiality test (Criterion 3) will be applied to the approved groupings (i.e., either at a project or at a program level). The Commission also indicated that while the project assessment will generally be applied at the level of the approved project, the Commission will, where necessary, consider the individual component projects comprising the approved grouping in order to assess the need for the capital expenditures and the reasonableness of the forecast costs. The second tier of the materiality test will be applied at the level of all capital tracker projects, in the aggregate.⁴¹ The Commission also determined that the reasonableness of the grouping of capital projects is best assessed on a case-by-case basis for each individual company.⁴²

45. ATCO Electric submitted that for all previously approved capital tracker programs, ATCO Electric has maintained the same groupings in this application as those approved by the Commission in Decision 3218-D01-2015. ATCO Electric's proposed grouping of capital tracker

³⁹ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a), Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules), Schedule 1-1.

⁴⁰ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a), Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules), Schedule 1-1.

⁴¹ Decision 2013-435, paragraph 407.

⁴² Decision 2013-435, paragraph 406.

projects was found to be reasonable and was accepted by the Commission in Decision 3218-D01-2015.⁴³

46. ATCO Electric proposed three new capital tracker programs in this application, the Distribution Automation program, the Transmission Driven program and the Underground Rebuilds, Replacements and Life Extension program. For each of these new capital tracker programs, ATCO Electric submitted that it has maintained the same grouping as in Proceeding 3218.

47. ATCO Electric submitted that the Distribution Automation program is required to maintain the service reliability, quality and safe operation of its distribution system. ATCO Electric explained that projects in the Distribution Automation program target areas throughout its service territory where the distribution system can be improved by the use of distribution automation through two interdependent components: first, the installation of field supervisory control and data acquisition (SCADA) infrastructure; and second, the development and integration of control room technology and enterprise systems.⁴⁴ ATCO Electric submitted that the Distribution Automation program is also consistent with FortisAlberta's Distribution Control Centre/SCADA grouping, which the Commission approved in Decision 2013-435.⁴⁵

48. In response to an IR,⁴⁶ ATCO Electric explained that the Distribution Automation program was not a part of the IT Related program because the programs have different drivers and the nature of the projects in each program differ. Regarding the driver for each program, ATCO Electric noted that both the SCADA field devices and control room devices are interdependent and cannot operate without the other. Furthermore, the development and integration of control room technology in the Distribution Automation program is required to improve the reliability and safety of the system through the use of automated control of physical SCADA-enabled assets in the field. In contrast, ATCO Electric submitted that the capital projects within the IT Related program are required to achieve third-party driven regulatory and operational compliance and support company growth. Therefore, in ATCO Electric's view, the two programs did not share a common driver for capital investment.

49. ATCO Electric identified differences in the nature of the projects in the Distribution Automation program as compared to those in the IT Related program as follows:

The capital projects within the Distribution Automation Program consist of projects similar in nature. The capital projects associated with the development and integration of control room technologies are required to safely and effectively operate the electrical distribution system through SCADA. These technologies enable ATCO Electric Distribution to monitor status and automate control of physical assets, conduct real time or predictive load flow simulations, and enable future applications such as Volt-Var control of the electrical system.

The IT Related Program consists of projects related to the infrastructure and business applications for Information Technologies (IT) necessary for information processing and utilization by the entire organization on the Enterprise. Several examples would be those

⁴³ Decision 3218-D01-2015, paragraphs 87-88.

⁴⁴ Exhibit 20555-X0007, PDF page 25.

⁴⁵ Decision 2013-435, paragraphs 1003-1004.

⁴⁶ Exhibit 20555-X0023, AE-AUC-2015JUL20-004.

required for Asset Management, Geo-spatial Information Systems (GIS), Outage Management, and Meter Data Management. The data within these technologies contains information such as asset types, locations, or even work dispatch or outage tracking, but none are used to operate the physical assets used by ATCO Electric to provide distribution services.⁴⁷

50. ATCO Electric also explained in an IR response that the Distribution Automation program was not a part of the Communication Structures and Equipment program (a non-capital tracker program) because they do not share a common driver for capital investment. For example, under the Distribution Automation program, capital projects are required to enable local communication networks to communicate between the SCADA-enabled devices in the field and the main telecommunication network. In contrast, the capital projects within the Communication Structures and Equipment program consist of capital additions related to the installation and maintenance of the back-bone telecommunication towers and equipment and mobile radio equipment, which are used by the entire organization.⁴⁸

51. ATCO Electric submitted that the Transmission Driven program consists of capital additions, net of contributions, driven by transmission projects. Projects may consist of relocating lines, extending or reconfiguring lines to reach relocated substation locations, purchase of transmission line assets where distribution circuits are under strung on transmission lines that are to be decommissioned, and similar projects. ATCO Electric clarified that this program does not include projects that are associated with transmission projects that are required to address a capacity, reliability or other distribution deficiency as defined in a Distribution Deficiency Report to the AESO. ATCO Electric submitted that the Transmission Driven program is similar to FortisAlberta's Substation Associated Upgrades program⁴⁹ and ATCO Gas' Transmission Driven program,⁵⁰ both of which the Commission found to meet the project assessment requirement of Criterion 1.⁵¹

52. In ATCO Electric's view, the Underground Rebuilds, Replacements, and Life Extension program is required to maximize the life of underground line components and to replace deteriorated, damaged and defective equipment as failures and test results indicate the need. Underground lines and components are of a similar nature or function and the need to maximize the life of these assets and to ultimately replace them has a common requirement for capital investment. ATCO Electric submitted that this program is consistent with ATCO Electric's Overhead Line Rebuilds, Replacement and Life Extension program,⁵² which was approved by the Commission in Decision 3218-D01-2015.⁵³

53. The CCA noted that prior to PBR, ATCO Electric had two programs, a Capital Maintenance program and a Large System Improvements program, in contrast to the 11 projects

⁴⁷ Exhibit 20555-X0023, AE-AUC-2015JUL20-004(a).

⁴⁸ Exhibit 20555-X0023, AE-AUC-2015JUL20-004(b).

⁴⁹ Decision 3220-D01-2015: FortisAlberta Inc., 2013-2015 PBR Capital Tracker Application, Proceeding 3220, Application 1610570-1, March 5, 2015, paragraph 220.

⁵⁰ Decision 3267-D01-2015: ATCO Gas and Pipelines Ltd. 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast, Proceeding 3267, Application 1610634-1, March 19, 2015, paragraph 350.

⁵¹ Exhibit 20555-X0007, PDF page 25.

⁵² Exhibit 20555-X0007, PDF page 26.

⁵³ Decision 3218-D01-2015, paragraphs 368 and 375.

or programs which ATCO Electric identified in an IR response in the application, which is replicated below.⁵⁴

Table 3. Comparison of capital categories from previous GTA/Rule 005⁵⁵ filings with 2013-2015 program groupings⁵⁶

Line	Schedule 20-4 Categories (from 2011/2012 GTA application)	Schedule 4.2 - D Categories (from 2013 Rule 005 filing)	Schedule 1-1 Capital program groupings
1	Small New Extensions	Small New Extensions	New Extensions, Historical REAs
2	Large New Extensions	Large New Extensions	
3	Capital Maintenance	Capital Maintenance	Capacity Additions Clearance & Safety Distribution Automation Third-Party Driven Relocations Revenue Meter Replacements Overhead Line Rebuilds, Replacements and Life Extensions Wood Pole Replacement and Life Extensions Reliability Transmission Driven Underground Rebuilds & Replacements Wild Fires Mitigation
4	Large System Improvements	Large System Improvements	
5	Distribution Contributions to Transmission	Distribution Contributions to Transmission	Distribution to Transmission Contribution
6	Telecommunication	Telecommunication	Communications Structures & Equipment
7	Communication Equipment	Communication Equipment	
8	Isolated Generation	Isolated Generation	Isolated Generation
9	Tools, Instruments and Equipment	Tools, Instruments and Equipment	Tools & Instruments
10	Office Furniture and Equipment	Office Furniture and Equipment	Office Furniture Replacements
11	Software Development Projects	Software Development Projects	Information Technology Related
12	Transportation Equipment	Transportation Equipment	Transportation Equipment
13	Land, Buildings and Structures	Land, Buildings and Structures	Buildings, Structures & Leasehold Improvements
14	General Property and Equipment (GP&E) costs	See Note 1	

Note 1: In the 2013 Rule 005 filing (Schedule 4.2D), ATCO Electric included allocated GP&E costs related to Land, Buildings and Structures, Office Furniture and Equipment, and Software Development Projects within those respective categories.

54. Specifically, the CCA raised concerns regarding the following non-capital tracker programs: the Capacity Additions program, Clearance and Safety program, Rural Electrification Association distribution system program (REAs) and Revenue Meter Replacements program. ATCO Electric pointed out that the Capacity Additions program and the Clearance and Safety program used to be a part of the Capital Maintenance program and the Large System Improvements program. Additionally, the CCA noted that the REAs program was formerly a part of the New Extensions capital program, and the Revenue Meter Replacements program used to be a part of the Large System Improvements capital program. The CCA recommended that the

⁵⁴ Exhibit 20555-X0076, CCA argument, paragraph 8.

⁵⁵ Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

⁵⁶ Exhibit 20555-X0023, AE-AUC-2015JUL20-001.

Capacity Additions program, Clearance and Safety program, REAs program and Revenue Meter Replacement program be grouped under the Capital Maintenance program and the Large System Improvement program, as was done in the past, and that ATCO Electric should be directed to file the revised groupings in its compliance filing.⁵⁷

55. The CCA also submitted that ATCO Electric provided no details on the capital expenditures from 2013 to 2016 for the Transmission Driven and Underground Rebuilds, Replacements and Life Extension programs, which only surpassed the materiality threshold in 2017.⁵⁸ The CCA submitted that it is unfair to the extent that savings in 2013-2016 are retained by ATCO Electric under I-X, but customers are expected to incur costs through rates flowing from a capital tracker with no claim on those savings from prior years.⁵⁹

56. ATCO Electric provided a description of all non-capital tracker projects and programs with actual or forecast capital additions in the year for 2014 or 2016 and 2017 respectively in appendix G⁶⁰ of its application, which also included descriptions of the non-capital tracker programs that the CCA raised concerns about, namely, the Capacity Additions program, Clearance and Safety program, REAs program and Revenue Meter Replacements program.

57. ATCO Electric explained that its Capacity Additions program is required for upstream system capacity improvements driven by infill projects and new area development in order to maintain system voltages and currents at acceptable levels. These projects are system upgrades which require capital expenditures that cannot be attributed to a single customer or identifiable group of customers, and include increasing system capacity, developing new main feeders, increasing conductor size, adding equipment, and any other system upgrades required to expand system capacity.⁶¹

58. As a rationale for its Clearance and Safety program, ATCO Electric provided the following explanation:

The Clearance and Safety Program is to mitigate public and worker safety risks associated with inadequate clearance under power lines, including projects to mitigate clearance violations between overhead distribution conductors and ground or navigable water. This project also includes capital vegetation management programs adjacent to the Distribution rights-of-way, where they occur outside of the forest protection areas.⁶²

59. ATCO Electric noted that the REAs program is for projects associated with the purchase of REAs and that it separately groups REA purchase costs pursuant to Commission directions in Decisions 2013-296⁶³ and 2013-461.⁶⁴

60. ATCO Electric submitted that the Revenue Meter Replacements program is for projects to upgrade or replace revenue meters. Examples include ATCO Electric's Automated Meter

⁵⁷ Exhibit 20555-X0076, CCA argument, paragraphs 13-14.

⁵⁸ Exhibit 20555-X0007, application, Table 3.8-2, pages 58-59; paragraph 184 and Table 3.8-8.

⁵⁹ Exhibit 20555-X0076, CCA argument, paragraph 12.

⁶⁰ Exhibit 20555-X0007.

⁶¹ Exhibit 20555-X0007, Appendix G, PDF page 135.

⁶² Exhibit 20555-X0007, PDF page 135.

⁶³ Decision 2013-296: ATCO Electric Ltd., Rate Regulation Initiative, Performance-Based Regulation, Z Factor Adjustment Application, Proceeding 2301, Application 1609120-1, August 9, 2013.

⁶⁴ Exhibit 20555-X0007, PDF page 135.

Reading (AMR) implementation, Interval Metering Enhancements, and Advanced Meter Infrastructure Planning.⁶⁵

61. In its reply argument, ATCO Electric submitted that the CCA did not file evidence, IRs or discuss merging non-tracker projects with capital tracker projects during its cross-examination of the ATCO Electric panel, even though the CCA recommended consolidation of ATCO Electric's groupings in argument. ATCO Electric argued that it therefore, "... has been denied the opportunity to know the case it has to meet and to respond accordingly."⁶⁶

62. ATCO Electric noted that the table presented in AE-AUC-2015JUL20-001 was originally filed as an undertaking⁶⁷ to Mr. Wachowich in Proceeding 3218 and that the grouping in this application is consistent with the grouping in Proceeding 3218, which was approved by the Commission in Decision 3218-D01-2015.⁶⁸ ATCO Electric further argued:

In this Proceeding, the CCA appears to be repackaging substantially the same arguments for merging non-trackers with capital trackers, which were previously rejected in Decision 3218-D01-2015 and Decision 2013-435 only this time without notice to the utility. For example, Meters were specifically discussed in Proceeding 3218 and the Commission accepted the Tracker groupings in that Proceeding as applied for. Paragraph 711 of 2013-435 also directed smaller (subprogram level) groupings to be used, as opposed to larger ones, and was the subject of much discussion in Proceeding 3218.

The CCA's recommendation to merge four capital programs (i.e. Capacity Additions, Clearance and Safety, REA's, and Meters) "as they were in the past," is also contrary to capital tracker grouping rationale, as no common requirement for investment exists among these categories, nor between those and other capital program groupings shown in grouping Table 1.⁶⁹

63. Regarding the CCA's recommendation, ATCO Electric concluded, "...given that there was no direction in Decision 3218-D01-2015 to merge any of the non-tracker groups with the tracker groups, and given there was no discussion of this proposal in evidence or cross examination at the hearing; the CCA's recommendation must again be rejected."⁷⁰

Commission findings

64. The Commission has considered the CCA's proposal to merge certain programs into the Capital Maintenance and the Large System Improvements programs. The Commission finds that the CCA has not satisfactorily explained any commonality driving the requirement for investment amongst the Capacity Additions program, Clearance and Safety program, REAs program and Revenue Meter Replacements program. The Commission accepts ATCO Electric's explanation that the Capacity Additions program and the Clearance and Safety program each have their own unique driver requiring investment, and include projects that are of a sufficiently similar nature, to warrant grouping into a single program. In Decision 2013-296, the Commission set out certain conditions for the purchase of REAs under the PBR framework which, if the

⁶⁵ Exhibit 20555-X0007, Appendix G, PDF page 135.

⁶⁶ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 52.

⁶⁷ Proceeding 3218, Exhibit 0063.01-AE-3218.

⁶⁸ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 54.

⁶⁹ Exhibit 20555-X0080, ATCO Electric reply argument, paragraphs 54-55.

⁷⁰ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 56.

utility satisfies, may qualify it for a Commission directed Y factor adjustment. Accordingly, the Commission is of the view that it reasonable for REAs to have their own capital grouping.

65. Regarding the Revenue Meter Replacements program, the Commission notes that this program previously used to be a part of the New Extensions program, as shown in Table 3 above. In Proceeding 3218, ATCO Electric provided the following argument to justify a separate grouping for the Revenue Meter Replacements program:

Meters for New Extensions have a significantly different requirement for capital investment than replacement meters. New metering installations have and continue to be designed, estimated and added as part of the New Extension program. They are proportional to growth in Customer Additions and offset in many cases by Customer Contributions. Replacement meters and large metering renewal projects, on the other hand, are not proportional to growth and do not attract customer contributions. They are not programs of a similar nature therefore, nor do they have a common requirement for capital.⁷¹

66. The argument provided by ATCO Electric in Proceeding 3218 was accepted by the Commission when it approved ATCO Electric's overall grouping in Decision 3218-D01-2015.⁷² The Commission finds that the CCA did not provide sufficient evidence to demonstrate that a different approach to grouping for this program is required at this time and, accordingly, the Commission remains of the view that the grouping for this program is reasonable.

67. The Commission is further assured that ATCO Electric has not manipulated the groupings of its applied-for capital programs in light of the fact that these groupings are consistent with the groupings used in Proceeding 3218, as evident by the table presented in AE-AUC-2015JUL20-001, which was also filed as an undertaking⁷³ in Proceeding 3218.

68. The Commission has also reviewed ATCO Electric's description of the nature, scope and timing of its non-capital tracker projects in Appendix G of the application,⁷⁴ which ATCO Electric provided so that parties could gain a better understanding of the proposed groupings of the capital projects and programs for which ATCO Electric is seeking capital tracker treatment, and finds that ATCO Electric has complied with the direction at paragraph 50 of Decision 3558-D01-2015.

69. From its review of Appendix G, the Commission notes that the non-capital tracker Office Furniture program includes capital additions for the replacement or addition of office furniture and equipment, but does not include furniture provided as part of a new building project.

70. In Decision 20407-D01-2016,⁷⁵ the Commission made the following finding:

89. The Furniture Life Cycle replacement project consists of costs related to repairing and replacing furniture, and making ergonomic changes to work stations at EPCOR's [EPCOR Distribution & Transmission Inc.] service centres. EPCOR explained

⁷¹ Proceeding 3218, Exhibit 0083.01.AE-3218, ATCO Electric reply argument, paragraph 90.

⁷² Decision 3218-D01-2015, paragraph 87.

⁷³ Proceeding 3218, Exhibit 0063.01-AE-3218.

⁷⁴ Exhibit 20555-X0007.

⁷⁵ Decision 20407-D01-2016: EPCOR Distribution & Transmission Inc., 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20407, February 7, 2016.

that the Work Centre Redevelopment project also includes furniture expenditures related to the acquisition of the building at the NSC [North Service Centre] location and the redevelopment of the existing NSC and SSC [South Service Centre] locations. The Commission considers that both projects represent expenditures related to acquiring furniture and work stations for use at EPCOR's service centre locations. While the furniture expenditures related to the Work Centre Redevelopment project are being driven by the expansion and redevelopment of the work centres, the furniture related assets may eventually require replacement as part of the Furniture Life Cycle replacement project. Accordingly, the Commission finds that the Furniture Life Cycle replacement is sufficiently similar to components of the Work Centre Redevelopment project and have drivers that are sufficiently related to warrant being grouped together for capital tracker purposes.

90. Given the Commission's findings regarding the three non-capital tracker projects and the Work Centre Redevelopment project, the Commission directs EPCOR to include all four projects (Work Centre Redevelopment project, North and South Service Centre Building Life Cycle Replacements project, Service Centre Consolidation project and the Furniture Life Cycle replacement project) in a single group for the purposes of capital tracker analysis in its compliance filing to this decision, as provided by EPCOR in Table 3. Similar to the directions in Section 5.2.1 above, while grouping these projects into a single program, EPCOR should continue filing separate business cases for the purpose of project assessment and showing different line entries in the accounting test model for these projects, as shown in Table 3. This is similar to an approach that EPCOR currently uses for its Third-Party Driven Relocations program.⁷⁶

71. ATCO's Electric's Office Furniture program and EPCOR's Furniture Life Cycle Replacement Program appear similar enough to warrant an exploration of whether ATCO Electric's Office Furniture program can be grouped with the Buildings, Structures and Leasehold Improvements program. Therefore, for the true-up of its 2015 capital tracker application, ATCO Electric is directed to explain why the Office Furniture program should be a separate program and not a part of the Buildings, Structures and Leasehold Improvements program.

72. Consistent with the approach set out in previous capital tracker decisions, as described in in Decision 3558-D01-2015,⁷⁷ to the extent that the groupings in the present 2014 true-up and 2016-2017 forecast capital tracker application are the same as approved in Decision 3218-D01-2015, the Commission will not re-evaluate those groupings in this decision, except to the extent that those groupings were subject to Commission directions or other issues arising in this proceeding. However, any new groupings that are proposed in this proceeding will be assessed by the Commission in this decision.

73. The Commission has reviewed the rationale for the grouping of the Distribution Automation program, Transmission Driven program and the Underground Rebuilds, Replacements and Life Extension program. The Commission accepts the grouping of projects in the Distribution Automation program, Transmission Driven program and Underground Rebuilds, Replacements, and Life Extension program. Regarding the Distribution Automation program, the Commission finds it is reasonable to group both the SCADA field devices and control room devices projects as they are interdependent and are driven by a common requirement. Also, the Commission finds it is reasonable to group projects in the Transmission Driven program as they

⁷⁶ Decision 20407-D01-2016, paragraphs 89-90.

⁷⁷ Decision 3558-D01-2015, paragraph 51.

are driven by the common requirement of responding to changes in the transmission system. Similarly, the expenditures in the Underground Rebuilds, Replacements and Life Extension program are driven by replacements and life extension of all asset classes associated with underground lines, including poles and fixtures, underground cables, underground services, equipment, and transformers and, therefore, are of a sufficiently similar nature to warrant grouping into a single program. The Commission also notes that it has previously approved a grouping of ATCO Electric's capital program Overhead Line Rebuilds, Replacements and Life Extension program.⁷⁸

74. With regard to the CCA's submission on the unfairness of ATCO Electric being allowed to retain the possible savings on Transmission Driven and Underground Rebuilds, Replacements and Life Extension programs during the years that it had not reached the materiality threshold to qualify as a capital tracker, the Commission finds that its finding in Decision 3267-D01-2015 still applies:

With regard to the CCA's proposal that multiple years be grouped for the purpose of the accounting test or that a higher threshold be applied to capital trackers that were not included in the previous year's rates, the Commission considers that this proposal would constitute a major change to the approach to grouping approved in Decision 2013-435, and is, therefore, rejected.⁷⁹

75. For the purpose of this decision, the Commission accepts ATCO Electric's grouping of projects, as proposed in this application.

6 Project assessment under Criterion 1 – The project must be outside of the normal course of the company's ongoing operations

76. As discussed in Section 3 of this decision, consistent with paragraph 150 of Decision 2013-435, each of ATCO Electric's projects or programs proposed for capital tracker treatment will be evaluated against the project assessment requirements of Criterion 1. The purpose of the project assessment component of Criterion 1 is to demonstrate that a project proposed for capital tracker treatment is required in order to maintain utility service at adequate levels, as required by paragraph 594 of Decision 2012-237, and that the actual scope, level, and timing of the project are prudent and that costs of the project are reasonable for forecast projects and prudent for completed projects.

77. ATCO Electric's capital trackers applied for in this application can be broadly divided into two categories. The first category is composed of applied-for projects or programs previously approved for capital tracker treatment in Decision 3218-D01-2015. As set out in Section 4 of this decision, this category includes all of the projects or programs comprising the 2014 true-up and the majority of projects or programs forming part of the 2016 and 2017 forecasts. The second category is composed of the remaining projects or programs to be implemented in 2016 or 2017 that have not been previously approved for capital tracker treatment.

⁷⁸ Decision 3218-D01-2015, paragraphs 368 and 375.

⁷⁹ Decision 3267-D01-2015: ATCO Gas and Pipelines Ltd., 2013 PBR Capital Tracker Refiling and True-up and 2014-2015 PBR Capital Tracker Forecast, Proceeding 3267, Application 1610634-1, March 19, 2015, paragraph 117.

78. ATCO Electric provided a business case together with an engineering study (where ATCO Electric considered either document to be applicable) for each of its new projects or programs proposed for capital tracker treatment in 2016 and/or 2017. For projects or programs that were previously approved by the Commission, ATCO Electric provided project updates. In its business cases and project updates, as supplemented by other evidence filed in the proceeding, ATCO Electric has generally provided an assessment of its proposed capital tracker projects consistent with the minimum filing requirement guidelines set out in Decision 3558-D01-2015.

79. The Commission has evaluated ATCO Electric's business cases, engineering studies, cost related information, and related evidence and argument against each of the project assessment minimum filing requirements. However, for the purposes of this decision, the Commission has commented only on those aspects of the minimum filing requirements that the Commission considers are insufficiently addressed by ATCO Electric's evidence or were otherwise raised as an issue in the proceeding. In future capital tracker applications, ATCO Electric should continue to provide similar information with respect to each of the minimum filing requirements, including business cases, engineering studies and cost related information, including costs by cost category, unit costs and historical cost comparators, in sufficient detail to allow an evaluation of the reasonableness of its forecasts and the prudence of its incurred costs.

80. The balance of this section is organized as follows: Section 6.1 deals with common issues related to the project assessment of ATCO Electric's projects or programs, such as inflation assumptions, overhead allocations, affiliate transactions, and the company's internal cost controls and accountability mechanisms with respect to quality, safety and cost for capital projects approved for capital tracker treatment. The Commission's project assessment under Criterion 1 of ATCO Electric's projects or programs previously approved for capital tracker treatment in Decision 3218-D01-2015 is set out in Section 6.2. The project assessment of ATCO Electric's projects or programs that have not been previously approved for capital tracker treatment in Decision 3218-D01-2015 is set out in Section 6.3.

6.1 Common issues

6.1.1 Common assumptions in ATCO Electric's capital expenditure forecasts

6.1.1.1 Inflation rates

81. ATCO Electric used the following inflation factors for its 2016 and 2017 capital tracker forecasts:

- A 3.75 per cent labour inflation rate was applied for union and non-union staff for both years and reflects the overall expected average increase for employees.
- An inflation rate of two per cent in 2016 and four per cent in 2017 was applied for contractor costs.
- An "other" inflation rate of 2.10 per cent was applied in both 2016 and 2017.⁸⁰

82. ATCO Electric explained that for its union employees, who belong to the Canadian Energy Workers Association (CEWA), there is a collective bargaining agreement in place for 2016 that provides an increase of 3.75 per cent. The collective agreement expires on December 31, 2016. For the purposes of a 2017 forecast union inflation rate, ATCO Electric

⁸⁰ Exhibit 20555-X0007, application, paragraph 88.

used the 2016 value.⁸¹ The non-union labour inflation factors are the same as the union inflation rates in both 2016 and 2017, and “reflect ATCO Electric’s forecast of the increases required given the outlook for the labour market.”⁸²

83. The contractor inflation rate for 2016 of two per cent is reflective of ATCO Electric’s experience regarding 2015 contractor rates given “weakened economic conditions.”⁸³ The 2017 rate of four per cent was based on the expectation that economic conditions would improve by that time.⁸⁴

84. ATCO Electric explained that the “other” inflation rate is used to forecast various material costs,⁸⁵ and is based on an average of Alberta Consumer Price Index (CPI) forecasts for 2016 and 2017.⁸⁶ The following table summarizing the CPI forecasts was provided by ATCO Electric in support of its “other” inflation rate forecast:

Table 4. CPI projections used in ATCO Electric’s “other” inflation rate forecast⁸⁷

Source	Date of forecast	2016 forecast (%)	2017 forecast (%)
Alberta Treasury Branch (ATB)	January 2015	2.0	2.1
Bank of Montreal	February 2015	2.0	N/A
Royal Bank of Canada (RBC) financial group	February 2015	2.0	N/A
Toronto Dominion (TD) Bank	January 2015	2.4	N/A
Alberta Government Budget 2014	March 2014	2.0	2.0
Average⁸⁸		2.1	2.1

85. In its application, ATCO Electric noted that the applied-for inflation rates were based on the assumptions and information available at the time its forecasts were made, and that capital tracker projects are trued-up to actuals.⁸⁹

86. Regarding its labour inflation rates, ATCO Electric provided the following historical average increases in an IR response to the CCA:

⁸¹ Transcript, Volume 2, page 305, line 20 to page 306, line 3 (Mr. McNabb).

⁸² Exhibit 20555-X0007, application, paragraph 89.

⁸³ Exhibit 20555-X0007, application, paragraph 90.

⁸⁴ Exhibit 20555-X0007, application, paragraph 90.

⁸⁵ Exhibit 20555-X0023, AE-AUC-2015JUL20-006(b).

⁸⁶ Exhibit 20555-X0007, application, paragraph 90.

⁸⁷ Exhibit 20555-X0023, AE-AUC-2015JUL20-006(c).

⁸⁸ The averages presented in this table are from Exhibit 20555-X0023, AE-AUC-2015JUL20-006(c), and do not represent exact averages due to rounding.

⁸⁹ Exhibit 20555-X0007, application, paragraph 92.

Table 5. ATCO Electric actual labour inflation rates, by employee type, from 2013 to 2015⁹⁰

Employee type	2013 (%)	2014 (%)	2015 (%)
Union	3.5	3.5	3.5
Non-union	3.1	3.8	0.6

87. In an IR response to the Commission, ATCO Electric explained that it had forecast both its union and non-union inflation rates to be 3.75 per cent for each of 2016 and 2017 as this approach was consistent with its past forecast inflation method. ATCO Electric added that its non-union labour salary escalations would be “managed as appropriate given economic conditions.”⁹¹ ATCO Electric noted that the economic conditions in 2015 were reflected in the 2015 non-union inflation rate of 0.6 per cent, shown above.⁹² Regarding the differences between non-union and union labour inflation rates over time, ATCO Electric indicated:

... over time increasing non-CEWA compensation at the same rate as CEWA compensation is required to mitigate salary compression such as between CEWA members and their front-line supervisors.⁹³

88. During the hearing, Mr. McNabb, appearing for ATCO Electric, elaborated, stating that if union employees are given larger salary increases than their non-union supervisors, there could be a situation where the supervisor is paid less than the union employee reporting to them.⁹⁴

89. In support of the contractor inflation rate in 2016 and 2017, and its stated expectation that the economic outlook for Alberta would improve to a normalized state by 2017, ATCO Electric provided Gross Domestic Product (GDP) forecasts for Alberta for the years in question, as set out in the Table 6.

90. At the hearing, Mr. McNabb provided updated GDP forecasts by way of an undertaking response. The updated GDP forecasts are also set out in Table 6 below:

⁹⁰ Exhibit 20555-X0023, AE-CCA-2015JUL20-004(a).

⁹¹ Exhibit 20555-X0023, AE-AUC-2015JUL20-007(a).

⁹² Exhibit 20555-X0023, AE-AUC-2015JUL20-007(a).

⁹³ Exhibit 20555-X0023, AE-AUC-2015JUL20-007(a).

⁹⁴ Transcript, Volume 2, page 296, lines 1-11 (Mr. McNabb).

Table 6. GDP forecasts provided by ATCO Electric for Alberta in 2016 and 2017⁹⁵

Source	Date of forecast	2016 forecast (%)	2017 forecast (%)
ATB Financial economic outlook Q2 2015	March 31, 2015	1.7	3.1
RBC Economics provincial outlook	June 2015	1.7	N/A
Alberta Government economic outlook	March 26, 2015	1.7	3.0
Updated GDP forecasts			
ATB Financial economic outlook Q 2015 ⁹⁶	October 1, 2015	1.4	1.8
RBC Economics provincial outlook ⁹⁷	September 2015	0.6	N/A
Alberta Government economic outlook ⁹⁸	July 2015	1.3	N/A

91. In response to a question from Commission counsel, Mr. McNabb further explained the link between its labour inflation rates and the GDP forecasts:

I think this all ties into various parts of our out-of-scope increases. And, I think, as we mention in this IR, we do determine the increases based on the market conditions and the labour market in that year, and we will govern those increases accordingly.

So for '15, given the downturn in the economy, you certainly saw that the labour increases for out of scope are very minimal, only at .6 percent.

So you are seeing the reality of the downturn in the economy impact our out-of-scope increases. It's just for our forecast we thought it was a reasonable method to base the forecast consistent with CEWA [Canadian Energy Workers' Association], which is what we've traditionally done.⁹⁹

92. ATCO Electric submitted that having its non-union labour rates equal to its union labour rates for 2016 and 2017 was reasonable on a forecast basis. ATCO Electric also explained that the impact of a one per cent change in its forecast labour inflation rate would have an impact on the total K factor calculation of some \$200,000 and therefore did not have a material impact on its K factor, which is ultimately trued up to actuals.¹⁰⁰

93. In its argument, in consideration of the declining GDP forecast, the CCA initially recommended that the Commission approve a non-union labour inflation factor of 2.71 per cent for 2016. The CCA's recommended labour rate for 2016 was a weighted average of the 2016 3.75 per cent negotiated rate for union employees, which makes up approximately two-thirds of ATCO Electric's staff, and the 2015 actual non-union labour rate of 0.6 per cent. For the 2017 forecast, the CCA initially recommended a labour inflation factor of one per cent, calculated as the weighted average of a zero per cent increase for CEWA employees and a reasonable increase

⁹⁵ Exhibit 20555-X0023, AE-AUC-2015JUL20-007(b).

⁹⁶ Exhibit 20555-X0052, undertaking response by Mr. McNabb to Mr. Wachowich at Transcript, Volume 1, page 63.

⁹⁷ Exhibit 20555-X0052, CCA aid to examination, RBC provincial outlook.

⁹⁸ Exhibit 20555-X0052, undertaking response by Mr. McNabb to Mr. Wachowich at Transcript, Volume 1, page 63.

⁹⁹ Transcript, Volume 2, page 298, lines 1-20 (Mr. McNabb).

¹⁰⁰ Transcript, Volume 2, page 301, lines 5-13 (Mr. McNabb).

of three per cent for non-union employees to account for ATCO Electric's concern with salary compression.¹⁰¹

94. ATCO Electric stated in argument that, on a forecast basis, its inflation rates are reasonable for 2016 and 2017 given that the costs will be trued up to actuals and given the potential for salary compression between union and non-union labour rates.¹⁰²

95. In its reply argument, the CCA altered its recommendation for forecast labour increases in 2016 and 2017. The CCA referred to correspondence submitted by the UCA on November 30, 2015,¹⁰³ that discussed employee layoffs within the ATCO Group, which includes ATCO Electric. The CCA acknowledged that "it is not known how many of these layoffs will be ATCO Electric Distribution employees" but argued that there are no grounds for inflationary increases for staff, and recommended that the labour inflation rates for 2016 and 2017 be zero per cent and one per cent, respectively.¹⁰⁴

Commission findings

96. The evidence on the record of this proceeding suggests that economic growth forecasts for Alberta have trended downwards since ATCO Electric filed its application. However, positive economic growth is still expected, as shown in Table 6. The Commission considers that there is insufficient evidence with respect to employee layoffs specific to ATCO Electric to justify that the labour inflation rates for 2016 and 2017 be zero per cent and one per cent, respectively, as recommended by the CCA. Additionally, as discussed in the Commission's ruling dated December 3, 2015,¹⁰⁵ which dealt with the UCA's November 30, 2015 letter on the subject of the ATCO Group layoffs, the forecasts approved in this decision provide interim funding and the actual costs will be addressed in the capital tracker true-up proceedings.

97. Nonetheless, the evidence in this proceeding suggests that the forecasts for economic growth in Alberta since ATCO Electric filed its application have trended downwards for 2016 and 2017. The effects of lower economic growth in Alberta are further illustrated in ATCO Electric's actual 2015 non-union labour inflation rate of 0.6 per cent. The Commission notes that when ATCO Electric filed its application, economic forecasts were predicting growth to recover in 2016 as compared to 2015. However, during the hearing, updated growth forecasts were provided which indicated that economic growth in 2016 would experience a more "gradual recovery" than originally anticipated.¹⁰⁶ In light of the updated economic growth forecasts and ATCO Electric's evidence that its labour inflation rates take into account the "outlook of the labour market,"¹⁰⁷ the Commission does not find ATCO Electric's non-union labour inflation rates for 2016 and 2017 of 3.75 per cent to be reasonable. The Commission finds that a more moderate non-union labour inflation rate for 2016 and 2017 of 3.00 per cent is reasonable for the purpose of the accounting test to be used in forecasting 2016 and 2017 capital tracker expenditures, given the lower economic growth forecasts for Alberta. ATCO Electric is directed

¹⁰¹ Exhibit 20555-X0076, CCA argument, paragraphs 53-54.

¹⁰² Exhibit 20555-X0075, ATCO Electric argument, paragraphs 234-235.

¹⁰³ Exhibit 20555-X0077, UCA letter, November 30, 2015.

¹⁰⁴ Exhibit 20555-X0082, CCA reply argument, paragraph 55.

¹⁰⁵ Exhibit 20555-X0079, AUC letter December 3, 2015.

¹⁰⁶ Exhibit 20555-X0052, undertaking response by Mr. McNabb to Mr. Wachowich at Transcript, Volume 1, page 63.

¹⁰⁷ Exhibit 20555-X0007, application, paragraph 89.

to reflect these non-union labour inflation rates in its compliance filing application to this decision.

98. Regarding ATCO Electric's union labour inflation rate for 2016 of 3.75 per cent, the Commission recognizes that this rate was negotiated in an agreement that was ratified on October 7, 2014. Accordingly, the Commission approves the 2016 union inflation rate as filed. For the 2017 union labour inflation rate, the Commission considers that a forecast that better reflects current economic expectations for 2017 is warranted. Accordingly, consistent with the non-union labour inflation rates for 2016 and 2017, the Commission finds that a union labour inflation rate of 3.00 per cent is reasonable for the purpose of the accounting test to be used in forecasting 2017 capital tracker expenditures. ATCO Electric is directed to reflect this 2017 union labour inflation rate in its compliance filing application to this decision.

99. For 2016 and 2017, ATCO Electric forecast contractor inflation rates to be two per cent and four per cent, respectively. ATCO Electric stated that the 2016 rate was based on the weakened economic conditions it had experienced in 2015, with the expectation that conditions would improve by 2017. As discussed above, with respect to the labour inflation rates, the Commission notes that since ATCO Electric filed its application, economic growth forecasts for 2016 and 2017 have decreased. While ATCO Electric indicated that it accounted for the downward trend in economic conditions in its 2016 contractor inflation forecast, the Commission finds that an adjustment to the 2017 forecast is required to reflect the most up to date information on the record. The Commission considers that a three per cent contractor inflation rate for 2017 is reasonable for the purpose of the accounting test to be used in forecasting 2016 and 2017 capital tracker expenditures, given that it is a mid-point between ATCO Electric's 2016 forecast and its 2017 forecasts and reflects the lower economic growth forecast¹⁰⁸ for 2017. ATCO Electric is directed to reflect this 2017 contractor inflation rate in its compliance filing application to this decision.

100. ATCO Electric applied for a 2.1 per cent increase in its "other" inflation rate based on Alberta CPI forecasts. The Commission notes that in the updated economic growth forecasts for 2016 and 2017, updated estimates of the CPI were also provided that are consistent with the forecasts provided in ATCO Electric's application. Accordingly, the Commission considers the 2016 and 2017 other inflation rates of 2.1 per cent to be reasonable, and these forecast rates are approved as filed.

6.1.1.2 Overhead allocations

101. ATCO Electric provided the following table, outlining its overhead allocation amounts based on capital funded by way of capital trackers and through the I-X mechanism:

¹⁰⁸ Exhibit 20555-X0052, undertaking response by Mr. McNabb to Mr. Wachowich, ATB Alberta Economic Outlook.

Table 7. ATCO Electric's 2012 to 2017 overhead allocation rates and totals¹⁰⁹

Year	2012 actual	2013 actual	2014 approved forecast	2014 actual	2015 update ¹¹⁰	2016 forecast	2017 forecast
Capital expenditures – non-capital trackers (\$ million)	285.0	258.6	283.7	270.0	274.8	227.9	234.9
Capital expenditures – non-capital trackers (\$ million)	21.1	36.6	45.9	56.5	54.6	66.9	66.0
Allocated overhead rate (%)	4.00	5.25	5.25	5.21	5.25	5.90	5.80
Allocated overhead – capital tracker (\$ million)	11.4	13.7	14.6	14.0	14.3	13.4	13.8
Allocated overhead – non- capital tracker (\$ million)	0.8	1.9	2.4	3.0	2.9	3.9	3.7
Total allocated overhead (\$ million)	12.2	15.6	17.0	17.0	17.2	17.3	17.5

102. ATCO Electric submitted that the allocated overhead increases from 2012 to 2014 were the result of growth in the capital full-time employee (FTE) labour complement caused by increases in the overall capital expenditures and decreased use of contractor construction crews. Furthermore, ATCO Electric explained that “since 2014, the forecast increase in allocated overhead costs has been limited to I-X.”¹¹¹

103. The costs that are included in ATCO Electric's overhead pool and descriptions of those costs were provided in its application. These costs are summarized in Table 8 of this decision:

Table 8. ATCO Electric's 2012 to 2017 allocated overhead pool costs¹¹²

Pool item	2012 actual	2013 actual	2014 approved forecast	2014 actual	2015 update ¹¹³	2016 forecast	2017 forecast
	(\$ million)						
HR and health, safety and environment	1.5	2.5	2.7	3.4	3.5	3.5	3.5
IT general and support	3.0	3.6	4.0	3.6	3.7	3.7	3.7
Supervision of capital program	2.3	2.6	2.8	3.2	3.2	3.2	3.3
Relocation	1.5	2.1	2.3	0.7	0.7	0.7	0.7
Administration and general	1.5	1.6	1.7	1.9	1.9	1.9	2.0
Rent and buildings	2.4	3.2	3.5	4.2	4.2	4.3	4.3
Total allocated overhead costs	12.2	15.6	17.0	17.0	17.2	17.3	17.5

¹⁰⁹ Exhibit 20555-X0007, application, paragraph 104.

¹¹⁰ ATCO Electric provided an update to the 2015 forecast capital overhead amounts that were approved in Decision 3218-D01-2015. The 2015 update amount is not subject to review in this proceeding. The 2015 actual overhead amounts will be brought forward in ATCO Electric's 2015 capital tracker true-up application.

¹¹¹ Exhibit 20555-X0007, application, paragraph 105.

¹¹² Exhibit 20555-X0007, application, paragraph 104.

¹¹³ ATCO Electric provided an update to the 2015 forecast capital overhead amounts that were approved in Decision 3218-D01-2015. The 2015 update amount is not subject to review in this proceeding. The 2015 actual overhead amounts will be brought forward in ATCO Electric's 2015 capital tracker true-up application.

104. ATCO Electric also included in the application the 2014 actual, and 2016 and 2017 forecast overhead allocated to each of its capital tracker programs.

105. In an IR response to the Commission, ATCO Electric provided variance explanations for the differences between the 2014 approved forecast and actuals for the allocated overhead cost pool items shown in Table 8 above. ATCO Electric noted that while there were variances in excess of I-X between the 2015 approved forecast costs for each allocated overhead pool item and the 2016 and 2017 forecasts, the total forecast allocated overhead costs for both 2016 and 2017 were similar to the 2015 approved forecast total escalated by I-X.¹¹⁴

106. Furthermore, ATCO Electric explained that with respect to the 2016 and 2017 forecast allocated overhead pool amounts, the explanations for “the variances between the 2014 approved forecast and the 2014 actual costs are consistent with the explanations for the forecast amounts for 2016 and 2017 that are in excess of I-X from the approved forecasts for 2014 and 2015.”¹¹⁵

107. ATCO Electric was also asked why its total allocated overhead forecast amounts for 2016 and 2017 were increasing given that its base capital expenditures in 2016 and 2017 were decreasing relative to the 2014 and 2015 expenditure amounts. In an IR response, ATCO Electric explained that its 2016 and 2017 allocated overhead amounts were increasing as a result of the forecast inflation applied to labour, contractor, and other costs included in the allocated overhead pool. Furthermore, the allocated overhead rates in 2016 and 2017, 5.90 and 5.80 per cent, respectively, are forecast to be higher than previous years given the decrease in capital expenditures expected in those years. However, ATCO Electric expects the rate will move closer to 5.25 per cent after 2017 as capital expenditures return to normal levels.¹¹⁶ ATCO Electric’s actual allocated overhead rate in 2013 and 2014 was 5.25 and 5.21 per cent, respectively, and the 2015 forecast allocated overhead rate was 5.25 per cent.

108. During the hearing, Mr. McNabb explained why ATCO Electric’s capital expenditures are forecast to decrease in 2016 and 2017, as compared to prior years, while the allocated overhead amounts for those year are expected to increase:

So there's a lot of discussion in the '13 to '15 proceeding on why our overhead was increasing, and it was due to from 2010 to '14, our capital program was increasing around 90 percent and our capital FTEs were increasing in a similar vein. And so as a result, we needed an increase in our allocated overhead to support the increase in the capital program and the capital FTEs. And by 2014 we had a forecast, I believe, of \$17 million for allocated overhead, and our actual allocated overhead came in at that amount.

And then thereafter, all we have done is for a forecast approach, is to increase the allocated overhead by I minus X through '15 to '17, and that's consistent with the direction from the AUC in Decision 3218. And, again, this is simply a forecast.

And I'll go further. And so one would ask, "Well, there's a slight drop in your capital program. Why isn't your allocated overhead dropping?" And, first of all, number one, it's a forecast. We're limited to I minus X, which the Commission stated was a reasonable approach. Number two, our capital program is only decreasing by about 10 percent over

¹¹⁴ Exhibit 20555-X0023, AE-AUC-2015JUL20-008.

¹¹⁵ Exhibit 20555-X0023, AE-AUC-2015JUL20-008.

¹¹⁶ Exhibit 20555-X0023, AE-AUC-2015JUL20-009.

those two years. It's not like it's decreasing by 50 percent. It does take a fair bit of time and effort to get these allocated overhead resources in place, so if there is a relatively small drop-off in your capital program, you don't want to be making significant reductions in your resources.

But the fourth thing I would note, and I think I did mention it earlier, either today or yesterday, this is a forecast. And to the extent we are able to find any synergies or what have you, that would be reflected in our actual allocated overhead in true-up.¹¹⁷

109. The CCA addressed ATCO Electric's 2016 and 2017 forecasts for allocated overhead in its written argument and stated that "forecasting costs to increase by I-X when construction levels are falling is not the test of a capital tracker. There needs to be some basis for the forecast. Simply stating that the costs are increasing by I-X is not sufficient."¹¹⁸ The CCA also stated it was concerned that during the hearing¹¹⁹ ATCO Electric was not able to provide its 2015 actual allocated overhead costs as a comparison to the 2014 actual costs, which in the CCA's view is an issue because, if ATCO Electric "does not know what its costs are they have no incentive to do anything to manage them since they do not know what they are managing."¹²⁰

110. Furthermore, the CCA provided an analysis of ATCO Electric's overhead rate and made note of the following. First, ATCO Electric's overhead costs increased by 28 and 9 per cent in 2013 and 2014, respectively. Second, the overhead cost increases in 2013 and 2014 form the basis for the 2015, 2016, and 2017 forecast overhead costs, which ATCO Electric inflated by I-X. Third, the average allocated overhead rate over the PBR term, based on ATCO Electric's forecasts, is 5.48 per cent, compared to the average overhead rate of 4.11 per cent, if 2012 actual overhead costs were inflated by I-X. Overall, the CCA recommended increases to the allocated overhead costs be limited to 2012 actual amounts escalated by I-X.¹²¹ In making this recommendation the CCA stated:

... [It] would only be a forecast for 2016 and 2017 and accordingly it should be okay. Secondly, the change would recognize that capital trackers should not simply be a reason to pile on overhead and abandon costs constraints and increase overhead 37%. Third, it would bring the incentives for capital trackers more in line with the rest of PBR.¹²²

111. The CCA also recommended that when ATCO Electric brings its actual allocated overhead costs during the capital tracker true-up proceedings, it should be required to provide detailed calculations of its overhead costs. This recommendation was based on the CCA's concern that ATCO Electric does not have an "allocation model which can demonstrate the costs are prudent."¹²³

112. ATCO Electric, in its reply argument, took issue with and responded to the CCA's statement that ATCO Electric does not manage or control its overhead costs. ATCO Electric stated that during the hearing, Mr. McNabb explained to Commission counsel why overhead

¹¹⁷ Transcript, Volume 2, page 310, line 13 to page 311, line 20 (Mr. McNabb).

¹¹⁸ Exhibit 20555-X0076, CCA argument, paragraph 27.

¹¹⁹ Transcript, Volume 1, page 70, line 5 to page 71, line 4.

¹²⁰ Exhibit 20555-X0076, CCA argument, paragraph 24.

¹²¹ Exhibit 20555-X0076, CCA argument, paragraphs 31-35.

¹²² Exhibit 20555-X0076, CCA argument, paragraph 36.

¹²³ Exhibit 20555-X0076, CCA argument, paragraph 37.

costs were not forecast to decrease in 2016 and 2017, in light of the decreases in capital expenditures.¹²⁴

113. Furthermore, in response to the CCA's recommendation that overhead costs be held to the level of the 2012 actuals escalated by I-X, ATCO Electric noted that the Commission previously approved its 2013 actual allocated overhead.¹²⁵

114. In its reply argument, the CCA referenced the correspondence submitted by the UCA on November 30, 2015,¹²⁶ that discussed employee layoffs within the ATCO Group, which includes ATCO Electric, and explained that it is concerned that the layoffs may affect capitalized overhead in areas such as human resources. The CCA's view was that this further supported its recommendation that overhead costs be held to 2012 actual levels escalated annually by I-X.¹²⁷

Commission findings

115. In Decision 3218-D01-2015, regarding ATCO Electric's 2013 actual overhead costs and 2014 and 2015 forecast overhead costs, the Commission gave the following direction:

555. The Commission directs ATCO Electric in future capital tracker applications, to provide and support its overhead costs in a similar manner to the information contained in ATCO Electric's IR responses and rebuttal evidence. The company must also be prepared to explain any significant year-over-year changes in the items that make up the overhead pool. To the extent that a company limits the year-over-year increases to an item in the overhead pool to I-X, the Commission considers that to be a reasonable approach for capital tracker purposes. However, the company is not required to limit its increases to its overhead items to I-X if it can demonstrate that an increase in excess of this amount, is prudent.¹²⁸

116. The Commission notes that the information ATCO Electric provided in support of its allocated overhead costs in that proceeding is similar to the information provided in the current application, as directed by the Commission. Furthermore, in Proceeding 3218, the CCA made a similar request to the one made in this proceeding that ATCO Electric provide additional calculations in support of its allocated overhead costs.¹²⁹ In Decision 3218-D01-2015, the Commission found that ATCO Electric was not required to provide any additional information.¹³⁰ Having reviewed the information ATCO Electric provided to support its overhead costs in this application, which is similar to that provided in Proceeding 3218, as directed, the Commission considers there to be sufficient evidence with respect to allocated overhead costs on the record of this proceeding. Accordingly, the Commission will not direct ATCO Electric to provide further supporting information for its allocated overhead costs.

117. Regarding the CCA's concern that ATCO Electric was unable to provide its 2015 actual allocated overhead costs, the Commission notes that 2015 actual costs related to capital trackers

¹²⁴ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 58.

¹²⁵ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 62.

¹²⁶ Exhibit 20555-X0077, UCA letter, November 30, 2015.

¹²⁷ Exhibit 20555-X0081, CCA reply argument, paragraph 68.

¹²⁸ Decision 3218-D01-2015, paragraph 555.

¹²⁹ Decision 3218-D01-2015, paragraph 550.

¹³⁰ Decision 3218-D01-2015, paragraph 554.

will be brought forward and the prudence of those costs will be assessed during the 2015 capital tracker true-up application.

118. In forecasting its 2016 and 2017 allocated overhead costs, ATCO Electric recognized that the 2016 and 2017 total overhead cost amounts are similar to the total 2015 approved overhead amount adjusted by I-X.¹³¹ Furthermore, ATCO Electric stated that this was consistent¹³² with the Commission's direction in Decision 3218-D01-2015 at paragraph 555. The Commission, however, notes that in paragraph 555 of Decision 3218-D01-2015, its direction was specific to limiting "the year-over-year increases to an item in the overhead pool to I-X," rather than increases in the total overhead amount being limited to I-X. In this regard, the Commission does not consider it reasonable for a utility to simply limit the total increase of its overhead costs to I-X, without explanation of any increases in excess of I-X for individual overhead pool items.

119. In response to a Commission IR, ATCO Electric provided an explanation of the increases in excess of I-X for individual overhead pool items.¹³³ The Commission has reviewed the information in support of ATCO Electric's 2014 actual overhead costs, including the variance explanations between the actuals and approved forecasts provided in its IR responses to the Commission, and finds that the 2014 actual overhead costs were prudent. Regarding the 2016 and 2017 forecast costs, while the Commission noted that ATCO Electric did not limit the increases to the overhead pool items to the 2015 approved forecast numbers escalated by I-X, ATCO Electric explained the variance in individual pool items in excess of I-X were consistent with the 2014 variances between the approved forecast and actuals. Mr. McNabb further confirmed this during the hearing¹³⁴ and provided an explanation of why there was a decrease in capital expenditures and an increase in forecast overhead costs. Accordingly, the Commission considers that ATCO Electric has sufficiently justified the overhead pool item forecast increases in excess of I-X for 2016 and 2017, and finds those costs to be reasonable on a forecast basis.

120. The Commission does not agree with the CCA that ATCO Electric's overhead costs should be limited to 2012 actuals escalated by I-X for the following reasons. ATCO Electric's 2013 actual overhead costs were previously approved by the Commission, as were its 2014 and 2015 forecast overhead costs. Furthermore, the Commission determined above that ATCO Electric had sufficiently demonstrated that its 2014 actual costs were prudent, and its 2016 and 2017 forecast costs are reasonable. In the absence of information on the record of this proceeding that the 2014 actual costs were not prudent and the 2016 and 2017 forecast costs are not reasonable, the Commission does not agree that ATCO Electric's overhead costs should be limited by the CCA's recommendation.

6.1.2 Affiliate transactions

121. In Decision 3558-D01-2015, which considered modifications to the minimum filing requirements for capital tracker applications, the Commission determined that identifying affiliate-related costs included in the forecast or actual costs of a proposed capital tracker project or program is useful in assessing those projects or programs. Accordingly, at paragraph 80 of Decision 3558-D01-2015, the Commission made the following direction:

¹³¹ Exhibit 20555-X0023, AE-AUC-2015JUL20-008.

¹³² Transcript, Volume 2, page 311, lines 1-2 (Mr. McNabb).

¹³³ Exhibit 20555-X0023, AE-AUC-2015JUL20-008.

¹³⁴ Transcript, Volume 2, page 307, lines 8-15 (Mr. McNabb).

80. ... the companies are directed to include in their business cases a summary of the services provided by or to an affiliate, the related costs and an explanation of how those amounts were determined.¹³⁵

122. To comply with this direction, in the application ATCO Electric detailed the services provided to or by its affiliates, including the costs of those services and the manner in which those costs were reflected in its capital tracker projects or programs. ATCO Electric provided the following table summarizing services provided by affiliates included in its capital tracker programs:

Table 9. ATCO Electric's affiliate services¹³⁶

Service	Affiliate	Period
Information technology (IT) services	ATCO I-Tek Inc (I-Tek)	To August 31, 2014
IT enhancements related to customer care and billing (CC&B) services	ATCO I-Tek Business Services (ITBS)	To December 31, 2014
Rental space	Canadian Utilities Limited (CU)	Ongoing

123. ATCO Electric explained that the provision of affiliate services by each of the affiliates to ATCO Electric, identified in the table above, is set out in separate Master Service Agreements (MSAs). ATCO Electric submitted that all transactions with affiliates are governed by the ATCO Group Inter-affiliate Code of Conduct, and that the costing of such transactions is also in accordance with the Code of Conduct.¹³⁷

124. ATCO Electric indicated that in addition to specific capital trackers that include affiliate services, affiliate services are included in the allocated overhead costs that are incorporated into each of the capital tracker programs. ATCO Electric explained that it did not itemize the affiliate costs included in the allocated overhead costs in each of the business cases; rather, ATCO Electric provided affiliate cost details separately in the application.¹³⁸ These affiliate cost details are described below.

125. With respect to IT services, in 2014, ATCO Electric noted that affiliate charges from I-Tek in regards to IT integration, application development and implementation were included in the following business cases:

Table 10. ATCO Electric's affiliate charges¹³⁹

Capital tracker reference	Affiliate charges – 2014 capital expenditures (\$ million)
C.2 IT Enterprise System Technology Upgrades	3.1
C.3 Industry Driven IT projects	0.4
L.1 Distribution automation	0.2

¹³⁵ Decision 3558-D01-2015, paragraph 80.

¹³⁶ Exhibit 20555-X0007, paragraph 94.

¹³⁷ Exhibit 20555-X0007, paragraph 95.

¹³⁸ Exhibit 20555-X0007, paragraph 95.

¹³⁹ Exhibit 20555-X0007, paragraph 96.

126. Additionally, in 2014, I-Tek charged ATCO Electric \$4.7 million for IT general and support services for capital personnel. Of this amount, ATCO Electric included \$2.1 million in the IT general and support component of the allocated overhead costs, as discussed in Section 6.1.1.2, and the remaining \$2.6 million, for personnel working directly on capital projects, in the applicable capital program.¹⁴⁰

127. ATCO Electric explained that it entered into an MSA with Wipro Solutions Canada Limited (Wipro) to obtain IT Services, effective September 1, 2014. For the period September 1, 2014 to December 31, 2014, IT Services pricing remained in accordance with the pricing provisions of the pre-existing IT MSA between ATCO Electric and I-Tek. However, effective January 1, 2015, IT Services pricing was governed under the MSA with Wipro. As a result, there are no affiliate transactions related to IT services for 2015 and beyond.¹⁴¹

128. Affiliate charges from I-Tek Business Services (ITBS) to ATCO Electric in 2014 for IT Enhancements related to CC&B were \$0.9 million and were allocated to the Industry Driven IT capital tracker projects. ATCO Electric terminated its MSA with ITBS as of December 31, 2014. All IT-related services previously provided by ITBS were provided to ATCO Electric in 2015 pursuant to the new MSA with Wipro, effective January 1, 2015. Therefore, there are no affiliate transactions forecast for IT enhancements related to CC&B services for 2015 and beyond.¹⁴²

129. In discussing rental space, ATCO Electric noted that it has sublease agreements in place with CU Limited for space in both ATCO Centre Edmonton and ATCO Centre Calgary. Costs associated with these sublease agreements are included in the allocated overhead costs. In 2014, \$2.0 million of rental charges related to capital staff and activities were included in the rent and buildings component of the allocated overhead costs. Rental charges from CU Limited included in the forecast allocated overhead costs are \$2.0 million for 2015 and \$2.1 million for 2016 and 2017, respectively.¹⁴³

130. ATCO Electric noted that in ATCO Electric Transmission's 2015-2017 GTA, ATCO Electric Transmission requested confirmation from the Commission that the general exemption for transactions between the transmission and the distribution functions granted by the Alberta Energy and Utilities Board, the predecessor of the AUC, in Decision 2004-054¹⁴⁴ is no longer required. ATCO Electric submitted that, for the purpose of responding to the direction at paragraph 80 of Decision 3558-D01-2015, the transmission function will be identified as an affiliate of the distribution function once confirmation is received from the Commission that it is appropriate for the transmission function and the distribution function to operate as separate affiliates.¹⁴⁵

¹⁴⁰ Exhibit 20555-X0007, paragraph 97.

¹⁴¹ Exhibit 20555-X0007, paragraph 98.

¹⁴² Exhibit 20555-X0007, paragraphs 99-100.

¹⁴³ Exhibit 20555-X0007, paragraph 10.

¹⁴⁴ Decision 2004-054: ATCO Electric Ltd., Code of Conduct Exemptions, Application 1317784-1, File 1110-3, July 28, 2004.

¹⁴⁵ Exhibit 20555-X0007, paragraph 102. The Commission notes that in ATCO Electric Transmission's 2015-2017 GTA (Proceeding 20272), on February 23, 2016, ATCO Electric Transmission filed a revised application and, as evident in Exhibit 20272-X1099, titled "Attachment 1 - Revised Application Narrative – Blackline," on PDF pages 12-13, ATCO Electric Transmission has withdrawn its request for "removal of all Affiliate Code exemptions that were previously approved by the AUC for transactions between the Transmission and Distribution divisions of ATCO Electric."

Commission findings

131. The Commission has reviewed ATCO Electric's disclosure of its affiliate transactions relating to its capital tracker projects or programs in light of the direction given at paragraph 80 of Decision 3558-D01-2015. The Commission finds that ATCO Electric provided sufficient detail relating to the costs of affiliate transactions allocated to its capital tracker projects or programs in its application and project business cases. The Commission also notes that ATCO Electric has entered into a new MSA with Wipro commencing January 1, 2015, and the Commission is reviewing the terms and conditions of IT services provided under the Wipro MSA in a separate proceeding (Proceeding 20514).

132. Accordingly, the Commission finds that ATCO Electric has complied with the direction set out at paragraph 80 of Decision 3558-D01-2015.

6.1.3 Controls and accountability

133. At paragraph 520 of Decision 3218-D01-2015, the Commission stated:

520. ... The Commission considers that formal project management policies and procedures are necessary to ensure the Commission understands that the scope, level, timing and costs of forecast capital projects are reasonable and actual costs have been prudently incurred. The Commission directs Fortis to describe fully its formal project management policies and procedures in its next capital tracker application.

134. ATCO Electric described its project management policies and procedures, which it used to ensure that costs are reasonable and prudent for its capital tracker projects or programs. ATCO Electric explained that its processes and procedures are applied uniformly across all capital projects or programs to ensure that the needs of the project or program are met and all costs are prudently incurred.¹⁴⁶ For simple and high volume projects or programs, ATCO Electric submitted that the processes, practices, and controls are applied fairly consistently, while for the larger and more complex projects or programs, increased rigor is generally applied.¹⁴⁷

135. ATCO Electric explained that a Professional Practice Management Plan (PPMP) governs ATCO Electric's engineering practices in relation to planning, design, project management, procurement, construction, operations, safety, and asset management of distribution systems. ATCO Electric also indicated that it applies principles of project management consistent with the Project Management Institute (PMI) methodology in the Project Management Body of Knowledge (PMBOK) guide.¹⁴⁸

136. ATCO Electric detailed the following processes relating to its project management phases, i.e., initiation, planning, executing, monitoring and control, and closure. In addition to providing a process overview by process group, ATCO Electric provided a more detailed description of project management areas that apply broadly across all capital projects, including scope management, schedule management, cost management, cost control, risk management, procurement management and process management. ATCO Electric included a project

¹⁴⁶ Exhibit 20555-X0007, paragraph 34.

¹⁴⁷ Exhibit 20555-X0007, paragraph 38.

¹⁴⁸ Exhibit 20555-X0007, paragraphs 36-37.

management overview flowchart outlining the process groups and project management areas which have formal project management processes and practices.¹⁴⁹

137. In argument, the CCA submitted that, based on a discussion at the oral hearing between the CCA counsel and ATCO Electric, it was not clear if the customer would be responsible for the incremental costs of an accelerated in-service date, or whether ATCO Electric had controls in place to ensure agreed-to in-service dates are not unreasonable. The CCA recommended that ATCO Electric be directed to provide, in its next capital tracker application, the mechanisms and controls it has in place to prevent unrealistic customer project in-service dates.¹⁵⁰

138. In reply argument, ATCO Electric refuted the CCA's recommendation, and submitted that contrary to the CCA's suggestion that "customers dictate the in-service dates or that ATCO Electric is a passive bystander in the discussions," project schedules are managed throughout the project and discussions occur between ATCO Electric and its customers, to determine the project scope, in-service date and costs.¹⁵¹

Commission findings

139. The Commission has reviewed ATCO Electric's project management policies and procedures in light of the directions given at paragraph 520 of Decision 3218-D01-2015. The Commission finds that ATCO Electric provided a sufficient explanation of its controls and accountability procedures with respect to the initiation, planning, design, execution and review of its capital projects. Accordingly, the Commission finds that ATCO Electric has complied with the direction set out at paragraph 520 of Decision 3218-D01-2015. The Commission directs ATCO Electric to confirm that these policies and procedures continue to be in place and to advise the Commission of improvements and modifications to these policies and procedures in future capital tracker applications.

140. The Commission has reviewed the record regarding the CCA's issue of third-party risk with respect to approval delays, including the testimony of ATCO Electric's witness, Mr. Claude on the topic. During the hearing, Mr. Claude explained that ATCO Electric "follow[s] a change control process where there are changes in scope, schedule or cost. We would work very closely with the customer to determine who would bear the costs of the change. If the cost is something that is driven by the customers, the customers would typically bear that cost. If it's a cost that is something that is driven through ATCO Electric, ATCO Electric would bear that cost."¹⁵² When asked by the CCA's counsel if consumers pay for the difference as a result of a variance, Mr. Claude responded, "[i]n this circumstance where there are delays, ATCO Electric would be accountable to pick up that cost, and it is through that process and the process that we use consistently on all our projects where our estimates do get refined through the course of the project, and we would true-up on actuals."¹⁵³

141. The Commission considers that the testimony provided, adequately addresses the CCA's concern, regarding in-service dates and how incremental costs with respect to a capital project or program would be addressed. ATCO Electric submitted that it monitors the delays and costs,

¹⁴⁹ Exhibit 20555-X0007, Figure 1, page 25.

¹⁵⁰ Exhibit 20555-X0076, CCA argument, paragraphs 45-46.

¹⁵¹ Exhibit 20555-X0080, ATCO Electric reply argument, paragraphs 74-76.

¹⁵² Transcript, Volume 1, page 139, lines 3-10.

¹⁵³ Transcript, Volume 1, page 140, lines 1-6.

which would be trued-up to actuals, and it also monitors in-service dates, which are to a certain extent driven by third parties. Generally, ATCO Electric's position as to whether the customer would be responsible for the incremental costs of an accelerated in-service date, and whether ATCO Electric had controls in place to ensure agreed-to in-service dates, has been explained on the record.

6.2 Previously approved capital tracker projects or programs

142. This section deals with ATCO Electric's projects or programs that were approved for capital tracker treatment on an actual or forecast basis in Decision 3218-D01-2015. It considers these projects or programs in the context of the true-up of 2014 actual expenditures and, if they are proposed to continue in 2016 and 2017, this section also considers the 2016 and 2017 forecasts.

6.2.1 Projects or programs for which no objections were raised

143. In the application, there were a number of previously approved capital tracker projects or programs for which no objections were raised by the parties to this proceeding regarding need, scope, level, timing or costs. Table 11 summarizes these projects and shows the 2014 actual capital expenditures on which the 2014 capital tracker true-up is based, the 2015 forecast capital additions approved in Decision 3218-D01-2015 and updated by ATCO Electric in this application, as well as the 2016 and 2017 forecast capital additions proposed in the application.

Table 11. Projects or programs for which no issues were raised

Program or project name (business case appendix no.)	Capital additions (\$ million)				
	2014 actual	2015		2016 forecast	2017 forecast
		approved	update		
Transportation Equipment Appendix B Part 2, Project Update E.1	10.7	13.0	12.5	11.0	12.2
Third-Party Driven Relocations Appendix B Part 2, Project Update F.1, F.2, F.4, F.6, F.7, F.8	14.5	9.5	9.4	8.7	8.3
New Extensions Appendix B Part 2, Project Update G.1	101.6	96.4	96.4	82.4	91.7
Overhead Line Rebuilds, Replacements and Life Extension Appendix B Part 2, Project Update H.1, H.4	20.9	23.3	22.6	16.8	18.4
Wood Pole Replacements and Life Extension Appendix B Part 3, Project Update I.1	32.4	27.4	25.4	26.2	27.1
Reliability Appendix B Part 3, Project Update J.1, J.3 – J.10	10.6	9.0	6.6	6.3	4.1
Wildfire Risk Reduction Appendix B Part 3, Project Update K.1	14.8	13.3	13.6	14.3	14.4

144. The Transportation Equipment program is an annual recurring program, and consists of the lifecycle replacement of vehicles and mobile equipment that are at the end of their useful lives, equipment refurbishments, and the addition of new equipment to support new staff.¹⁵⁴

¹⁵⁴ Exhibit 20555-X0007, application, paragraph 31, Table 3.2-1.

The need for this program as part of the project assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015¹⁵⁵ for 2013, 2014 and 2015.

145. The 2014 approved forecast capital additions for the Transportation Equipment program were \$12.8 million, while the actual 2014 capital additions were \$10.7 million, resulting in a negative \$2.1 million variance. ATCO Electric provided a table showing the 2014 actual and forecast expenditures by equipment type, which included both positive and negative variances. The reasons listed by ATCO Electric to explain the variances were 22 trucks were added to the fleet instead of the 34 trucks originally forecast, 12 more vehicles were replaced earlier than expected, a highway tractor and a forklift were purchased to facilitate moving materials, and 10 vehicles were deferred to later years.¹⁵⁶

146. Of the 12 more vehicles replaced earlier than expected, eight trucks were replaced due to engine failures and two trucks had been involved in accidents or required body repairs. In response to a Commission IR, ATCO Electric submitted that it would have been imprudent to repair the units because the repair costs estimated at greater than \$6,000 would have exceeded the vehicles' value.¹⁵⁷ During the hearing in discussion with Commission counsel, Mr. Howell, on behalf of ATCO Electric, explained that the manufacturer's warranty period also plays a role in the decision to buy a new truck rather than repairing it.¹⁵⁸

147. With respect to the highway tractor purchase, ATCO Electric submitted that the highway tractor was required to ensure on-time material and equipment shipments, and in addition resulted in an estimated yearly cost savings of \$105,476, attributed to the use of an internal operator rather than an external provider.¹⁵⁹ ATCO Electric submitted that the forklift purchase was required for "more efficient movement and storage of materials required for construction and maintenance projects as well as emergency response to restore customer interruptions" and "safer and more effective handling of large equipment," and in addition resulted in a one-time cost savings of \$211,000.¹⁶⁰

148. The forecast capital additions for the Transportation Equipment program for 2016 and 2017 are \$11.0 million and \$12.2 million, respectively. ATCO Electric provided tables showing the 2016 and 2017 forecast additions and replacements by equipment type,¹⁶¹ and explained that additions are "constantly adjusted to match associated manpower additions", and replacements are "based on current assessments of the condition of existing vehicles."¹⁶²

149. The Third-Party Driven Relocations program consists of a number of separate projects where ATCO Electric is relocating or rebuilding distribution facilities at the request of a third party. The relocation or rebuilding of these facilities may be required due to road widenings, municipal developments, or changes in land use. The need for this program as part of the project

¹⁵⁵ Decision 3218-D01-2015, paragraphs 286 and 289.

¹⁵⁶ Exhibit 20555-X0004, Project Update E.1, Appendix C, page 1.

¹⁵⁷ Exhibit 20555-X0023, AE-AUC-2015JUL20-037(a).

¹⁵⁸ Transcript, Volume 3, page 461, line 19 to page 462, line 17 (Mr. Howell).

¹⁵⁹ Exhibit 20555-X0023, AE-AUC-2015JUL20-037(b) and the business case attached as AE-AUC-2015JUL20-037(b) Attachment 1.

¹⁶⁰ Exhibit 20555-X0023, AE-AUC-2015JUL20-037(e) and the business case attached as AE-AUC-2015JUL20-037(e) Attachment 1.

¹⁶¹ Exhibit 20555-X0004, Project Update E.1, Appendix C, pages 2-3, tables C-2 and C-3.

¹⁶² Exhibit 20555-X0004, Project Update E.1, Appendix C, page 2.

assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015¹⁶³ for 2013, 2014 and 2015.

150. The 2014 approved forecast capital additions for the Third-Party Driven Relocations program, net of customer contributions, were \$15.9 million, while the actual 2014 capital additions were \$14.5 million, resulting in a negative \$1.4 million variance. The variance consisted of an \$800,000 increase in small Third-Party Driven Relocation projects, which are projects with individual forecasts less than \$500,000, an increase of \$200,000 related to the Highway 43 Twinning project, and an increase of \$0.9 million related to the Township Road 560 Feeder Relocation project, which was not included in ATCO Electric's 2014 forecast. Those increases were offset by a \$2.6 million decrease in the Highway 63 distribution line moves project, a \$200,000 decrease in the Guy Rural Line Relocation project, and a \$500,000 decrease in the Canadian National Railway crossing conversion project.¹⁶⁴ For the small Third-Party Driven Relocation projects, ATCO Electric provided a list of projects and their actual expenditures for 2014.¹⁶⁵ In addition, business case updates were provided for each of the projects included in ATCO Electric's variance explanation in support of the 2014 actual capital additions.¹⁶⁶

151. The forecast capital additions for the Third-Party Driven Relocations program, net of customer contributions, for 2016 and 2017 are \$8.7 million and \$8.3 million, respectively.¹⁶⁷ ATCO Electric explained that it is not aware of the projects completed under this program in advance of the forecast years, given that the projects are initiated through third-party requests or patrol-identified issues. As a result, the forecast costs for this program are based on a three-year average of historical actual expenditures that have been escalated for 2016 and 2017.¹⁶⁸

152. The New Extensions program is composed of small projects (Small New Extensions) below \$1.0 million, and larger individual projects (Large New Extensions), that are required to connect new customers and upgrade existing services in ATCO Electric's service area. The need for this program as part of project assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015¹⁶⁹ for 2013, 2014 and 2015.

153. The 2014 approved forecast capital additions, net of customer contributions, for the Small New Extensions projects were \$88.2 million, while the actual 2014 capital additions were \$89.2 million, resulting in a positive \$1.0 million variance. The 2014 approved forecast capital additions, net of customer contributions, for the Large New Extensions projects were \$17.5 million, while the actual 2014 capital additions were \$12.4 million, resulting in a negative \$5.1 million variance. ATCO Electric explained that the variance for the Large New Extensions projects was due to a delay in service dates for four projects to 2015, and to five large projects that dropped beneath the \$1.0 million threshold that were moved to the Small New Extensions project category.¹⁷⁰

¹⁶³ Decision 3218-D01-2015, paragraph 318.

¹⁶⁴ Exhibit 20555-X0004, Project Update F, Table 2.

¹⁶⁵ Exhibit 20555-X0004, Project Update F.1, Appendix D.

¹⁶⁶ Exhibit 20555-X0004, project updates F.2 to F.8.

¹⁶⁷ Exhibit 20555-X0004, Project Update F, Appendix B, page 1.

¹⁶⁸ Exhibit 20555-X0004, Project Update F, Appendix C, page 2.

¹⁶⁹ Decision 3218-D01-2015, paragraphs 328 and 332.

¹⁷⁰ Transcript, Volume 3, page 509, line 13 to page 510, line 2 (Mr. Claude).

154. The forecast capital additions net of customer contributions for the Small New Extensions projects for 2016 and 2017 are \$90.9 million and \$100.8 million, respectively.¹⁷¹ The forecast for Small New Extensions projects was based on a forecast of new customer connections and an average cost per connection by customer class. ATCO Electric explained that the number of new customer connections was developed through ongoing dialogue and consultation with key customer groups, developers and municipal authorities. ATCO Electric submitted that the forecast reflects key economic indicators for Alberta, including expected oil and gas development. ATCO Electric further explained that the average cost per connection was based on the previous years' history, adjusted each year for inflation.¹⁷²

155. The forecast capital additions, net of customer contributions for the Large New Extensions projects for 2016 and 2017 are \$21.0 million and \$23.0 million, respectively.¹⁷³ For these larger, more complex projects, ATCO Electric explained that an economic analysis is completed to identify the least cost alternative, and the best solution is selected in discussion with the customer.¹⁷⁴ ATCO Electric provided a description and cost breakdown for each large new extension project in Appendix F of its Project Update G.1.

156. During the hearing, in discussion with Commission counsel regarding ATCO Electric's confidence in its forecast, considering the current state of the economy in Alberta, ATCO Electric confirmed that the forecast for the New Extensions program reflected its expectation that there will be a reduction in planned new extensions in 2016, and submitted that the forecast is "still quite accurate under the circumstance."¹⁷⁵

157. The Overhead Line Rebuilds, Replacements and Life Extension program consists of work to replace deteriorated and damaged overhead lines and the associated components based on failure and test results. This program is composed of an annual, recurring component, and specific overhead line projects.¹⁷⁶ The need for this program as part of project assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015¹⁷⁷ for 2013, 2014 and 2015.

158. The 2014 approved forecast capital additions for this program were \$21.1 million, while the actual 2014 capital additions were \$20.9 million, resulting in a negative \$0.2 million variance in capital additions.¹⁷⁸ For 2014, ATCO Electric had forecast the annual, recurring component of the Overhead Line Rebuilds, Replacements and Life Extension program, as well as the 4160 V System Rebuild Town of Drumheller project and the 5L114 Wabasca 720S Rebuild project. The forecast and actual 2014 costs for the annual component, which is composed of the replacement of ground rods, street lights, transformers and equipment, switches insulators, and small overhead line rebuild projects, are summarized below:

¹⁷¹ Exhibit 20555-X0004, Project Update G.1, Appendix D, page 3.

¹⁷² Exhibit 20555-X0004, Project Update G.1, Appendix D, pages 1-2.

¹⁷³ Exhibit 20555-X0004, Project Update G.1, Appendix E, pages 2-3.

¹⁷⁴ Exhibit 20555-X0004, Project Update G.1, Appendix E, page 1.

¹⁷⁵ Transcript, Volume 3, page 512, line 19 to page 513, line 17 (Mr. Claude).

¹⁷⁶ Exhibit 20555-X0004, Project Update H, page 1.

¹⁷⁷ Decision 3218-D01-2015, paragraphs 368 and 372.

¹⁷⁸ Exhibit 20555-X0004, Project Update H preamble, page 2, Table 2.

Table 12. 2014 Overhead Line Rebuilds, Replacements and Life Extension annual component costs¹⁷⁹

Description	2014 forecast costs	2014 actual costs
	(\$ million)	
Ground and anchor rod replacement	1.7	1.9
Street lights	1.7	1.2
Transformers and equipment	6.9	7.5
Switches insulators	3.5	3.1
Small overhead line rebuild projects	3.0	3.5
Total capital expenditures	16.7	17.1
Opening construction work in progress (CWIP) balance	2.8	2.8
Closing CWIP balance	1.5	0.5
Customer contributions	-	0.64
Total capital additions (net of contributions)	18.0	18.7

159. For each item within the Overhead Line Rebuilds, Replacements and Life Extension program annual component, ATCO Electric provided a business case project update that included 2014 variance explanations based on unit costs and the number of units replaced. Furthermore, for the small overhead line rebuild projects, which are projects less than \$500,000, ATCO Electric provided a list of actual projects completed in 2014 and applicable unit costs for each project.¹⁸⁰ The remainder of the 2014 program variance was the result of the 4160 V System Rebuild Town of Drumheller project having 2014 actual capital additions of \$2.1 million, compared to a forecast of \$3.1 million. The negative \$1.0 million variance was due to ATCO Electric not having to replace all the waterproof conductors in Drumheller, as originally forecast.¹⁸¹ Finally, there was a \$0.1 million capital addition associated with the 5L114 Wabasca 720S Rebuild project that was not forecast, which is a 2015 forecast project, due to a section of conductor requiring replacement in 2014.¹⁸²

160. The forecast capital additions for this program for 2016 and 2017 are \$16.8 million and \$18.4 million, respectively.¹⁸³ There were no large Overhead Line Rebuild, Replacements and Life Extension program projects forecast for 2016 and 2017 identified at the time of ATCO Electric's IR responses.¹⁸⁴ The 2016 and 2017 costs for the annual component of the Overhead Line Rebuild, Replacements and Life Extension program, which make up the total program forecast costs, are based on the following:

¹⁷⁹ Exhibit 20555-X0004, Project Update H.1, tables B-2 and C-2.

¹⁸⁰ Exhibit 20555-X0023, AE-AUC-2015JUL20-049, Attachment 1.

¹⁸¹ Exhibit 20555-X0004, Project Update H.1, Appendix B, page 2.

¹⁸² Exhibit 20555-X0004, Project Update H, page 2.

¹⁸³ Exhibit 20555-X0004, Project Update H, page 2.

¹⁸⁴ Exhibit 20555-X0023, AE-AUC-2015JUL20-050.

Table 13. 2016 and 2017 Overhead Line Rebuilds, Replacements and Life Extension program forecast costs¹⁸⁵

Description	2016 forecast costs	2017 forecast costs	Forecast method
	(\$ million)		
Ground and anchor rod replacement	1.1	1.5	Based on actual ground rod test failures and 3-year historical average unit cost. ¹⁸⁶
Street lights replacement	1.2	1.9	Based on actual davit test failures and 3-year historical average unit cost. ¹⁸⁷
Transformers and equipment replacement	7.2	7.5	Based on a 3-year historical average of project costs. ¹⁸⁸
Switches insulators	3.8	3.9	Based on 2014 actual costs given that 2013 was the first year for this component and had a higher unit cost. ¹⁸⁹
Small overhead line rebuild projects	3.5	3.6	Based on a 3-year historical average of project costs. ¹⁹⁰
Total capital expenditures	16.8	18.4	

161. The Wood Pole Replacements and Life Extension program is an annual recurring program, and consists of the replacement or life extension of deteriorated or damaged wood poles, as required based on failures and test results.¹⁹¹ The need for this program as part of project assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015¹⁹² for 2013, 2014 and 2015.

162. The 2014 approved forecast capital additions for this program were \$23.4 million, while the actual 2014 capital additions were \$32.4 million, resulting in a positive \$9.0 million variance in capital additions.¹⁹³ ATCO Electric provided the following table of 2014 forecast and actual quantities and capital expenditures to assist in its variance explanations:

¹⁸⁵ Exhibit 20555-X0004, Project Update H.1, Appendix C, page1, Table C-1.

¹⁸⁶ Exhibit 20555-X0004, Project Update H.1, Appendix D, page 2.

¹⁸⁷ Exhibit 20555-X0004, Project Update H.1, Appendix E, page 2.

¹⁸⁸ Exhibit 20555-X0004, Project Update H.1, Appendix F, page 2.

¹⁸⁹ Exhibit 20555-X0004, Project Update H.1, Appendix G, page 2.

¹⁹⁰ Exhibit 20555-X0004, Project Update H.1, Appendix H, page 2.

¹⁹¹ Exhibit 20555-X0007, application, paragraph 31, Table 3.2-1.

¹⁹² Decision 3218-D01-2015, paragraphs 392 and 395.

¹⁹³ Exhibit 20555-X0003, Project Update I.1, Appendix B, page 1.

Table 14. 2014 Wood Pole Replacements and Life Extension total project true-up costs¹⁹⁴

Pole replacements	2014 forecast	2014 actual	Variance
Replace quantity	3,700	4,214	13.9%
Replace unit rate (\$)	5,300	6,465	22.0%
Pole replacement (\$ million)	19.6	27.2	38.8%
Capital life extension			
Test quantity	92,228	112,926	22.4%
Capital life extension unit rate (\$)	35.7	33.6	(5.9%)
Capital life extension (\$ million)	3.3	3.8	15.2%
Total capital expenditures (\$ million)	22.9	31.0	35.4%

163. ATCO Electric explained that pole replacement quantities were higher than expected due to more one-off miscellaneous or emergency pole replacements and the requirement to add additional poles to reduce the distance between poles (re-spanning) to meet current stricter Canadian Standards Association (CSA) standards. ATCO Electric explained that the replacement unit rate variance was attributed to the higher unit replacement cost of replacing poles on an emergency basis, re-spanning, and additional costs incurred to complete the Swan Hills pole replacement project. ATCO Electric further explained that difficult terrain, requirements for off road equipment, limited access, and live line construction to limit oil field outages increased the unit cost for the Swan Hills project.¹⁹⁵ For life extension of poles, ATCO Electric explained that more poles were tested and treated for life extension than originally forecast, albeit at an average unit rate that was less than forecast.¹⁹⁶

164. The forecast capital additions for this program for 2016 and 2017 are \$26.2 million and \$27.1 million, respectively.¹⁹⁷ To forecast the unit rates for the Wood Pole Replacements and Life Extension program, ATCO Electric used the average of its 2012 to 2014 historical actual unit cost per pole, then escalated the result to forecast its 2016 and 2017 capital expenditures. The forecast excluded the high unit cost associated with the Swan Hills project.¹⁹⁸ The number of poles were forecast using historical pole test program failure rate results. ATCO Electric submitted that achieving an outstanding pole replacement balance of 8,845 poles at the end of 2017 is optimal.¹⁹⁹ ATCO Electric provided the following table, showing its forecast quantities and expenditures for 2016 and 2017 that are required to achieve this balance, as set out in Table 15:

¹⁹⁴ Exhibit 20555-X0003, Project Update I.1, Appendix C, page 2, Table C-2.

¹⁹⁵ Exhibit 20555-X0003, Project Update I.1, Appendix C, page 3.

¹⁹⁶ Exhibit 20555-X0003, Project Update I.1, Appendix C, page 2.

¹⁹⁷ Exhibit 20555-X0003, Project Update I.1, Appendix B, page 1.

¹⁹⁸ Exhibit 20555-X0003, Project Update I.1, Appendix C, page 3.

¹⁹⁹ Exhibit 20555-X0003, Project Update I.1, Appendix D, page 1.

Table 15. 2012 to 2017 Wood Pole Replacements and Life Extension actual and forecast capital expenditures net of contribution²⁰⁰

	2012	2013	2014	2015 update	2016 forecast	2017 forecast
Replace quantity	4,285	6,423	4,214	3,943	3,944	3,944
Replace unit rate (\$)	5,694	4,671	6,465	5,697	5,855	6,059
Pole replacement (\$ million)	24.4	30.0	27.2	22.5	23.1	\$23.9
Test quantity (from Appendix E)	53,368	64,927	112,926	79,695	79,759	80,979
Capital life extension unit rate (\$)	37.48	35.42	33.61	37.36	38.39	39.73
Capital life extension (\$ million)	2.0	2.3	3.8	3.0	3.1	3.2
Total capital expenditures (\$ million)	26.4	32.3	31.0	25.4	26.2	27.1

165. The Reliability program is comprised of a group of small projects, each below \$0.5 million, and larger individual projects, which are necessary to improve reliability and power quality on segments of the distribution system that have a history of below-average performance. The need for this program as part of project assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015²⁰¹ for 2013, 2014 and 2015.

166. The 2014 approved forecast capital additions for this project were \$10.6 million, while the actual 2014 capital additions were \$10.6 million. ATCO Electric explained that the variances for the small projects and larger individual projects were within their respective estimation accuracy. The table below shows the variances attributable to each project under the Reliability program:

Table 16. 2014 Reliability program forecast and actual capital additions²⁰²

Project description	2014 forecast	2014 actual
	(\$ million)	
J.1 – Small Projects – Reliability Improvements	2.0	2.2
J.3 – 5L359 Swan Hills Reliability Improvements	1.1	1.3
J.5 – 5L349 Trochu Reliability Improvements	3.6	3.2
J.6 – 5L216 Jasper Reliability Improvements	3.8	3.9
TOTAL	10.6	10.6

167. The forecast capital additions for this project for 2016 and 2017 are \$6.3 million and \$4.1 million, respectively. The forecast for the small projects was developed based on the average of actual annual expenditures for the previous three years, escalated by a blended forecast inflation rate for 2016 and 2017 of 2.76 per cent and 3.49 per cent, respectively. The blended rates were calculated using the weighting of labour, contractor and other costs for 2013

²⁰⁰ Exhibit 20555-X0003, Project Update I.1, Appendix C, page 1, Table C-1.

²⁰¹ Decision 3218-D01-2015, paragraphs 428 and 432.

²⁰² Exhibit 20555-X0003, J. Reliability Program Preamble, page 2, Table 2.

and 2014 actual expenditures and applying the respective weightings to the inflation assumptions proposed in the application,²⁰³ as set out in Table 17 below.

Table 17. Reliability program – Calculation of blended escalation rate for small projects²⁰⁴

	2016			2017		
	Inflation rate per Section 3.4 of the application	Weighting based on 2013 and 2014 actual expenditures	Calculation of blended rate	Inflation rate per Section 3.4 of the application	Weighting based on 2013 and 2014 actual expenditures	Calculation of blended rate
	(A)	(B)	(A x B)	(A)	(B)	(A x B)
Labour	3.75%	42.2%	1.58%	3.75%	42.2%	1.58%
Contractor	2.00%	36.7%	0.73%	4.00%	36.7%	1.47%
Other	2.10%	21.1%	0.44%	2.10%	21.1%	0.44%
Blended Rate			2.76%			3.49%

168. The forecasts for the individual projects were estimated based on factors specific to each project. The table below shows the forecast costs for each project under the Reliability program:

Table 18. 2016 and 2017 Reliability program forecast capital additions²⁰⁵

Project description	2016 forecast	2017 forecast
	(\$ million)	
J.1 – Small Projects – Reliability Improvements	2.2	2.2
J.7 – City of Grande Prairie – 4160 V System Reliability	1.4	
J.8 – Hanna Area Reliability Improvements	2.0	
J.9 – MacDonald Island Alternate Feed	0.7	
J.10 – Spirit River Area Reliability Improvements		1.9
TOTAL	6.3	4.1

169. The Wildfire Risk Reduction program consists of the work that is required by ATCO Electric to minimize wildfires caused by power lines under the Agreement for the Reduction and Prevention of Wildfires in the Forest Protection Area (Wildfire Agreement) with Alberta Environment and Sustainable Resource Development (ESRD). The work completed under this program involves removing vegetation along power lines in high-risk areas that are identified by ATCO Electric and ESRD.²⁰⁶ Specifically, there are three program areas which are completed as part of the Wildfire Risk Reduction program: Hazard Tree Identification, which consists of removing a small number of trees that are at risk of contact with power lines; Tree-Free programs, which involve widening the right-of-way around a power line by removing all trees in an area; and FireSmart Community-Based Wildfire Risk Reduction, which consists of removing vegetation surrounding power lines specifically to protect communities from wildfires.²⁰⁷

²⁰³ Exhibit 20555-X0023, AE-AUC-2015JUL20-052.

²⁰⁴ Exhibit 20555-X0066, undertaking 16.

²⁰⁵ Exhibit 20555-X0003, J. Reliability Program Preamble, page 2, Table 2.

²⁰⁶ Exhibit 20555-X0003, Project Update K, page 1.

²⁰⁷ Exhibit 20555-X0003, Project Update K, page 1.

The need for this program as part of project assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015²⁰⁸ for 2013, 2014 and 2015.

170. The 2014 approved forecast capital additions for this project were \$15.2 million, while the actual 2014 capital additions were \$14.8 million, resulting in a negative \$0.4 million variance. The variance was due to a slight increase in the amount of work completed, as shown in Table 19, as compared to what was forecast. This was offset by a smaller 2014 CWIP opening balance than ATCO Electric had forecast, which resulted in fewer capital additions.²⁰⁹ ATCO Electric provided the following table outlining its 2014 actual work and capital expenditures:

Table 19. 2013 to 2017 forecast and actuals for the Wildfire Risk Reduction program²¹⁰

Year	Hazard Tree program		Tree-Free program		FireSmart program				Total cost (\$ million)
	Trees removed	Cost (\$ million)	Hectares cleared	Cost (\$ million)	Trees removed	Cost (\$ million)	Hectares cleared	Cost (\$ million)	
2013 actual	29,235	4.5	147	4.7	1,314	0.2	31	1.0	10.4
2014 forecast	30,126	4.6	162	5.1	3,100	0.5	88	2.8	13.0
2014 actual	45,618	6.9	80	2.5	4,533	0.7	90	3.0	13.1
2015 forecast	48,082	7.6	101	3.1	2,416	0.4	78	2.5	13.6
2016 forecast	48,116	8.1	151	4.9	2,372	0.4	30	1.0	14.3
2017 forecast	49,575	8.2	159	5.0	3,123	0.5	24	0.8	14.4

171. ATCO Electric also provided the associated unit costs per tree removal and unit cost per hectare cleared for each of the activities identified in the table above. The forecast capital additions for this project for 2016 and 2017 are \$14.3 million and \$14.4 million, respectively.²¹¹ The forecast for the Wildfire Risk Reduction program was based on ATCO Electric's expectation for the amount of work required in 2016 and 2017. ATCO Electric explained that the amount of work completed under each of the three Wildfire Risk Reduction programs can depend on the amount of work completed in another.²¹² Furthermore, ATCO Electric explained that a more aggressive trend in lowering the risk of wildfires has led to an increase in the forecast number of trees removed, which is laid out in its annual wildfire mitigation plan agreed to by ESRD, as required by the Wildfire Agreement.²¹³

Commission findings

172. In Decision 3218-D01-2015, the Commission approved the need on an actual or forecast basis, for each of the projects or programs listed in Table 11 above, for the purposes of capital tracker treatment in one or more of 2013, 2014 or 2015. Further, the Commission determined that the proposed scope, level, timing and forecast costs for these projects and programs were

²⁰⁸ Decision 3218-D01-2015, paragraph 123. Note: In Decision 3218-D01-2015, the Wildfire Risk Reduction program was referred to as the "Wildfire Mitigation program."

²⁰⁹ Exhibit 20555-X0003, Project Update K.1, pages 1-1, tables B-2 and C-1.

²¹⁰ Exhibit 20555-X0004, Project Update K.1, Appendix C, page 1, Table C-1.

²¹¹ Exhibit 20555-X0004, Project Update K.1, Appendix C, page 1, Table C-1.

²¹² Exhibit 20555-X0023, AE-AUC-2015JUL20-059(d).

²¹³ Transcript, Volume 3, page 520, line 2 to page 521, line 17.

reasonable. Therefore, the Commission has previously determined that each of the projects or programs listed in Table 11 above satisfied the project assessment requirement of capital tracker Criterion 1 in one or more previous years. In addition, in Decision 3218-D01-2015 and the related compliance filing Decision 20369-D01-2015, the Commission approved the actual scope, level, timing and costs of projects and programs included in the 2013 capital tracker true-up application, as prudent.

173. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that any of the projects or programs listed in Table 11 was not required in 2014.

174. With respect to the scope, level and timing of the each of the projects or programs listed in Table 11 and carried out in 2014, the Commission has reviewed ATCO Electric's 2014 actual capital additions associated with each of these projects or programs and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for these capital trackers and approved in Decision 3218-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for each of these projects or programs in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

175. In the present application, ATCO Electric requested capital tracker treatment for these projects or programs on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that any of the projects or programs listed in Table 11 are not required to continue in 2016 or 2017.

176. With respect to the scope, level and timing of each of the projects or programs listed in Table 11 for 2016 and 2017, the Commission has reviewed the business cases and the relevant portions of the record for each of these projects or programs and finds the forecast scope, level and timing of each of these projects or programs for 2016 and 2017 to be reasonable. The Commission has reviewed the information supporting ATCO Electric's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable based on the respective forecasting methodologies employed, as described earlier in this section, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision.

177. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the projects or programs listed in Table 11 above are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, subject to these adjustments and directions, the

Commission finds that each of these projects or programs satisfies the project assessment requirement of Criterion 1 for 2016 and 2017.

6.2.2 Distribution to Transmission Contributions

178. The Distribution to Transmission Contributions program consists of the annual contributions that ATCO Electric is required to make for transmission projects that directly relate to transmission system access in its distribution service territory. The contribution amounts are set in accordance with the AESO's Terms and Conditions of Service.²¹⁴ The need for this program as part of project assessment under capital tracker Criterion 1 was approved by the Commission in Decision 3218-D01-2015 for 2014 and 2015.²¹⁵ ATCO Electric provided a business case in support of this program for its 2014 actuals, and 2016 and 2017 forecast in Appendix B Part 1 to its application.

179. The high-level process for identifying and approving projects that are classified under this program is as follows: ATCO Electric identifies a distribution deficiency which requires a transmission system solution and prepares a distribution deficiency report (DDR); the AESO reviews the DDR, and submits a needs identification document (NID) to the Commission for approval; and the AESO then determines the contribution amount ATCO Electric is required to pay through a customer contribution decision (CCD). The contribution amount that ATCO Electric pays to the AESO is calculated using a formula provided by the AESO.²¹⁶

180. The 2014 approved forecast capital additions for the Distribution to Transmission Contributions program were \$17.51 million, while the actual 2014 capital additions were \$12.1 million, resulting in a negative \$5.4 million variance. ATCO Electric provided a table in its business case, reproduced below, that showed the variance breakdown, by project, for this program in 2014, and explained that the negative variance was primarily due to a \$3.8 million decrease in capital additions related to two projects, for which the commissioning dates were delayed from 2014 to 2015.²¹⁷ The remainder of the variance was the result of a number of projects having final CCD amounts lower than forecast, partially offset by projects with a higher than forecast CCD final amount.

²¹⁴ Exhibit 20555-X0005, Project Update A.1, executive summary, page 1.

²¹⁵ Decision 3218-D01-2015, paragraph 443.

²¹⁶ Transcript, Volume 3, page 503, lines 12-21.

²¹⁷ Exhibit 20555-X0005, Project Update A.1, Appendix B, page 1.

Table 20. 2014 Distribution to Transmission Contributions program forecast and actual capital additions²¹⁸

Project	2014 forecast	2014 actual	Variance	Variance explanation
(\$ million)				
Buchanan Creek Substation	8.74	7.53	-1.21	Change in AESO investment levels and in project actual costs
Ksituan River Voltage Regulator & 25kV Breaker Addition	0.29	0.18	-0.11	Change in project costs
Edith Lake Transformer Addition	-0.29	-0.28	0.01	Final cost true-up
Swan River Transformer Replacement	0	-0.07	0.07	Final cost true-up
Mercer Hill Breaker Addition	0.95	0	-0.95	In service later than forecast
Dog Rib New POD	0.90	1.16	0.26	Increased cost to add AMR equipment
Monitor Substation Capacity Upgrade	2.83	0	-2.83	In service later than forecast
Irish Creek 706S Substation Upgrade	4.09	3.60	-0.49	Change in project costs
Total	17.5	12.1	-5.4	

181. The forecast capital additions for the Distribution to Transmission Contributions program for 2016 and 2017 are \$16.4 million and \$36.2 million, respectively. ATCO Electric provided tables for each of 2016 and 2017, that set out the forecast capital additions by project, including the actual and expected dates of the DDRs and NIDs.²¹⁹ The difference in forecast capital additions between 2016 and 2017 is due to the number of projects each year, with three expected in 2016 and five in 2017. The forecasts for each project within the Distribution to Transmission Contribution program are based on the DDRs, NIDs, and CCDs.²²⁰ ATCO Electric provided copies of those documents available at the time it filed its application, in the appendices to its business case.²²¹

182. In an undertaking response, ATCO Electric provided a NID for the Thorton 2091S project²²² and CCDs for the Thorton 2091S and Mowat 2033S projects,²²³ which were not available when ATCO Electric filed its application. Both the Thorton 2091S project and the Mowat 2033S project have estimated in-service dates of 2016, and had forecast capital additions of \$7.6 and \$5.89 million, respectively, when ATCO Electric filed its application.²²⁴

183. Neither the UCA nor the CCA raised an issue with the Distribution to Transmission Contributions program in their respective arguments and reply arguments.

²¹⁸ Exhibit 20555-X0005, Project Update A.1, Appendix B page 2, Table B-3.

²¹⁹ Exhibit 20555-X0005, Project Update A.1, Appendix C, pages 2-3, tables C-1 and C-2.

²²⁰ Exhibit 20555-X0005, Project Update A.1, Appendix C, page 1.

²²¹ Exhibit 20555-X0005, Project Update A.1, appendices D, E, F and G.

²²² Exhibit 20555-X0059, undertaking response by Mr. Sveinbjornson to Mr. Marriott at Transcript, Volume 2, page 216, lines 4-5.

²²³ Exhibit 20555-X0060, undertaking response by Mr. Sveinbjornson to Mr. Marriott at Transcript, Volume 2, page 217, lines 8-9.

²²⁴ Exhibit 20555-X0005, Project Update A.1, Appendix C, page 2, Table C-1.

Commission findings

184. In Decision 3218-D01-2015, the Commission approved the need for the Distribution to Transmission Contributions program for purposes of capital tracker treatment for 2014 and 2015. Further, the Commission determined the forecast scope, level, timing and costs for the program for 2014 and 2015 to be reasonable. Therefore, the Commission has previously determined that this program satisfied the project assessment requirement of Criterion 1.²²⁵

185. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Distribution to Transmission Contributions program was not required in 2014.

186. With respect to the scope, level and timing of this program carried out in 2014, the Commission has reviewed ATCO Electric's 2014 actual capital additions associated with this program and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for this capital tracker and approved by the Commission in Decision 3218-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this program in light of the evidence supporting these costs and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

187. In the present application, ATCO Electric also requested capital tracker treatment for this program on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that this program is not required to continue in 2016 or 2017.

188. With respect to the scope, level and timing of this program for 2016 and 2017, the Commission has reviewed the updated business case and the relevant portions of the record for this program and finds the forecast scope, level and timing of this program for 2016 and 2017 to be reasonable. ATCO Electric's forecast capital additions associated with the Distribution to Transmission Contributions program are \$16.4 million in 2016 and \$36.2 million in 2017. During the hearing, ATCO Electric provided CCDs for the Thorton 2091S and Mowat 2033S projects, which were not available when the application was filed, in an undertaking response. The Commission considers that in assessing the reasonableness of the forecast capital additions for the Distribution to Transmission Contributions program, the Commission requires the most recent cost information available. Accordingly, in its compliance filing to this decision, the Commission directs ATCO Electric to use the updated CCD amounts in calculating the K factor for this program.

189. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing for the Distribution to Transmission Contributions

²²⁵ Decision 3218-D01-2015, paragraph 447.

program are reasonable as proposed for 2016 and 2017. However, given the direction above, the Commission is making no finding with respect to ATCO Electric's forecast costs for 2016 and 2017 at this time.

6.2.3 Buildings, Structures and Leasehold Improvements

190. ATCO Electric described the Buildings, Structures and Leasehold Improvements program as required to provide office and warehouse facilities to meet ATCO Electric's current staffing needs and near-term forecast additions of personnel and equipment.²²⁶

191. The 2014 approved forecast capital additions for this program were \$24.1 million, while the actual 2014 capital additions were \$25.2 million. The forecast capital additions for this program for 2016 and 2017 were \$22.6 million and \$31.4 million, respectively. Within this program, ATCO Electric provided a smaller grouping of related items as miscellaneous buildings, structures and leaseholds along with individual building projects. The net capital additions related to this program from 2014 to 2017 are as follows:

Table 21. 2014 to 2017 Buildings, Structures and Leasehold Improvements program net capital additions²²⁷

Project description	Net capital additions (\$ million)					
	2014 approved	2014 actual	2015 approved	2015 update	2016 forecast	2017 forecast
B.1 – Miscellaneous Buildings, Structures and Leaseholds	4.8	5.6	2.1	3.0	2.1	1.8
B.2 – Drumheller Service Building	18.8	16.1	17.9	18.7	-	-
B.3 – Nisku Pole and Training Facility Development	-	3.0	-	-	-	-
B.4 – Valleyview Service Building	0.5	0.5	-	0.1	-	-
B.5 – Fort McMurray North Service Building	-	-	-	-	20.5	0.6
B.6 – High Level Service Building	-	-	-	-	-	24.3
B.7 – Fox Creek Service Building	-	-	-	-	-	4.7
Total	24.1	25.2	20.0	21.8	22.6	31.4

192. Regarding the prudence of its actual 2014 capital additions, ATCO Electric confirmed that the 2014 expenditures for this program were managed in accordance with its formal project management policies and procedures, as described in the application, and further submitted that the 2014 capital additions “were reasonably and prudently incurred in the provision of safe and reliable electrical distribution service.”²²⁸

193. In Decision 2013-435, the Commission noted at paragraph 407:

407. While the project assessment set out in Section 3.1.4 will generally be applied at the level of an approved grouping of projects, the Commission will, where necessary,

²²⁶ Exhibit 20555-X0004, Appendix B – Part 2, B. Buildings, Structures & Leasehold Improvements Program Preamble, page 1.

²²⁷ Exhibit 20555-X0004, Appendix B – Part 2, B. Buildings, Structures & Leasehold Improvements Program Preamble, page 2, Table 2.

²²⁸ Exhibit 20555-X0004, Appendix B – Part 2, B. Buildings, Structures & Leasehold Improvements Program Preamble, pages 2-3.

consider the individual component projects comprising the approved groupings in order to assess the need for the capital expenditures and the reasonableness of the forecast costs.

194. The Commission considers it is necessary in assessing the projects in the Buildings, Structures and Leasehold Improvements program to review separately each of the projects listed in Table 21 above with respect to the project assessment requirement of Criterion 1.

6.2.3.1 Miscellaneous Buildings, Structures and Leaseholds

195. The Miscellaneous Buildings, Structures and Leaseholds project is an annual recurring project comprised of a number of small projects, and is required to complete building improvements to owned and leased space in order to reduce overcrowding of existing staff and equipment, meet new building codes and requirements for safety, provide building and site security and preserve the lives of existing facilities.²²⁹ The need for this project as part of the project assessment under capital tracker Criterion 1 was approved by the Commission in Decision 3218-D01-2015²³⁰ for 2013, 2014 and 2015.

196. The 2014 approved forecast capital additions for the Miscellaneous Buildings, Structures and Leaseholds project were \$4.8 million, while the actual 2014 capital additions were \$5.6 million, resulting in a positive \$0.8 million variance.²³¹ The following table sets out the variance breakdown by small projects in 2014.

Table 22. 2014 Miscellaneous Buildings, Structures and Leaseholds project variance to forecast costs²³²

2014 True-Up						
	Capital Expenditures			Capital Additions		
	2014 forecast	2014 actual	Variance (over)/under	2014 forecast	2014 actual	Variance (over)/under
	(\$ million)					
1 Miscellaneous Renovations and Capital Improvements	2.2	2.0	0.2	2.5	2.4	0.1
2 Closed Storage Structures	1.6	1.3	0.3	2.2	1.9	0.3
3 Employee Housing	0.1	-	(0.1)	0.1	-	(0.1)
4 Grande Prairie Regional Building	-	0.2	(0.2)	-	0.2	(0.2)
5 Lloydminster Regional Building	-	0.6	(0.6)	-	0.6	(0.6)
6 Nisku Old Panel Shop Renovation	-	0.2	(0.2)	-	0.5	(0.5)
7 Total	\$3.9	\$4.3	(0.4)	\$4.8	\$5.6	(0.8)
8 Variance			(10%)			(17%)

²²⁹ Exhibit 20555-X0004, Appendix B – Part 2, Business Case B.1, page 1.

²³⁰ Decision 3218-D01-2015, paragraphs 140 and 143.

²³¹ Exhibit 20555-X0004, Appendix B – Part 2, tables B-1 and B-2, PDF page 11.

²³² Exhibit 20555-X0004, Appendix B – Part 2, Table C-2, PDF page 12.

197. ATCO Electric explained that the positive variance primarily resulted from a \$0.6 million increase in capital additions related to the Lloydminster Regional Building, due to the construction of the communication tower, which was delayed from 2013, and due to capital additions of \$0.5 million for the Nisku Old Panel Shop Renovation project, which was not identified at the time ATCO Electric filed its application in Proceeding 3218. The remainder of the variance was a result of a number of projects having slightly higher capital additions than forecast, which were partially offset by projects with slightly lower capital additions than forecast. ATCO Electric stated that these variances were “within the Type 3 estimate accuracy of +/-10% and the Rule 005 variance reporting threshold.”²³³

198. The forecast capital additions for the Miscellaneous Buildings, Structures and Leaseholds project for 2016 and 2017 are \$2.05 million and \$1.79 million, respectively.²³⁴ In its business case, ATCO Electric provided tables for each of 2016 and 2017, with details of the forecast capital expenditures for each project, including brief descriptions of each project.²³⁵ ATCO Electric explained that due to variability in location, building size, age and complexity of building systems, and the unique scope of work within each project, the estimated costs could not be compared to other projects completed in prior years. Rather, ATCO Electric based costs on successful tender contracts with vendors.²³⁶

199. ATCO Electric submitted that the scope, nature and drivers for the Miscellaneous Building, Structures and Leaseholds Improvements project in years 2016 and 2017 have not changed since its approval by the Commission in Decision 3218-D01-2015 for 2013, 2014 and 2015.²³⁷

200. In response to a UCA concern regarding identical in-service dates for every project, ATCO Electric clarified that while all in-service dates identified in tables C-3 and C-4 of the Business Case B.1 for Miscellaneous Buildings, Structures and Leaseholds were identified as December of the respective year, these projects are completed at various times throughout the year, depending on priority and scheduling.²³⁸ Further, ATCO Electric confirmed that it has applied mid-year return and depreciation in the K factor calculation for all capital tracker programs for 2016 and 2017, including the Miscellaneous Buildings, Structures and Leaseholds project, as per the Commission’s direction in Decision 2012-237. ATCO Electric further explained that depreciation for 2016 and 2017 will be trued up to the actual expense for each year.²³⁹

201. Regarding the communication tower erected for the Lloydminster Regional Building project (project 5 in Table 22 above), ATCO Electric confirmed that this project was filed in Proceeding 650 at a forecast cost of \$0.4 million, and was approved by the Commission in Decision 2011-134,²⁴⁰ paragraph 224. ATCO Electric explained that the erection of the

²³³ Exhibit 20555-X0004, Appendix B – Part 2, Business Case B.1, Appendix C, pages 1-2.

²³⁴ Exhibit 20555-X0004, Appendix B – Part 2, Table B-1, PDF page 11.

²³⁵ Exhibit 20555-X0004, Appendix B – Part 2, Business Case B.1, Appendix C, tables C-3 and C-4, PDF pages 14-15.

²³⁶ Exhibit 20555-X0039, Business case B.1, page 5.

²³⁷ Exhibit 20555-X0004, Appendix B – Part 2, PDF page 6.

²³⁸ Exhibit 20555-X0021, AE-UCA-2015JUL20-010 (a).

²³⁹ Exhibit 20555-X0021, AE-UCA-2015JUL20-010 (b)-(c).

²⁴⁰ Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Proceeding 650, Application 1606228-1, April 13, 2011 at paragraph 224.

communication tower was delayed and the actual cost was \$0.2 million higher than forecast due to changes from the original design and location of the tower to account for an underground water storage tank conflicting with the original footing placements.²⁴¹

202. In response to a Commission IR, ATCO Electric explained the renovations done as part of the Nisku Old Panel Shop Renovation project were a result of the transmission function relocating to a separate facility, and two distribution function workgroups moving into the vacated space.²⁴²

Commission findings

203. In Decision 3218-D01-2015, the Commission approved the need on an actual or forecast basis for the Miscellaneous Buildings, Structures and Leaseholds project, for purposes of capital tracker treatment for 2013, 2014 and 2015. Further, the Commission determined the actual scope, level, timing and costs for this project in 2013 to be prudent, and the forecast scope, level, timing and costs for 2014 and 2015 to be reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1.²⁴³

204. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Miscellaneous Buildings, Structures and Leaseholds project was not required in 2014.

205. With respect to the scope, level and timing of this project carried out in 2014, the Commission has reviewed ATCO Electric's 2014 actual capital additions associated with this project and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for this capital tracker and approved by the Commission in Decision 3218-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

206. In the present application, ATCO Electric also requested capital tracker treatment for this project on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Miscellaneous Buildings, Structures and Leaseholds project is not required to continue in 2016 or 2017.

²⁴¹ Exhibit 20555-X0021, AE-UCA-2015JUL20-011(a)-(d).

²⁴² Exhibit 20555-X0023, AE-AUC-2015JUL20-028.

²⁴³ Decision 3218-D01-2015, paragraphs 140 and 143.

207. With respect to the scope, level and timing of each of the previously approved projects for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for the Miscellaneous Buildings, Structures and Leaseholds project and finds the forecast scope, level and timing of this project for 2016 and 2017 to be reasonable. ATCO Electric's forecast capital additions associated with Miscellaneous Buildings, Structures and Leaseholds project are \$2.05 million in 2016 and \$1.79 million in 2017. The Commission has reviewed the information supporting ATCO Electric's 2016 and 2017 forecasts and finds the total annual cost forecasts to be reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision.

208. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Miscellaneous Buildings, Structures and Leaseholds project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

6.2.3.2 Drumheller Service Building

209. In Proceeding 3218, ATCO Electric proposed the construction of a new 54,050 square foot (sq. ft.) service building in Drumheller, Alberta, at an estimated capital cost of \$37.0 million. This project was executed in two phases with Phase 1 being completed by December 2014 and Phase 2 to be completed by December 2015.²⁴⁴ ATCO Electric provided an update to its business case, originally filed in Proceeding 3218, in Appendix B Part 2, Project Update B.2.²⁴⁵

210. The Commission made the following findings in Decision 3218-D01-2015:

168. In Decision 2013-358, the Commission approved the need for an earlier iteration of the project, including the proposed combined facility, with costs forecast at \$30.08 million based on a building with an area of 50,014 square feet to serve the distribution function. Based on its review of the business case and other evidence on the record of this proceeding, the Commission finds that the business drivers for the project, upon which the Commission based its approval in Decision 2013-358,^[246] still remain valid, and that the project is required to prevent deterioration in service quality and safety. The Commission accepts ATCO Electric's explanation for the project delays, which are the result of factors primarily outside of its ability to control. The Commission is not persuaded however, based on the evidence, that the scope of project approved in Decision 2013-358 required a further 4,000 sq. ft. addition and why that scope increase resulted in an additional \$7 million in forecast costs.

169. In the absence of sufficient evidence in support of the increase in scope and costs, ATCO Electric cannot be said to have satisfied the onus to demonstrate that the entire scope of the project, as applied for in this application, satisfies the project assessment requirements of Criterion 1. As a result, the Commission denies capital

²⁴⁴ Exhibit 20555-X0004, PDF page 20.

²⁴⁵ Exhibit 20555-X0004, PDF page 19.

²⁴⁶ Decision 2013-358: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Proceeding 1989, Application 1608610-1, September 24, 2013.

tracker treatment at this time for the additional \$7 million in forecast costs associated with the Drumheller project.

170. While the Commission is denying capital tracker treatment for the additional \$7 million in forecast capital costs associated with the Drumheller project at this time, the Commission notes the statement made at paragraph 48 of Decision 2013-435, that a company may apply for capital tracker treatment of capital expenditures after the capital additions are made. Consequently, ATCO Electric may reapply for capital tracker treatment of the additional \$7 million in capital costs associated with the expanded scope of this project, once it has incurred all the capital expenditures associated with this project. Any such application would require evidence supporting the need for the greater scope and the prudence of the costs incurred.

211. In this application, ATCO Electric clarified that the construction of Phase 2, which will be completed in 201, will result in a greater total building area of 58,555 sq. ft. at a cost of \$34.9 million. The change in the total building size from 54,050 sq. ft. to 58,555 sq. ft. is required to accommodate an additional 1.5 shop bays.²⁴⁷

212. ATCO Electric confirmed that the scope, nature and drivers for the Drumheller Service Building have not changed since its application in Proceeding 3218 for 2014 and 2015.²⁴⁸ In keeping with the direction given by the Commission in Decision 3218-D01-2015, ATCO Electric applied for a true-up of actual costs of \$16.1 million incurred in 2014, pertaining to the costs of construction for Phase 1, comprising 22,593 sq. ft. of the total building area, which has been completed and is occupied by the distribution function. The costs for Phase 2, which will be completed in 2015, result from an increase to the total building area from 54,050 sq. ft. to 58,555 sq. ft. and will be submitted by ATCO Electric in the 2015 true-up proceeding. ATCO Electric also noted that it will be able to provide the final allocation of costs relating to the distribution function's share of the total costs at that time.²⁴⁹

213. ATCO Electric provided a breakdown of its actual costs in Appendix B of its business case.²⁵⁰ The 2014 forecast capital additions for this project were \$18.9 million, while the actual 2014 capital additions were \$16.1 million, resulting in a \$2.8 million negative variance. ATCO Electric explained the lower actual costs were a result of savings in 2014 in relation to earthwork and an architectural redesign of Phase 2.²⁵¹

214. By increasing the building size, ATCO Electric indicated it is able to share the facility with ATCO Electric Transmission in 2015. ATCO Electric planned to have the distribution function's personnel occupy approximately 51,000 sq. ft. at an allocated cost of roughly \$30.4 million (in 2014 and 2015 dollars) of the total project costs of \$34.9 million. As Mr. Howell, on behalf of ATCO Electric, explained during the hearing:

... We're still playing with the exact space allocations. But roughly we're back down to the 51,000 square foot range and the \$30.4 million, which is very close to what was approved in Proceeding 1989.²⁵²

²⁴⁷ Exhibit 20555-X0044, PDF page 4.

²⁴⁸ Exhibit 20555-X0004, PDF page 20.

²⁴⁹ Exhibit 20555-X0075, ATCO Electric argument, paragraph 46.

²⁵⁰ Exhibit 2055-X0004, PDF page 28.

²⁵¹ Exhibit 2055-X0004, PDF page 29.

²⁵² Transcript, Volume 4, page 637, lines 1-5.

215. ATCO Electric also stated that it “... fully accepts that upon the true up for Phase 2, all Drumheller project costs and space, including any allocation to Transmission and the resultant effects if any upon any amounts added in 2014, should be within scope for that review.”²⁵³

216. ATCO Electric noted that the increase of 4,000 sq. ft. applied for in Proceeding 3218 was not the sole contributor to the increase in projected costs from \$30.1 million to the forecast of \$37.6 million. ATCO Electric also attributed the difference to the fact that the estimate approved by the Commission in Decision 2013-358 for the Drumheller building was based on preliminary design costs and were not yet fully tendered costs. ATCO Electric submitted that approximately \$1.7 million can be associated with the increased scope and the 4,000 sq. ft. expansion.²⁵⁴

217. ATCO Electric added that the 4,000 sq. ft. was required for an additional bay to store equipment and material, and for a group of distribution technologists, which was a new workgroup not identified at the time of design development. Additionally, ATCO Electric explained that three mechanics bays were increased by approximately 400 sq. ft. each, to allow for safer work areas around tools, equipment and vehicles. A mezzanine was also added for material storage for various workgroups, which can be converted to work space for near term growth.²⁵⁵

218. For clarity, ATCO Electric provided the following table, showing the change in the scope of the Drumheller Service Building since it was first submitted in Proceeding 1989²⁵⁶ (subsequently approved by the Commission in Decision 2013-358) and as applied for in this application, also noting the changes in cost and the difference in the allocation of costs between the distribution and transmission functions. ATCO Electric reiterated that it will reflect the actual occupancy and cost for the distribution function’s share of the total building in the 2015 true-up application.²⁵⁷ The forecast allocation used in the following table is an estimate to reflect the distribution function’s projected share at 87 per cent.

²⁵³ Exhibit 20555-X0075, ATCO Electric argument, paragraph 53.

²⁵⁴ Exhibit 20555-X0023, AE-AUC-2015JUL20-030.

²⁵⁵ Exhibit 20555-X0023, AE-AUC-2015JUL20-030.

²⁵⁶ ATCO Electric 2013-2014 Transmission GTA.

²⁵⁷ Exhibit 20555-X0080, ATCO Electric Reply Argument, paragraph 39.

Table 23. Changes in the scope of the Drumheller service building²⁵⁸

	Allocation of area (ft ²)			Allocation of cost (\$ million)		
	AED	AET	Total	AED	AET	Total
Proceeding 1989						
Drumheller Service Building	50,000	12,500	62,500	30.1	7.5	37.6
Changes Identified in 3218						
Exclusion of Transmission	-	(12,500)	(12,500)	-	(7.5)	(7.5)
AE-AUC-2015JUL20-030 Distribution Technologists	2,000	-	2,000	0.9	-	0.9
AE-AUC-2015JUL20-030 Mechanic Bays	1,300	-	1,300	0.6	-	0.6
AE-AUC-2015JUL20-030 Mezzanine	700	-	700	0.3	-	0.3
Subtotal 3218	4,000	(12,500)	(8,500)	1.7	(7.5)	(5.8)
Total as per Proceeding 3218	54,000	-	54,000			
Changes Identified in 20555						
Transmission - Shop	-	4,000	4,000	-	-	-
Transmission - Office	-	1,400	1,400	-	-	-
Distribution Engineering	(900)	-	(900)	-	-	-
Allocation of common space to Transmission	(2,100)	2,100	-	-	-	-
Subtotal 20555	(3,000)	7,500	4,500	(1.4)	4.5	3.1
Total as per Proceeding 20555	51,000	7,500	58,500	30.4	4.5	34.9

219. The UCA in its argument, stated that Mr. Howell appeared to confirm at the oral hearing that ATCO Electric was applying for capital tracker treatment for the entire cost of the Drumheller Service Building, including the additional 4,000 sq. ft. denied by the Commission in Decision 3218-D01-2015.²⁵⁹ The UCA argued that ATCO Electric has provided no new evidence to demonstrate the need for the additional 4,000 sq. ft. beyond the information in the business cases provided in Proceeding 3218. Given the direction by the Commission in Decision 3218-D01-2015, the UCA recommended that the inclusion of the additional \$1.74 million as a capital tracker should be denied.²⁶⁰

220. In its reply argument, ATCO Electric reiterated that it is only seeking approval of the 2014 true-up cost of \$16.1 million for the 22,593 sq. ft. associated with Phase 1 of the Drumheller Service Centre, which is now complete and in use solely by the distribution function.²⁶¹

Commission findings

221. In Decision 2013-358, the Commission approved the need for the Drumheller Service Building with costs forecast at \$30.08 million, based on a building with an area of 50,014 sq. ft.

²⁵⁸ Exhibit 20555-X0063, Undertaking 9.

²⁵⁹ Exhibit 20555-X0074, UCA argument, paragraph 62.

²⁶⁰ Exhibit 20555-X0074, UCA argument, paragraph 65.

²⁶¹ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 40.

for ATCO Electric's distribution function. In Decision 3218-D01-2015, the Commission reaffirmed that the Drumheller Service Building is required to prevent deterioration in service quality and safety. However, the Commission also found that there was not enough evidence on the record to conclude that the expanded scope of the project, as applied for in Proceeding 3218, and which included an additional 4,000 sq. ft., satisfied the project assessment requirements of Criterion 1. Consequently, the Commission denied capital tracker treatment for the costs associated with the additional 4,000 sq. ft.²⁶²

222. In this application, ATCO Electric is applying for the true-up of the actual \$16.1 million of costs incurred in 2014, pertaining to the construction for Phase 1, comprising 22,593 sq. ft. of the total building area, which has been completed and is occupied by the distribution function.

223. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Drumheller Service Building project was not required in 2014.

224. With respect to the scope, level and timing of the actual capital additions associated with Phase 1 of this project in 2014, the Commission finds that they are generally consistent with the scope, level and timing of the work outlined in the business case and approved by the Commission in Decision 3218-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

225. However, the Commission is not making a finding with respect to the costs associated with Phase 2 of the project, which could potentially include space beyond the approved area of 50,014 sq. ft., but is expected to be closer to the area approved by the Commission for the Drumheller Service Building in Decision 2013-358 and Decision 3218-D01-2015.²⁶³ The Commission will review the Phase 2 costs including the final allocation of space between the transmission and distribution function and the resultant effects if any upon any amounts added in 2014, in the 2015 true-up proceeding. In its 2015 true-up, ATCO Electric is directed to address any differences in the final area and costs from those approved by the Commission in Decision 2013-358 and Decision 3218-D01-2015. ATCO Electric is also directed to provide an explanation for differences in the final allocation of space between its distribution and transmission functions from the allocations approved by the Commission in Decision 2013-358.

6.2.3.3 Nisku Pole and Training Facility Development

226. The Nisku Distribution Service Centre (NDSC) facility is a warehousing facility which contains a training pole yard and an underground lab used by all staff, especially by line and technical staff. The NDSC project was proposed as a capital tracker in Proceeding 3218. The project entailed the purchase of land for the facility at the Leduc Business Park; the planning, design, building construction, and relocation of the training pole yard and underground lab to the new facility; and the repurposing of the former training pole yard and underground lab yard

²⁶² Decision 3218-D01-2015, paragraph 168.

²⁶³ Transcript, Volume 4, page 637, lines 1-5.

vacated at the NDSC for large distribution material staging and material storage.²⁶⁴ ATCO Electric provided an update to its business case, originally filed in Proceeding 3218, in Appendix B Part 2, Project Update B.3.²⁶⁵

227. In Decision 3218-D01-2015, the Commission found that the project was necessary to maintain service reliability and safety at adequate levels during 2013 and in 2014:

183. The Commission has reviewed the business case provided by ATCO Electric and the evidence on the record with respect to the Nisku pole and training facility development project, particularly ATCO Electric's response to AUC-AE-30, where it explained the reasons for its forecast growth projections and the need for additional material laydown and staging, and considers that the evidence provided by ATCO Electric supports a finding that the various functional elements of the project were required to maintain service reliability and safety at adequate levels during 2013. Further, based on the record of this proceeding, the functional elements of the project remains necessary in 2014. However, the method of delivery of the training function has not been demonstrated to the satisfaction of the Commission.

228. However, the Commission denied capital tracker treatment for the training facility component of the project due to a finding of insufficient evidence to satisfy the requirements of Criterion 1:

184. ... All of the alternatives presented in ATCO Electric's business case were premised on the company providing all of the required training itself, using company facilities, personnel and equipment. The business case explored different physical facility possibilities of how the company would provide this training itself, namely whether to: acquire or build a separate warehouse for Large Distribution projects; purchase, lease lands adjacent to the NDSC; and, purchase non-adjacent lands to the NDSC. All of these alternatives started with the assumption that ATCO Electric needs to own and operate its own training facility. The evidence discloses that ATCO Electric did not fully consider whether other potentially reasonable alternatives outside of the company, such as third-party providers or joint ventures with other utilities or public institutions, were reasonable.

185. The Commission finds that ATCO Electric did not consider potentially reasonable alternatives when it formed its business case, such as forming a joint venture with NAIT, or cooperating with other utilities to build a shared facility in order to provide training to its technicians at the lowest cost possible ...

186. In the case of the training centre, the Commission would expect the business case to provide a cost-benefit analysis or other qualitative or quantitative studies that considers the alternatives in meeting the identified need that might be reasonable, and demonstrates that the company has selected the most cost-effective option.

187. Based on the above, the Commission finds that there is insufficient evidence on the record to demonstrate that the actual scope, level, timing and costs of the training facility component of the Nisku Pole and Training Facility Development project in 2013 were prudent, or that the forecast scope, level, timing and costs for 2014 are reasonable. Accordingly, without such evidence the Commission is unable to determine if the

²⁶⁴ Exhibit 20555-X0004, PDF page 32.

²⁶⁵ Exhibit 20555-X0004, PDF page 31.

training facility component of the Nisku pole and training facility development satisfies the requirements of Criterion 1. Therefore, the capital costs of the training facility component of the project is denied capital tracker treatment at this time. In reaching this finding, the Commission is not making a determination on the prudence of the 2013 costs incurred in respect of the training facility component of the project.

229. ATCO Electric explained that it lacked a definitive basis to differentiate the costs of the training facility component from the NDSC project, so it removed the costs of the entire NDSC project from rate base in its 2013-2015 PBR capital tracker compliance application.²⁶⁶ In this application, ATCO Electric noted that the scope, nature and drivers for the NDSC project have not changed from those presented in Proceeding 3218 for 2013, 2014 and 2015. ATCO Electric provided information on costs of prior year actuals and future year forecasts and reapplied for capital tracker treatment of the capital expenditures, as all of the capital additions have been made. ATCO Electric submitted that this is in keeping with the directions in paragraph 48 of Decision 2013-435, where the Commission stated that a company may apply for capital tracker treatment of capital expenditures after the capital additions are made.²⁶⁷

230. In Appendix C of its business case, ATCO Electric provided a breakdown of its actual costs in 2014 for the project. The 2014 forecast capital additions for this project were \$3.2 million, while the actual 2014 capital additions were \$3.0 million, resulting in a \$0.2 million negative variance. ATCO Electric submitted that its forecast estimate had an expected accuracy of +/- 10 per cent, and that its variance in costs is within that estimation accuracy and Rule 005 variance reporting thresholds.²⁶⁸

231. In ATCO Electric's view, the training facility component of the NDSC project is prudent and reasonable for the following reasons.

232. ATCO Electric submitted that it has specific certifications from the Alberta Apprenticeship and Industry Training (AAIT) department that do not allow for training of utility workers beyond ATCO Electric employees. Similarly, other utilities that are subject to the same AAIT requirements would be unable to train ATCO Electric employees. ATCO Electric provided the certification as Appendix D to its business case.²⁶⁹ ATCO Electric also submitted that under the Alberta *Occupational Health and Safety Regulation*, AR 62/2003, Section 15, an employer is required to train its workers in the safe operation of the equipment, which includes training on utility specific facilities, equipment and protocols.²⁷⁰

233. ATCO Electric confirmed that Northern Alberta Institute of Technology (NAIT), Southern Alberta Institute of Technology and other post-secondary institutions do not have the facilities, equipment or trainers to deliver adequate technical training for line and service personnel of ATCO Electric. ATCO Electric explained that NAIT is the only non-utility power line technician (PLT) apprenticeship training organization in Alberta and is limited as to what it provides for power line technician training. For example, NAIT does not have labs with overhead and underground lines which include real electric distribution equipment. ATCO Electric submitted that it requires live line training for employees to ensure they have practical

²⁶⁶ Proceeding 20369.

²⁶⁷ Exhibit 20555-X0004, PDF page 41.

²⁶⁸ Exhibit 20555-X0004, PDF page 42.

²⁶⁹ Exhibit 20555-X0004, PDF page 44.

²⁷⁰ Exhibit 20555-X0004, PDF page 34.

experience. ATCO Electric noted that the Alberta PLT apprenticeship curriculum offered by NAIT, which is dictated by the Alberta government, does not require training such as live line techniques. Additionally, even if such training were permitted, ATCO Electric submitted that NAIT lacks the trainers, training materials, facilities and equipment to deliver post-apprenticeship training such as live line training.²⁷¹

234. Following its discussions with three utilities, EPCOR, ENMAX Power Corporation and FortisAlberta Inc. (FortisAlberta), ATCO Electric confirmed that a combined training facility is not a feasible option as it would involve investment and expansion of existing facilities and poses many difficulties including increased travel costs, additional trainers, and purchase of multiple equipment types. Additionally, ATCO Electric explained that the Canadian Electrical Code, Part 3, for utilities applies to higher level engineering design criteria. The design and construction of each utility's assets can and usually does differ amongst utilities. A combined training facility would be feasible if there were uniform sets of construction standards, equipment and safety protocols. However, there is no such standard and under the *Safety Codes Act*,²⁷² each utility is responsible for and accountable to their design, construction, equipment use and their safety protocols.²⁷³

235. To explore how the equipment used by each utility differs, Commission counsel engaged in the following exchange with Mr. Howell during the hearing:

Q. Could you give me an example of how have utilities equipment might differ?

A. MR. HOWELL: Yes. So as we look at our -- at the standards of equipment that we buy -- and we're different than an urban utility like EPCOR and ENMAX, and we're also different in some cases with what we buy and purchase with respect to equipment than Fortis.

So we might have gas insulated equipment, or we might have complicated electronic controllers for our regulators and reclosers and things like that, that are just different than what the urban utilities and Fortis would use.

We also referred in that same paragraph to additional trainers. And it goes to our work standards. So we, as a company, are obligated to give our people the training that is required to keep them safe when they're working on our stuff.

And that means when I say "stuff," I mean not only equipment but structures and vehicles and all that sort of thing. So when we purchase a new tool and introduce it to our company, we want to make sure that our workers are qualified to use it safely so it does its intended purpose.

It may be something that's trying to identify which cable to cut in a bank of three, and we want to make sure our guys can operate it right. We want them to be able to drive our trucks, and we want them to be able to operate the material and transformers and switchgear that we buy.²⁷⁴

236. ATCO Electric also added that it uses external training programs to meet its needs where customization is not required. The nature of these types of training was expanded upon during the hearing.

²⁷¹ Exhibit 20555-X0004, PDF pages 33-34.

²⁷² *Safety Codes Act*, RSA 2000, c. S-1, Section 5.

²⁷³ Exhibit 20555-X0004, PDF pages 34-35.

²⁷⁴ Transcript, Volume 2, page 342, line 8 to page 344, line 11.

Q. Mr. Marriott... And does ATCO Electric use NAIT for some apprenticeship training as well?

A. MR. HOWELL: Not for power line technicians, but we would for mechanics, electrical technologists, and meter techs, and some of those other job classes, but not for power line technicians. We have quite a number of them, a critical mass, where we can effectively run that program on our own.²⁷⁵

237. None of the interveners raised any objections or concerns regarding this project.

Commission findings

238. In Decision 3218-D01-2015, the Commission found that the various functional elements of the NDSC project were required to maintain service reliability and safety at adequate levels in 2013. The Commission denied capital tracker treatment for the training facility component of the NDSC project on the grounds that ATCO Electric did not consider potentially reasonable alternatives and therefore, there was insufficient evidence for the Commission to determine whether it satisfied the requirements of Criterion 1. However, the Commission found that the project, other than the training facility component of the project, satisfied the project assessment requirement of Criterion 1 in 2013, 2014 and 2015.²⁷⁶

239. ATCO Electric has reapplied for capital tracker treatment for the NDSC project after the capital additions related to this project have been made. ATCO Electric submitted that this is in keeping with the directions at paragraph 48 of Decision 2013-435, where the Commission stated that a company may apply for capital tracker treatment of capital expenditures after the capital additions are made. Upon reviewing the application, the Commission finds that ATCO Electric has addressed the deficiencies identified in Decision 3218-D01-2015 regarding the training component of the NDSC project, including the consideration of potentially reasonable alternatives such as forming a joint venture with NAIT, or cooperating with other utilities to build a shared facility in order to provide training to its technicians at the lowest cost possible.

240. Given the evidence on the record, the Commission is satisfied that it would not be feasible for ATCO Electric to form a joint venture with a post-secondary institution or any other utility at this time. An essential function of the training facility is to train PLTs. Post-secondary institutions like NAIT neither have labs with overhead and underground lines which include real electric distribution equipment, nor do they have the trainers, training materials, facilities or equipment to deliver post-apprenticeship training.²⁷⁷ ATCO Electric's use of external training programs when they are able to meet its needs, is evident by its use of NAIT to train its metering graduates.²⁷⁸ The Commission has also come to the understanding that a combined training facility with other utilities would not be feasible because of the differences in the design and construction standards and procedures and the equipment used.²⁷⁹ As explained by Mr. Howell to Commission counsel,²⁸⁰ ATCO Electric trains its employees on specific equipment using specific work methods to ensure the safety of its employees, and, additionally, specialization is required as the equipment used varies amongst utilities because of differences in their respective service

²⁷⁵ Transcript, Volume 2, page 240, lines 10-17.

²⁷⁶ Decision 3218-D01-2015, paragraphs 183, 185 and 187-189.

²⁷⁷ Exhibit 20555-X0004, PDF page 34.

²⁷⁸ Exhibit 20555-X0004, PDF page 35.

²⁷⁹ Exhibit 20555-X0004, PDF page 35.

²⁸⁰ Transcript, Volume 2, page 342, line 8 to page 344, line 23.

areas (urban vs. rural). The Commission also takes note of the specific certifications from AAIT that do not allow for training of utility workers other than ATCO Electric employees.²⁸¹

241. Accordingly, the Commission finds that ATCO Electric has reasonably demonstrated that owning and operating its own training facility is the only viable option in the current circumstances. In Decision 3218-D01-2015, the Commission found that the NDSC project, with the exception of the training facility component of the NDSC project, satisfied the project assessment requirement of Criterion 1 in 2013, 2014 and 2015. Since, there is no evidence on the record of this proceeding to indicate that the other component of the NDSC project previously approved in Decision 3218-D01-2015 was not required in 2014, there is no need to demonstrate it was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. Consequently, the Commission finds that the entire NDSC project satisfies Criterion 1.

242. In Decision 3218-D01-2015, the Commission found that, “ While the Commission is unable to make a finding with respect to capital tracker treatment for the actual and forecast capital costs associated with the training facility component of the project at this time, the Commission notes the statement made at paragraph 48 of Decision 2013-435, that a company may apply for capital tracker treatment of capital expenditures after the capital additions are made.”²⁸² Accordingly ATCO Electric is permitted to include in its K factor the revenue requirement associated with the capital additions in 2013, that is not funded by the I-X mechanism. ATCO Electric is directed to include this amount in its compliance filing.

243. The Commission has reviewed the costs of the 2014 actual capital additions for the NDSC project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

6.2.3.4 Valleyview Service Building

244. In Proceeding 3218, ATCO Electric proposed the purchase of 12.2 acres of land and renovation of an existing 14,020 sq. ft. industrial building in Valleyview, Alberta at a capital cost of \$6.8 million. ATCO Electric submitted that the new facility was required to accommodate existing personnel and staff increases and to improve emergency and outage response time. The project included planning, design and renovation of the Blackwatch building and completion of site and yard development.²⁸³ ATCO Electric provided an update to its business case, originally filed in Proceeding 3218, in Appendix B Part 2, Project Update B.4.²⁸⁴

245. The Commission made the following findings with regards to this project in Decision 3218-D01-2015:

203. With respect to ATCO Electric’s request for capital tracker treatment for 2013 based on 2013 actual capital additions, the Commission has reviewed the scope, level, and timing of the Valleyview Service Building project carried out in 2013, and the 2013 actual capital additions of \$6.3 million. The Commission has reviewed the scope, level and timing of the project in 2013, including the alternatives considered, as well as the

²⁸¹ Exhibit 20555-X0004, PDF page 44.

²⁸² Decision 3218-D01-2015, paragraph 188.

²⁸³ Exhibit 20555-X0004, PDF page 65.

²⁸⁴ Exhibit 20555-X0004, PDF Page 65.

costs of the actual capital additions for this proposed capital tracker in light of the evidence on this project and the procurement, construction and project cost management practices outlined in ATCO Electric's Capital Project Delivery model. Subject to the comments below with respect to the unutilized portion of the purchased property, the Commission finds, the scope, level, timing and actual costs for this project in 2013 to be prudent. Accordingly, the Commission finds that the Valleyview Service Building project satisfies the project assessment requirement of Criterion 1 in 2013.

...

206. Given the above, the Commission finds that the evidence provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Valleyview service building project are reasonable as proposed for 2014. Accordingly, the Commission finds, subject to the comments below with respect to the unutilized portion of the purchased property, that this project satisfies the project assessment requirement of Criterion 1 in 2014.

...

210. In light of the guidance provided by the Salt Caverns II decision, the findings of the Commission in Decision 2013-417²⁸⁵ and the evidence of ATCO Electric that it is using six of the 12.2 acres of the land purchased in Valleyview for utility operational purposes and that the remaining land does not, and will not, have a utility operational purpose until at least the "midterm," the Commission directs the value of the 6.2 acres of land not being used for utility operational purposes be excluded from the calculation of the Valleyview service building capital tracker costs and excluded from the rate base of ATCO Electric. Should the property be subdivided by ATCO Electric, the costs of such subdivision will be for the account of ATCO Electric's shareholder. If the unutilized land subsequently develops an operational purpose for providing utility service, ATCO Electric may apply to have the property added to rate base at that time.

246. ATCO Electric confirmed that the scope, nature and driver for the Valleyview Service Building project have not changed since its approval in Decision 3218-D01-2015. In keeping with the Commission's directions, ATCO Electric also removed the costs associated with the 6.2 acres of land from the capital tracker costs of this project.²⁸⁶

247. In Appendix B of its business case, ATCO Electric provided a breakdown of its actual capital additions for 2014. There was no variance between the actual and forecast capital additions, which were forecast at \$0.5 million.²⁸⁷

248. No interveners raised concerns about this project.

Commission findings

249. In Decision 3218-D01-2015, the Commission approved the need for the Valleyview Service Building project for purposes of capital tracker treatment in 2014.²⁸⁸ Further, the Commission determined that the proposed scope, level, timing and forecast costs for this project were reasonable. Therefore, the Commission has previously determined that this project satisfied the project assessment requirement of Criterion 1. In addition, in Decision 3218-D01-2015 and

²⁸⁵ Decision 2013-417: Utility Asset Disposition, Proceeding 20, Application 1566373-1, November 26, 2013.

²⁸⁶ Exhibit 20555-X0004, PDF page 65.

²⁸⁷ Exhibit 20555-X0004, PDF pages 71.

²⁸⁸ Decision 3218-D01-2015, paragraph 203

the related compliance filing Decision 20369-D01-2015 (Errata) the Commission approved the actual scope, level, timing and costs of this project included in the 2013 capital tracker true-up application, as prudent.²⁸⁹

250. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that this project was not required in 2014.

251. With respect to the scope, level and timing of this project carried out in 2014, the Commission has reviewed ATCO Electric's 2014 actual capital additions of \$0.5 million associated with this project and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for this project and approved in Decision 3218-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this project in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

6.2.3.5 Fort McMurray North Service Building

252. The purpose of this project is to construct a new 21,371 sq. ft. service building on the north side of Fort McMurray (i.e., north of the Athabasca River) at an estimated capital cost of \$21.1 million. ATCO Electric is applying for capital tracker treatment for the Fort McMurray North Service Building project (new facility) in each of 2016 and 2017. ATCO Electric forecast capital additions of \$20.5 million in 2016 and \$0.61 million in 2017.²⁹⁰ ATCO Electric provided a business case in Appendix B Part 2, Business Case B.5.²⁹¹

253. ATCO Electric submitted that rapid growth in the infrastructure installed in the Fort McMurray service area in recent years has greatly increased the work force needed to operate and maintain it, with staff growing from 39 in 2007 to 103 in 2014.²⁹² The resulting overcrowding at ATCO Electric's existing, owned south service centre (which is south of the Athabasca River) at 190 Mackay Crescent (south service centre) led ATCO Electric to obtain a lease for another property at an old airport facility in Fort McMurray (the airport facility). ATCO Electric's lease of the airport facility expires in September, 2019.²⁹³

254. ATCO Electric indicated that in order to prudently manage its long-term spatial needs in Fort McMurray, it will continue its use of the existing south service centre and plans to build the new facility in the north of Fort McMurray to replace the airport facility. ATCO Electric expressed the view that moving into its own facilities will provide more security because there is

²⁸⁹ Decision 3218-D01-2015, paragraph 204 and Decision 20369-D01-2015 (Errata), paragraph 18.

²⁹⁰ Exhibit 20555-X0004, PDF page 84.

²⁹¹ Exhibit 20555-X0004.

²⁹² Exhibit 20555-X0071, Undertaking 17.

²⁹³ Transcript, Volume 2, page 291, lines 19-25.

a risk that landlords may prematurely terminate a lease with six months' notice or less, as had been its experience with a previously leased space at 230 Mackay Crescent in Fort McMurray.²⁹⁴

255. ATCO Electric explained that the new facility will be in service in December, 2016, which is two years prior to the expiry of the lease at the airport facility. During the period between completion of the new facility and the expiry of the lease at the airport facility, ATCO Electric plans to temporarily relocate some of its employees from the south service centre to the new facility to facilitate renovations at its south service centre. Once the deficiencies are addressed at the south service centre, ATCO Electric intends to relocate some of its staff back to the south service centre site. By 2019, ATCO Electric projected to have all its employees housed at its two owned facilities, with 73 employees at the south service centre, and 51 employees at the new facility.²⁹⁵

256. Regarding the need for a new facility, ATCO Electric submitted that the airport facility is not an ideal space as it is a shared with other third-party businesses and has restrictions that do not satisfy ATCO Electric's longer term needs for equipment, material storage and manpower. ATCO Electric also cited locational constraints as the airport facility's proximity to the airport limits the site's flexibility; for instance, ATCO Electric cannot undertake certain necessary renovations because of restrictions on the site development at the airport lot.²⁹⁶

257. ATCO Electric added that having a service centre in the north will enable it to improve response times for emergencies and customer service requests on the north side of the river by eliminating traffic delays caused by crossing the Athabasca River. ATCO Electric submitted that this will improve reliability and customer satisfaction in the north of Fort McMurray.²⁹⁷

258. In response to a Commission request,²⁹⁸ ATCO Electric provided information on customer growth experienced in the past decade along with projections of future growth in Fort McMurray. During the hearing, Commission counsel questioned ATCO Electric regarding how the need for a new facility may be impacted by the projected economic slowdown in Fort McMurray. On behalf of ATCO Electric, Mr. Howell replied:

MR. HOWELL: Well, if you look at the growth the past decade, especially in the housing starts, but in the capital expenditures as well, we've been building a considerable amount of infrastructure that now needs to be operated; and what we're finding is -- and we talked earlier about the addition of -- or the ratio of company crews to contractor crews and the fact that the people that we're housing in these buildings are crews that are sized to do the -- sort of the base level of sustainment capital and really aren't -- we don't have -- we're not trying to house enough people to do the peak workloads. We're trying to house enough people to do the base workloads.

And at the same time, we've built a lot of facilities over the last while; put in a lot of subdivisions that are filled with houses. We've got a lot of commercial, industrial customers and industrial parks and all that sort of thing that now have to be operated. And that's what we're trying to do, is to maintain the people that we need to continue to keep the lights on in those -- in that community, as well as do the base level of work. And

²⁹⁴ Exhibit 20555-X0023, AE-AUC-2015JUL20-015.

²⁹⁵ Exhibit 20555-X0021, AE-UCA-2015JUL20-025(e).

²⁹⁶ Exhibit 20555-X0004, page 10 and Transcript, Volume 4, page 596, lines 1-3.

²⁹⁷ Exhibit 20555-X0004, PDF page 85.

²⁹⁸ Exhibit 20555-X0023, AE-AUC-2015JUL20-013.

we just are trying to get a long-term solution where we're not reliant upon leased space that's here today and gone tomorrow.²⁹⁹

259. The UCA submitted that this project does not satisfy the test for capital tracker treatment because it does not satisfy Criterion 1. Specifically, the UCA submitted that ATCO Electric did not demonstrate that the need, scope and timing of the project is reasonable. The UCA argued that the testimony of Mr. Howell on behalf of ATCO Electric indicated that ATCO Electric is able to maintain service quality and safety with its existing south service centre and airport facility, and that the proposed new building only serves to enhance quality, which is not a relevant consideration given Criterion 1. In support of its argument, the UCA provided the following exchange between Mr. Marriott and Mr. Howell:

MR. MARRIOTT: So the construction of the north service centre enhances service levels; is that right?

MR. HOWELL: Yes. That's correct.

...

MR. MARRIOTT: I think that's kind of what I was getting at, that, you know, having run out of space, you needed to do something or else service quality would have deteriorated; isn't that fair?

MR. HOWELL: Correct. I can accept that.

MR. MARRIOTT: And since then, though, through the use of the lease space since 2014, ATCO Electric has been able to maintain service at adequate levels. Is that fair?

MR. HOWELL: We have been. One of the key considerations that we always have is with respect to the -- our ability to stay in the lease space. As I've pointed out, we've had a little bit of trouble finding and maintaining leased spaces due to the Fort McMurray market. And we have put on -- I want to find a reference. Yeah, so I think it was in AUC-15, information response to AUC-15 where we spoke about the difference between leasing and owning buildings. And in AUC-13, I think we've pointed out some of the difficulties we'd have with the leased space and having to potentially renew the lease a number of times just to -- or if we can in fact find lease spaces.

So I think with that caveat, I think today our services, we're doing our best to keep it at an acceptable level despite the restrictions.³⁰⁰ [emphasis added by the UCA]

260. The UCA also argued that ATCO Electric has not provided any evidence that shows the risk of a potential sudden termination at the airport facility is real and substantial. It noted that the termination of the 230 Mackay Crescent lease occurred in May 2014, at a time when the Alberta economy, and the Fort McMurray market in particular, was on an upswing. The UCA submitted, "all other things being equal, the current economic conditions make it less likely that AE's current lease will be terminated prematurely."³⁰¹ The UCA further submitted in its argument:

... that it would be premature to make any assumptions as to the likelihood of renewal of that lease, which is not due to expire until 2019. Economic and other relevant factors may change drastically in the intervening period...³⁰²

²⁹⁹ Transcript, Volume 2, page 360, line 17 to page 361, line 15.

³⁰⁰ Transcript, Volume 2, page 250, line 5 to page 251, line 21, as cited in the UCA's argument, Exhibit 20555-X0074 at paragraph 33.

³⁰¹ Exhibit 20555-X0074, UCA argument, paragraph 36.

³⁰² Exhibit 20555-X0074, UCA argument, paragraph 37.

261. With regard to ATCO Electric's evidence on the need for the project, the UCA submitted:

... the UCA is of the view that AE has failed to establish the need for the proposed Ft. McMurray service building and, specifically, that the project is required now or during the time frame under consideration in this application to maintain service quality and safety.³⁰³ (emphasis added by the UCA)

262. The UCA also argued that ATCO Electric failed to prove the prudence of the scope of the project as it only explored lease options related to existing facilities and did not specifically consider a build-to-lease option. Mr. Bell, on behalf of the UCA, explained the features of a build-to-lease option and how it could be a feasible alternative for ATCO Electric:

And while there may not have been adequate space, according to ATCO Electric, at the time that they did the analysis, it didn't have any analysis that I recall of talking to a developer who would be willing to build a facility to suit ATCO Electric's needs, what the cost of that facility would be, and how that would compare to a build-it yourself and own it and operate it alternative.

And that's what I'm talking about, when I talk about "build to lease," it would be having a developer build a facility to your specifications, own it, and lease it to you for a long term.

And I haven't seen any analysis or detailed discussions of that on the record. I saw – and Mr. Howell pointed to general concerns with leasing, but not to the specific consideration of having a developer build something specifically suited to ATCO Electric's needs for the term of a lease, 10, 20, 30 years.³⁰⁴

263. Lastly, with regard to the timing of the project, the UCA raised issue with ATCO Electric's proposal to build the new facility two years prior to the expiration of the lease at the airport facility in order to accommodate the renovations at the south service centre. The UCA submitted that neither is there evidence on the record of this proceeding that a renovation, expansion or other work will be required at the south service centre at some future date in order to prevent deterioration in service quality or safety, nor is there evidence as to the nature, scope or timing of any such future project. The UCA argued that it is unfair for customers to bear the costs of both facilities for the purpose of accommodating a wholly separate project of unknown scope and timing, which may or may not satisfy the criteria for capital tracker treatment. Accordingly, the UCA submitted that ATCO Electric failed to establish that the timing of the project is prudent.³⁰⁵

264. In relation to traffic delays between the north and south sides of the river, the CCA referred to a graph provided by ATCO Electric which illustrates the average duration of unplanned interruptions over 2013 and 2014 for the north and south portions of the Fort McMurray service area, as compared with the Lloydminster and Grande Prairie service areas.³⁰⁶ Based upon the information provided by ATCO Electric, the CCA observed that there is not a substantial difference in the duration of average interruption between Fort McMurray north and south, or when compared to Lloydminster and Grande Prairie. The CCA also noted that outage

³⁰³ Exhibit 20555-X0074, UCA argument, paragraph 38.

³⁰⁴ Transcript, Volume 4, page 697, line 13 to page 698, line 9.

³⁰⁵ Exhibit 20555-X0074, UCA argument, paragraphs 44-46.

³⁰⁶ Exhibit 20555-X0068, Undertaking 13.

duration decreased in 2014 in the north of Fort McMurray. The CCA concluded that it does not appear that moving a facility to the north would have much of an impact on response times and outages. For these reasons, the CCA submitted that the new facility is not warranted as a capital tracker at this time.³⁰⁷

265. In reply argument, ATCO Electric addressed both the CCA's and UCA's arguments on the need, scope and timing of the project. ATCO Electric provided an excerpt from Mr. Howell's testimony summarizing the need for the project:

MR. HOWELL: So the business case I thought was fairly thorough in terms of outlining the crowding and the conditions that we have to work with. It talked about, again, the things that I mentioned about the shortcomings of the facility that we have over at the airport and the segregation of the work groups that support those crews. So we have all that evidence on the record, and we've talked at great length about how we have the construction crews that can't effectively work, and, of course, they're dealing with customer extensions and building power lines and customer in service dates. And we've talked about -- just now about the -- and in the business case, I guess -- about the service teams that are not really having adequate space back for their storage of their tools and equipment and for their minimal office requirements back -- back in the warehouse building there where they're awkwardly located out in the mezzanine floor above the warehouse shop sort of thing and filling up coffee room space and all that sort of thing. So we've put a fair bit of information on the crowding and on the growth that happened up until 2010 and even up until this year. And we have talked about some potential advantages in the long term of being on the north side. So I think we've got that -- that evidence on the record.

I just wrote down a couple of references here. We also have put information on the record -- and we will more on the record -- with respect to outages north and south.

We talked about the split of north and south customer service, but really it's the aggregate needs of our operation in Fort McMurray overall that dictate our need for the new building. The fact that we located one in the north and one in the south is opportune, but it was driven by past growth and by the conditions that we've described in our business case.

... And I guess we're trying to hang on until 2019 and get some more facilities build to make the situation a little better; but, in the meantime -- I guess I'm not to the point where I'm going to -- we're certainly challenged in providing safe and reliable service, let's put it that way. I sure hope that we're not compromising safety, but there's certainly risk there.³⁰⁸

266. ATCO Electric argued that it never suggested that the need for the new facility is premised on the termination of the airport lease before 2019. ATCO Electric asserted that there are significant shortcomings with respect to the airport facility, which are summarized in Mr. Howell's response below:

We went ahead and started leasing a spot at the airport. It was all that was available at the time, and that -- when our lease at MacKay was terminated. And we really had no choice as to where to go.

We settled for a less than ideal site. We moved to the airport. It's restrictive and only partially meets our line crew's needs. They're partly in trailers. There's another tenant in

³⁰⁷ Exhibit 20555-X0076, CCA argument, paragraphs 129-132.

³⁰⁸ Transcript, Volume 4, pages 598-599 and pages 604-605.

the office building that we share -- we have to share with on site. And the airport was always only intended to be a temporary facility. We can't do the needed renovations because of the particular restrictions on the site development at the airport lot.³⁰⁹

267. ATCO Electric submitted that the UCA's argument with regard to prudence of the scope of the project is invalid, as ATCO Electric has incorrectly equated the assessment of alternatives with the scope of the project. ATCO Electric advised that it does not consider a build-to-lease to be an economically viable option for several reasons: first, regular escalation of the rent to reflect market rates upon renewals in an area such as Fort McMurray contrasts with an owned option where only historic land costs incurred and depreciated building costs are factored into rates; second, the utility's cost of capital is likely to be less than a developer's, rendering Mr. Bell's option intuitively unattractive; and third, there has been no evidence of this option being available in the area; and no evidence it would be less costly.³¹⁰

268. In order to address the UCA's argument with regard to the prudence of the timing of the project, ATCO Electric underscored the aggregate needs of its operations in Fort McMurray as the main driver for the need and timing of the new building, which requires the continued use of its south service centre. ATCO Electric asserted that it must relocate a portion of the distribution operations staff to the new facility in 2016 in order to relieve the overcrowding at the south service centre and permit the renovations in the warehouse. Moreover, ATCO Electric confirmed that it had provided various discussions on the deficiencies of the warehouse building in the south service centre throughout the proceeding.³¹¹

Commission findings

269. The Commission accepts ATCO Electric's evidence that Fort McMurray has experienced a high level of growth in housing and capital activity over the past decade, as evidenced in AE-AUC-2015JUL20-013, and that a corresponding increase in ATCO Electric's staff has resulted in overcrowding of the south centre, as evidenced in Undertaking 17, which shows that ATCO Electric's employees grew from 39 in 2007 to 103 in 2014, and in Mr. Howell's exchange with Commission counsel:

MR. HOWELL: Well, if you look at the growth the past decade, especially in the housing starts, but in the capital expenditures as well, we've been building a considerable amount of infrastructure that now needs to be operated; and what we're finding is -- and we talked earlier about the addition of -- or the ratio of company crews to contractor crews and the fact that the people that we're housing in these buildings are crews that are sized to do the -- sort of the base level of sustainment capital and really aren't -- we don't have -- we're not trying to house enough people to do the peak workloads. We're trying to house enough people to do the base workloads.³¹²

270. Additionally, the Commission is persuaded by the reasons provided by ATCO Electric as to why the airport facility is not suitable as a long-term solution to ATCO Electric's spatial needs, which include restrictions on its usage due to its proximity to the airport and due to it being a shared facility with other tenants.

³⁰⁹ Transcript, Volume 4, page 595, line 15 to page 596, line 8.

³¹⁰ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 23.

³¹¹ Exhibit 20555-X0080, ATCO Electric reply argument, paragraphs 24- 26.

³¹² Transcript, Volume 2, page 360, line 17.

271. While the Commission understands that construction of the new facility may yield advantages by enabling ATCO Electric to move into its own facility and potentially improve response times for emergencies and customer service requests in the north of Fort McMurray, the Commission finds that these benefits did not drive the need of the project. However, the Commission accepts ATCO Electric's argument that the need for the new facility was not premised on the termination of the airport lease before 2019³¹³ or to locate the facility to the north of Fort McMurray.³¹⁴

272. Consequently, the Commission finds that the need for the new facility is dictated by high levels of past growth experienced in Fort McMurray, overcrowding in its south service centre and the unsuitability of the airport facility as a long-term option.³¹⁵

273. The Commission does not accept the UCA's argument that the scope of the project should be deemed imprudent because ATCO Electric did not consider a build-to lease option. The Commission finds that the UCA has not provided sufficient evidence to demonstrate that this option could be more cost effective. Nor has the UCA presented evidence of real estate developers who provide such services in Fort McMurray. Upon reviewing Appendix C, which specifies the spatial requirements for the new facility based on ATCO Electric's existing and forecast staffing levels, the Commission is satisfied that the scope of the project is reasonable.

274. However, the Commission is not satisfied that the timing of the construction of the new facility is reasonable. The new facility is being constructed more than two years prior to the expiration of the lease at the airport facility in order to accommodate renovations at the south service centre. ATCO Electric indicated that "the warehouse building located on the same site as the district office building requires extensive repairs and improvements",³¹⁶ however, ATCO Electric failed to provide sufficient information explaining the full nature and scope of the renovations to be undertaken at the warehouse and yard space in the south service facility. As admitted by ATCO Electric, it is not aware of the full scope and nature of the renovations that it plans to undertake, and only intends to submit its proposal for renovations in a future proceeding:

... Based on a preliminary needs assessment and a Building Condition Report carried out in 2010, significant capital investment would be required to address interior and exterior deficiencies and to accommodate growth.

With the North building proceeding, the size of the property at the south side appears to be adequate, however given the condition of the warehouse building and the current layout of the yard and buildings, consideration of all options at the South Facility are being undertaken to consider how best to meet business needs in the future. A design assessment and updated Building Condition Report is planned to be conducted by 2017. Demolition of the warehouse space or other options will depend upon the reports mentioned above.³¹⁷

... The sizing and layout of both the warehouse and the office building will be determined later in light of the most recent forecasts then available and will be brought forward for the Commission's review in a future proceeding after 2017.³¹⁸

³¹³ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 13.

³¹⁴ Transcript, Volume 4, pages 598-599 and 604-605.

³¹⁵ Transcript, Volume 4, pages 598-599 and 604-605.

³¹⁶ Exhibit 20555-X0023, AE-AUC-2015JUL20-014(a).

³¹⁷ Exhibit 20555-X0023, AE-AUC-2015JUL20-014(b).

275. Given the lack of evidence, the Commission finds the UCA's concern, as expressed in the quote below, to be valid:

AE intends to create an overlap of significantly longer duration for the sole purpose of accommodating a wholly separate project of unknown scope and timing, which project may or may not meet the criteria for Capital Tracker. The UCA submits that there is a very real risk that, in AE's scenario, customers will bear the increased costs associated with both the new north service centre and the leased airport facility for a longer period than necessary to maintain service quality and safety. If AE was of the view that the timing of the construction of the proposed north service centre was dependent on its plans for renovation of the south service centre, it would have been open to AE to present the two projects as part of one larger capital project, so as to enable the Commission to consider the application of Criterion 1 against a full evidentiary record.³¹⁹

276. In the absence of a complete building assessment report, the Commission cannot adequately determine that renovations are required to begin immediately or that the renovations cannot be delayed until closer to the expiry of the lease for the airport facility.

277. The Commission also notes that ATCO Electric did not provide any evidence on the record to demonstrate that it had considered alternatives such as relocating its staff elsewhere temporarily while the renovations take place, instead of building the north facility two years early. ATCO Electric explained that there are 66 employees in the south service centre, of which 19 are in the office and 47 are in the warehouse. ATCO Electric intended to relocate 39 staff (19 from the office and 20 from the warehouse) to the new facility once it is in service. During the hearing, ATCO Electric discussed the nature of the work performed by the staff housed in the warehouse:

Q. ... So I was a bit surprised to learn how many people you have housed in the warehouse, and I'm wondering, are these office staff that actually have offices in the warehouse, or are these field employees that come and go?

A. MR. HOWELL: These are -- so what we have in the warehouse are people that -- they do some of each kind of work. So they would be -- some of them are the power line technicians in the service group that are out doing work, but some of them, at other times in the day, they do have some office work to do, so they require a desk. It's not a lot of office space, but they do require desk space.³²⁰

278. In the Commission's view, deliberation of alternatives such as temporary relocation of staff may have been an important consideration, particularly in light of the fact that the staff at the warehouse does not require a significant amount of desk space.

279. In light of the above considerations, the Commission finds that ATCO Electric has not adequately demonstrated the reasonableness of the timing for the new facility. Accordingly, the Commission is not satisfied that this project meets the project assessment requirement of Criterion 1. Therefore, the capital costs of the Fort McMurray north service building are denied capital tracker treatment as proposed for 2016 and 2017 at this time.

³¹⁸ Exhibit 20555-X0075, ATCO Electric argument, paragraph 67.

³¹⁹ Exhibit 20555-X0074, UCA argument, paragraph 45.

³²⁰ Transcript, Volume 4, page 592, lines 9-21.

6.2.3.6 High Level Service Building

280. This project consists of constructing a new 35,893 sq. ft. service building (new building) in High Level, Alberta, at an estimated total cost of \$24.3 million.³²¹ The proportion of costs for the distribution function is estimated at \$19.4 million, based on the distribution function's occupancy requirements forecast to be 80 per cent of the new building. ATCO Electric transmission is forecast to occupy the remaining 20 per cent.³²² ATCO Electric provided a business case in Appendix B Part 2, Business Case B.6.³²³

281. ATCO Electric submitted that the report prepared by Manasc Isaac Architects and Engineers, attached as Appendix C of the business case, demonstrates that the existing building at High Level is at the end of its useful life, and establishes the need for the project. The report identified several major building code violations, confirmed that the building's condition and configuration does not satisfy the current Alberta Building Code's design requirements, and concluded "As a result, long term continued occupancy of the building is not possible. This is not a condemnation of the building but a serious recommendation to provide a new location for the staff as soon as is feasible and no longer than 2 years."³²⁴ ATCO Electric further noted that the existing office building and garage bays are not built for industrial use.

282. ATCO Electric argued that its existing building is not adequate to accommodate existing staff and other resources that are required to meet the current service demands within the area. In Appendix D of its business case, ATCO Electric provided information showing the growth of its new assets and capital replacement programs, and capital activities in High Level, which has driven the growth in its employees.³²⁵ ATCO Electric submitted that the High Level Service Building was built in 1969 and designed for a staff complement of eight employees. ATCO Electric projected that the staff complement, including near-term growth, to be 32 employees.³²⁶

283. ATCO Electric forecasted modest growth in High Level in the near future, and explained that this growth would result in more staff and resources than could be accommodated at ATCO Electric's current building. In ATCO Electric's view, its current building will have a spatial shortfall of 24,313 sq. ft. by 2019 as shown in the table below:

Table 24. Existing and required spatial needs for High Level³²⁷

Space	Existing 2015	Required 2019	Space shortfall
Owned office (sq. ft.)	5,385	11,676	6,291
Owned garage bays (sq. ft.)	6,195	24,217	18,022
Total building area (sq. ft.)	11,580	35,893	24,313

284. In explaining the enhanced scope of the new building, ATCO Electric submitted in an IR response that:

³²¹ Exhibit 20555-X0004, PDF page 109.

³²² Exhibit 20555-X0023, AE-AUC-2015JUL20-020.

³²³ Exhibit 20555-X0004, PDF page 108.

³²⁴ Exhibit 20555-X0004, PDF page 207.

³²⁵ Exhibit 20555-X0004, PDF page 179-180

³²⁶ Exhibit 20555-X0004, PDF page 133.

³²⁷ Exhibit 20555-X0004, PDF page 120.

The majority of the increase in space (18,022 square feet) is related to the additional garage bays required to accommodate large fleet vehicles associated with construction and maintenance activity. As well, additional bay space is required for the new mechanics shop and related equipment.³²⁸

285. In Appendix B of its business case, ATCO Electric provided a breakdown of its spatial requirements for its new building. Specifically, the distribution function will have the following garage bays in the new building: a service truck bay of 2,000 sq. ft., a wash bay of 2,400 sq. ft., two mechanics bays with a combined area of 4800 sq. ft. and a project and construction bay of 5,000 sq. ft. The transmission function will have two additional services bays, each comprising an area of 2,000 sq. ft. ATCO Electric submitted that its existing building has two bays which are used by the distribution function, and a third bay, which is used by the transmission function, and no wash bay.³²⁹

286. During the hearing, Commission counsel inquired about the need for the additional garage bays, to which Mr. Howell replied:

MR. HOWELL: And my answer was that, since we put that building up, we've expanded by a considerable number of employees and crews, all of who have equipment that needs to be put in the bays to work on and to keep ready to respond to trouble. So we've grown our crews. We haven't grown our space for 15 years, and we're crowded.³³⁰

I think we've -- we've provided the -- Manasc Isaac report on the unsafe conditions and the safety protocols that we have to put in place to manage around some of those things, meaning that we can't -- often when we are in need of our equipment and we're shooting trouble and power's out in the middle of storms, those bays aren't even available to us because of the snow and wind loading. We have to actually restrict occupancy of those bays at those times.³³¹

287. In response to an inquiry during the hearing regarding the need for the wash bay, Mr. Howell provided the following response:

No, we do not. So the wash bay when we -- it's certainly not the driver for the new facility,... It really goes to our ability to operate with some of the -- they get offroad, and they get all stuck up with mud, and it takes a fair bit of effort to loosen up. So having a wash bay near the work site allows them to, I guess, just more effectively and efficiently get prepared for their work day.

So I don't want to leave the impression that we're building a new building just to get a wash bay. That's not the case, but as part of our specifications of our new building, we always found that a wash bay is prudent. That's what we put in Stettler, we put in Drumheller, we put in Lloydminster, we put in Grande Prairie.

... But I want to caution that the wash bay is a vehicle bay that is -- has wash equipment in, but when we're -- when the crews all come in overnight and they're done putting their -- getting their trucks washed up, they all park equipment in there so that it's warm and ready for the work day and keep the snow off it. So it is used for multiple purposes.³³²

³²⁸ Exhibit 20555-X0019, AE-CCA-2015JUL20-018.

³²⁹ Exhibit 20555-X0004, PDF page 137.

³³⁰ Transcript, Volume 3, page 405, lines 10 to 16.

³³¹ Transcript, Volume 3, page 406, lines 9-17.

³³² Transcript, Volume 3, page 407, lines 1-3 and 10-23 and page 409, lines 7-13.

288. During the hearing, Mr. Howell elaborated further on the functions of a service truck bay and a project and construction bay:

The service truck bay would be -- the service group has some equipment, such as man lifts, and they would be insulated booms and that sort of thing that are sensitive to care and condition. And in order to keep them operational, we tend to try and store them inside.

Projects and constructions -- projects and construction is the group that does all of heavy construction work, so they'll have the big trucks, large insulated man lifts that will fit two mean and reach up to 80 feet. Maybe not that big in High Level, but certainly their truck and their live-line equipment and their digger derricks would be larger than that of the service groups, and their activities would be in that -- certainly they're going to put their trucks in their to keep them ready for work, but they're going to also be able to -- there might be some shop duties that they do in there.³³³

289. In an exchange with Commission counsel at the hearing, Mr. Howell provided the following evidence regarding the need for the service truck bay and the project and construction bay:

Q. Do you have these bays in the current facility?

A. MR. HOWELL: As I said before, we had two smaller bays, so we don't have the volume that we're looking for here, and that's a big piece of the expansion to the new building ...

Q. Well, if we talk about the service truck bays and the P&C truck bays, ATCO Electric doesn't currently have those in High Level, and they park or store these things outside; is that right?

A. MR. HOWELL: That's correct. And it's not a situation that we would ever want to be in. I mean, we've gotten there through past growth, and now we're further challenged by this structural deficiency in the building. And given that we're not looking to reduce or -- our people are there. We need the crews, and we want to give them the facilities that they -- that they need.

The congested parking in the yard, the inability to have a place to keep their trucks ready to go, certainly restricts them in the middle of the night. Or even at the start of a work day when they have to go and spend considerable time readying their truck for service rather than getting in it and starting to go. So it really affects their ability to respond.³³⁴

290. In response to an IR by the CCA,³³⁵ ATCO Electric provided an analysis of the potential costs and savings of having an on-site mechanics bay. The analysis showed an annual cost saving of \$9,900. During the hearing, Mr. Howell expanded on the benefits of having mechanics bays in the new building:

MR. HOWELL: That's correct. And, again, the mechanics, we feel that we'll get better service from them. The -- I think what we're trying to show here is that we're confident that the cost of the building -- the capital and the maintenance portions of the building that would be attributed to the mechanics' spaces would be saved back, or at least that we would at least be able to break even on that -- on costs with respect to the mechanic shop.

³³³ Transcript, Volume 3, page 411, lines 8-18.

³³⁴ Transcript, Volume 3, page 412, lines 5-9 and page 413, lines 11-25.

³³⁵ Exhibit 20555-X0019, AE-CCA-2015JUL20-019(a).

And at the same time get the better service and try to keep the trucks that -- the big trucks especially -- on the road. We wouldn't be putting mechanics into a spot where there was only a small service -- service trucks. But when we get into the big trucks and we get to the volumes that we've got here and in Rainbow Lake and we start wanting to get our mechanics closer to them and ...

And in this case since we're putting up a building in High Level at any rate and we're not going to spend any more, at least, by putting mechanics in High Level, then we feel we'll benefit to get the service level that we need and keep our trucks on the road better without -- without it costing us any more.

So the mechanics, again, are incremental to the new space. The real need is for the projects and construction people and the service people.³³⁶

291. The UCA argued that the High Level Service Building project does not meet the requirements of Criterion 1. To satisfy Criterion 1, projects must be of sufficient importance that the company's ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken. According to the UCA, the costs of capital additions that are not directly required to prevent deterioration in service quality and safety should be recovered solely through the I-X formula, and not through the capital tracker mechanism. The UCA pointed out that the new building has a considerably larger scope, occupying 35,893 sq. ft. as opposed to the 11,580 sq. ft. for the current building. The new building will also have five vehicle bays for the distribution function, including a wash bay, as compared to the current three bays (one of which is used by the transmission function). Additionally, the current building has no wash bay.³³⁷

292. The UCA submitted that ATCO Electric failed to provide evidence of any service quality or reliability issues associated with the use of the existing building through quantifiable measures such as service interruptions or response times. Moreover, the UCA argued that there will be no deterioration of service quality if ATCO Electric does not add a wash bay, as it is adequately functioning without a wash bay in its existing building by using a local car wash for washing its vehicles.³³⁸

293. Moreover, the UCA underscored the lack of a cost-benefit analysis in ATCO Electric's application to demonstrate the cost savings or benefits associated with adding features such as a wash bay, a meeting room, a lunch room/cafeteria, a fitness room, and a video/interview room.³³⁹

294. In its argument, the UCA made the following conclusions:

It is important to reiterate that Criterion 1 for Capital Tracker requires that the capital addition be required to prevent deterioration in service quality and safety. The prudence of the scope of capital additions for which Capital Tracker treatment is sought must be reviewed against that criterion, rather than a broader definition of "prudence" that may apply under a cost-of-service model. Contrary to what Mr. McNabb suggests, once you "determine if a project is in fact required for safe and reliable service" there is no further consideration of what "bells and whistles" should be added for purposes of the Capital Tracker application. The Capital Tracker mechanism is intended to provide additional revenues, above I-X, to utilities to ensure that service quality and safety can be

³³⁶ Transcript, Volume 3, page 416, line 13 to page 417, line 14.

³³⁷ Exhibit 20555-X0074, UCA argument, paragraphs 48-49.

³³⁸ Exhibit 20555-X0074, UCA argument, paragraphs 51 and 53.

³³⁹ Exhibit 20555-X0074, UCA argument, paragraph 55.

maintained – not improved, made more efficient, or modernized. That is not to say that projects that improve efficiency should not be undertaken by utilities; however, under PBR, it is not the Capital Tracker mechanism that is supposed to incent utilities to undertake those types of efficiency projects. Utilities have a general incentive to improve efficiency under the I-X formula (including through “add-ons” to projects required to maintain service quality and safety) “because they are able to retain the increased profits generated by those cost reductions or efficiency gains longer than they would under cost of service regulation.” [footnotes removed]

The UCA is of the view that the issue of “incrementalism” is particularly critical in the context of an economic downturn. Requiring customers, who may be facing difficult economic times, to pay for “bells and whistles” that are not required to maintain safe and reliable service, and which may result in efficiency savings or gains that are, in the short-term at least, retained by the utility, does not accord with the fundamental principles of PBR or with principles underlying competitive markets.³⁴⁰

295. The CCA similarly took issue with ATCO Electric’s construction of the additional wash and mechanics bays. The CCA submitted that evidence on the record indicates that service is not suffering from the lack of a wash bay; rather, ATCO Electric proposal constitutes an efficiency or service enhancement. Likewise, the CCA argued that the mechanics bays are being built largely to avoid out of town servicing, the annual cost of which is estimated to be \$21,000. The CCA submitted that since it has been ATCO Electric’s practice to wash its vehicles at local car washes and have its vehicles serviced externally, these costs are already incorporated in its going-in rates. Based on these reasons, the CCA recommended the capital costs of the mechanics service bays and the wash bay, which are 4,800 sq. ft. and 2,400 sq. ft., respectively, and the pro-rata share of central or shared facilities such as meeting rooms, washrooms and yard space, should not receive capital tracker treatment.³⁴¹

296. In argument, ATCO Electric submitted that the enhanced scope of the project is justified under Criterion 1:

The fact [that] operational needs have increased is understandable due to significant past growth. As well, ATCO Electric must consider its ability to serve moderate future growth over the near to mid-term. As Mr. Howell indicated “...we've grown our crews. We haven't grown our space for 15 years and we're crowded.” It would not make much sense to replace the existing building exactly as is given the existing and future demands placed on it. A replacement facility should be designed to also accommodate reasonable near term growth needs.³⁴² [footnotes omitted]

297. ATCO Electric explained that the incremental cost of adding mechanics bays is reasonable in light of past growth alone, along with the added difficulty of finding mechanics in High Level. ATCO Electric noted that having a mechanics bay would result in vehicles being repaired on-site, and subsequently faster, which would make the vehicles more available for its crew, and thereby improve the turnover time for new customer extensions, trouble shooting and repairing outages.³⁴³ ATCO Electric added that the size of the proposed service truck bay, and projects and construction garage bay, illustrates the variety and volume of equipment that is

³⁴⁰ Exhibit 20555-X0074, UCA argument, paragraphs 60-61.

³⁴¹ Exhibit 20555-X0076, CCA argument, paragraph 83.

³⁴² Exhibit 20555-X0075, ATCO Electric argument, paragraph 80.

³⁴³ Transcript, Volume 3, page 420, line 16 to page 421, line 5.

staged out of High Level into the surrounding service area, as a result of the growth experienced in this area over the past several years.³⁴⁴

298. With regards to the wash bay, ATCO Electric submitted that it is a necessary aspect of utility operations. ATCO Electric argued that the inclusion of a wash bay is a standard feature of a service centre the size of High Level, and that this should not disqualify it from K factor funding where I-X funding is insufficient, given that it avoids a deterioration of service levels or quality and its design and cost are reasonable. ATCO Electric pointed out that the wash bay serves several additional purposes: first, as a bay to work on issues associated with large equipment, including overnight storage in adverse weather conditions; second, to ensure timely access to private and public lands by cleaning vehicles to prevent clubroot; and, third, to clean utility equipment which, due to High Level's remote location, experiences significant off-road use, and consequently accumulates large amounts of mud.³⁴⁵

299. In its reply argument, ATCO Electric also referenced Mr. Howell's evidence during the hearing to explain that, given the bay will be used to store vehicles overnight, the incremental cost of the wash bay would be limited to the cost of the washing equipment, which is considerably less than the \$0.7 million required to outfit the bay. Therefore, ATCO Electric concluded, "the incremental cost of outfitting the garage bay to perform this required function is de minimis relative to the \$23.9 million cost of this building."³⁴⁶

300. In respect of the UCA's concerns regarding the addition of meeting rooms, a lunch room/cafeteria, and a video/interview room, ATCO Electric argued that the existing High Level building also has these features and that the UCA provided no rationale as to why these rooms are no longer required in the new building. ATCO Electric also expressed the view that the UCA's attempts to parse a utility asset into smaller components for assessment as a capital tracker would be micro-management that "would invariably lead to unnecessary (and increasing) regulatory burden for all parties, which is unreasonable and contrary to the Principle 3 of PBR."³⁴⁷

Commission findings

301. The Commission is persuaded by the evidence of Manasc Isaac Architects and Engineers that a new building is required in the near term, especially in light of its recommendation "... that ATCO Electric not continue to use the building and also not reuse the building for a closed storage building."³⁴⁸ The Commission also accepts the evidence submitted by ATCO Electric with regard to the spatial constraints in its existing building, including Mr. Howell's testimony where he states, "[s]o we've grown our crews. We haven't grown our space for 15 years, and we're crowded."³⁴⁹ The Commission finds that ATCO Electric has demonstrated that the growth in High Level in the past few years has necessitated an increased staff complement,³⁵⁰ which has resulted in spatial constraints, and that the condition of the building is such that it needs to be replaced. Accordingly, the Commission finds the need for the High Level

³⁴⁴ Exhibit 20555-X0075, ATCO Electric argument, paragraph 81.

³⁴⁵ Exhibit 20555-X0075, ATCO Electric argument, paragraph 83.

³⁴⁶ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 33.

³⁴⁷ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 35.

³⁴⁸ Exhibit 20555-X0080, PDF page 145.

³⁴⁹ Transcript, Volume 3, page 405, lines 15-16.

³⁵⁰ Exhibit 20555-X0004, PDF pages 177, 179-180.

service building is reasonable. Given the condition of the existing building, as evident by the report of Manasc Isaac Architects and Engineers, the Commission also finds the timing of the project, which will be completed by 2017, to be reasonable.

302. Both the CCA and the UCA raised concerns regarding the scope of the new building at High Level. Based on ATCO Electric's evidence, the Commission understands that the majority of the increase in space, from 11,580 sq. ft. to 35,893 sq. ft., is related to additional garage bays.³⁵¹ The UCA and the CCA primarily contested the need for the new mechanics bays and wash bay. The UCA raised an additional issue regarding the need for a meeting room, lunch room/cafeteria, fitness room, and video/interview room in the new building.

303. The Commission finds that scope of the entire project is reasonable given the deficiencies in the existing building, the growth experienced in this area over the past several years and the modest growth forecast for the future.

304. Based on the evidence on the record, the Commission is not persuaded by the UCA's arguments against the inclusion of the meeting room, lunch room/cafeteria, fitness room, and video/interview room in the new building. As confirmed by ATCO Electric, the existing building also has these features³⁵² and the UCA's argument does not sufficiently explain why these rooms are no longer required in the new building.

305. The Commission does not share the UCA's and the CCA's concerns regarding the wash and mechanics bays. The Commission notes that ATCO Electric's cost-benefit analysis supports on-site mechanics bays.³⁵³ The Commission finds that given the remoteness of High Level, having on-site mechanics bays supports the delivery of safe and reliable service. Presently, fleet maintenance and condition assessments for vehicles in the High Level, Rainbow Lake, Fox Lake and LaCrete areas are managed and supported by ATCO Electric's Peace River shop, which is 300 kilometres (km) from High Level. As described by ATCO Electric, relying on mechanics located in Peace River results in delays which negatively impact its ability to provide safe and reliable service:

To take equipment to Peace River, a driver or equipment operator would use one or two full days ferrying the equipment to the shop; and then would have to either wait for it or make another round trip to pick it up. When this equipment is out of service for several days longer than it needs to be, staff require additional spare vehicles or are unable to perform work in the field.³⁵⁴

306. The Commission is also persuaded that it is reasonable to have an on-site wash bay, given that the utility equipment operating out of High Level accumulates large amounts of mud from off-road activities. The Commission finds that the wash bay will assist in maintaining ATCO Electric's fleet, and reduce the spread of clubroot. The wash bay also serves additional purposes, as it will be used as a bay to work on large equipment, and for overnight storage in adverse weather conditions.

³⁵¹ Exhibit 20555-0019, AE-CCA-2015JUL20-018.

³⁵² Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 35.

³⁵³ Exhibit 20555-X00019, AE-CCA-2015JUL20-019(a).

³⁵⁴ Exhibit 20555-X00019, AE-CCA-2015JUL20-019(d).

307. Consequently, the Commission finds the forecast scope, level and timing of the project for 2017 to be reasonable. ATCO Electric's forecast capital additions associated with the distribution function of this project are \$19.4 million for 2017. The Commission has reviewed the costs of the forecast capital additions in light of the evidence supporting these costs, including the breakdown of individual cost components,³⁵⁵ and finds the forecast costs to be reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this program satisfies the project assessment requirement of Criterion 1.

6.2.3.7 Fox Creek Service Building

308. ATCO Electric applied for capital tracker treatment for the construction of a 5,921 sq. ft. service building in the Town of Fox Creek, Alberta, which is approximately 260 km northwest of Edmonton. The project includes the planning, design, land purchase, and construction of a new facility.³⁵⁶ Construction of the Fox Creek Service Building will begin in May 2016 and will be completed in April 2017.³⁵⁷ ATCO Electric provided a business case in Appendix B Part 2, Business Case B.7.³⁵⁸

309. In its business case, ATCO Electric provided information to demonstrate high levels of growth in its asset counts and capital activity in the Fox Creek area over the past several years.³⁵⁹

310. ATCO Electric submitted that gas and oil activity around Fox Creek is driving customer growth as the community sits on two massive oil plays. The Duvernay and Montney shale plays are projected to cause the population to double in size over the next five years, as the drilling phase nears completion and producers move into the production phase to extract natural gas liquids. ATCO Electric projected the number of staff required in Fox Creek to grow from a current staff complement of five to 12 by 2020.³⁶⁰

311. ATCO Electric explained that its current facility at Fox Creek is ineffective and inadequate for sustained use, as the office and garage bays were built for residential use in 1972 and cannot be expanded or renovated any further to accommodate its existing staff or projected additions, including a new construction line crew. Furthermore, the lack of sufficient yard space for material storage or fleet vehicles results in longer response times as its staff has to drive to Valleyview or High Prairie when it requires a bucket truck.³⁶¹

312. After conducting a needs assessment, ATCO Electric determined the following spatial deficiency in its existing facility, which is shown in the table below:

³⁵⁵ Exhibit 20555-X0004, PDF page 127.

³⁵⁶ Exhibit 20555-X0004, PDF page 186.

³⁵⁷ Exhibit 20555-X0004, PDF page 197.

³⁵⁸ Exhibit 20555-X0004, PDF page 185.

³⁵⁹ Exhibit 20555-X0004, PDF pages 211-212.

³⁶⁰ Exhibit 20555-X0004, PDF page 213.

³⁶¹ Exhibit 20555-X0004, PDF pages 189 and 193.

Table 25. Existing and required spatial needs for Fox Creek³⁶²

Space	Current 2015	Required 2020	Space shortfall
	(sq. ft.)		
Owned office	942	1,921	979
Owned garage bays	588	4,000	3,412
Total building area	1,530	5,921	4,391

313. ATCO Electric also provided an analysis of the various alternatives that it had considered such as renovating and expanding the existing facility, and purchasing or leasing a new facility. ATCO Electric's analysis included explanations as to why none of the aforementioned alternatives were feasible, along with the results of the search for buildings to lease or purchase and how the buildings identified failed to meet ATCO Electric's business requirements.³⁶³

314. ATCO Electric also provided details of project capital expenditures and additions in its business case. It forecast its capital addition to be \$4.7 million for 2017.³⁶⁴

315. Mr. Bell, on behalf of the UCA, raised concerns about ATCO Electric's projections of growth in Fox Creek in light of the current economic downturn. He stated:

AE defends its proposal by referring to shale oil projects. In the same CBC article discussed above, the author makes reference to the fact that Saudi Arabia appears to be trying to push shale oil out of the market. There is no evidence that AE has considered the impact of this Saudi Arabian effort on economic conditions in Fox Creek. The prudent course would be to defer this project, until the outlook was clearer.³⁶⁵

316. ATCO Electric responded to these submissions, arguing:

33. Activities in Fox Creek remain robust. ATCO Electric notes that projects in the condensate-rich Montney/Duvernay region are still proceeding. These include the Fox Creek 741S Capacity Upgrade, the Muir POD, and the Simonette 733S Substation Capacity Upgrade.

34. ATCO Electric monitors its customers' project status regularly. The following table confirms that, based on data to September 2015, there have been no significant changes in total forecast operating load or forecast site counts in the Fox Creek area relative to the June 2015 data provided in the Fox Creek Service Building business case¹². In fact, the data indicates that the forecast site count has actually increased from 185 (based on June 2015 data) to 222 (based on September 2015 data). Consequently, there is no evidence to warrant and changes to the 2017 completion date of the Fox Creek Service Building.³⁶⁶

³⁶² Exhibit 20555-X0004, PDF page 189.

³⁶³ Exhibit 20555-0023, AE-AUC-2015JUL20-025 and Exhibit 20555-X0004, PDF page 199.

³⁶⁴ Exhibit 20555-X0004, PDF page 196.

³⁶⁵ Exhibit 20555-X0026, UCA evidence, A20.

³⁶⁶ Exhibit 20555-X0042, ATCO Electric rebuttal evidence.

Commission findings

317. ATCO Electric requested capital tracker treatment for the Fox Creek Service Building project on a forecast basis in 2017. The Commission has reviewed the business case and the evidence on the record with regards to the historical and expected future growth experienced in Fox Creek.³⁶⁷ The Commission finds that Fox Creek has undergone significant growth in the past few years, resulting in higher levels of investment on behalf of ATCO Electric. Regardless of the level of future economic growth in the near term, the Commission agrees that the existing building is at the end of its useful life and not fit for industrial use. Additionally, the Commission finds that the building lacks sufficient yard space to adequately support ATCO Electric's material storage and fleet vehicles.³⁶⁸ In light of the above considerations, the Commission finds that the information provided by ATCO Electric supports a finding that the project is required during the 2017 forecast period to maintain service reliability and safety at adequate levels. The Commission accepts generally the evidence provided in ATCO Electric's business case indicating that the company has a current and future shortage of facility space.

318. With respect to the scope, level and timing of this project for 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2017 to be reasonable. Specifically, the scope and level of the Fox Creek Service Building project is supported by ATCO Electric's business case that explains this project is being undertaken to address a shortage in facility space in light of the significant historical and future projections of growth, and issues within its existing facility. The Commission finds the timing of this project is supported by the needs assessment conducted by ATCO Electric, which shows ATCO Electric is currently facing a space deficit.³⁶⁹

319. ATCO Electric's forecast capital additions associated with this project are \$4.7 million for 2017. The Commission has reviewed the costs of the forecast capital additions in light of the evidence supporting these costs, including the breakdown of individual cost components,³⁷⁰ and finds the forecast costs to be reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision.

320. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Fox Creek Service Building project are reasonable as proposed for 2017, subject to the adjustments applicable to all projects set out in Section 6.1.1.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this program satisfies the project assessment requirement of Criterion 1.

6.2.4 Information Technology Related

321. The Information Technology (IT) Related program is an annual recurring program and consists of several IT-related projects.

322. In Proceeding 3218, ATCO Electric requested approval for three IT-related groups of projects (subprograms), which in turn are composed of related projects. The subprograms applied

³⁶⁷ Exhibit 20555-X0004, PDF pages 211-212 and Exhibit 20555-X0042, ATCO Electric rebuttal evidence, paragraphs 33-34.

³⁶⁸ Exhibit 20555-X0004, PDF pages 190, 193-194 and 200.

³⁶⁹ Exhibit 20555-X0004, PDF page 189.

³⁷⁰ Exhibit 20555-X0004, PDF page 196.

for in Proceeding 3218 were the IT Operational System Extension subprogram, the IT Enterprise System Technology subprogram and the Industry Driven IT subprogram. In Decision 3218-D01-2015, the Commission found that the IT Operational System Extension subprogram did not satisfy the project assessment requirement of Criterion 1 and denied capital tracker treatment for this subprogram in 2013, 2014 and 2015.³⁷¹ In this application, ATCO Electric did not reapply for capital tracker treatment of the IT Operational System Extension subprogram.

323. In the application, ATCO Electric requested approval for two IT-related subprograms as presented in Table 26 below. Within the IT Enterprise System Technology subprogram, ATCO Electric requested approval for the 2014 true-up and the 2016 and 2017 forecasts for its previously approved capital tracker projects, and also requested approval for capital tracker treatment for three new projects: Voice & Data Network Upgrade, Mobile Hardware Upgrade and Meter Data Management (MDM) System Upgrade. Assessments of this subprogram and associated projects with respect to the project assessment requirement of Criterion 1 are discussed in Section 6.3.2.1. Within the Industry Driven IT subprogram, ATCO Electric requested approval for the 2014 true-up and the 2016 and 2017 forecasts for its previously approved capital tracker projects. No new projects were applied for in this subprogram. Assessments of the Industry Driven IT subprogram and its associated projects with respect to the project assessment requirement of Criterion 1 are discussed in Section 6.3.2.2.

Table 26. 2014 to 2017 Information Technology Related program capital additions³⁷²

Subprogram description	Capital additions (\$ million)					
	2014 approved	2014 actual	2015 approved	2015 update	2016 forecast	2017 forecast
IT Enterprise System Technology	7.7	7.4	2.7	4.8	4.6	8.6
Industry Driven IT	4.0	1.9	2.7	7.6	4.8	0.8
IT Related program total	11.7	9.3	5.4	12.4	9.4	9.4

6.2.4.1 IT Enterprise System Technology

Previously approved capital tracker projects

324. The purpose of the IT Enterprise System Technology subprogram is to upgrade information technology infrastructure, business software applications and database management systems in order to minimize service disruptions to systems that support critical operations. Projects that were approved for capital tracker treatment in Decision 3218-D01-2015 included an upgrade to Windows 7, upgrades to the Outage Management System and a replacement of the Health and Safety system to be compatible with the Windows 7 operating environment, an Oracle eBusiness upgrade, and a project to move ATCO Electric's customer care and billing system (CIS) from the current mainframe platform to a distributed platform.

325. The Commission approved the need for the IT Enterprise System Technology subprogram as part of the project assessment under capital tracker Criterion 1, in Decision 3218-D01-2015³⁷³ for 2013, 2014 and 2015, based on the projects identified by ATCO Electric in that

³⁷¹ Decision 3218-D01-2015, paragraph 241.

³⁷² Exhibit 20555-X0004, Appendix B – Part 2, IT Related Program Preamble, page 3, Table 2.

³⁷³ Decision 3218-D01-2015, paragraph 254.

proceeding. ATCO Electric provided updates to its business cases originally filed in Proceeding 3218, as indicated in Table 27 below.

Table 27. 2014 to 2017 IT Enterprise System Technology projects capital additions³⁷⁴

Project description	Document filed		Capital additions (\$ million)					
			2014 forecast	2014 actual	2015 forecast	2015 updated	2016 forecast	2017 forecast
Annual Initiatives	Appendix B	C.2 Sub-Program Update	0.8	0.5	1.9	1.8	3.7	0.9
CIS Re-Platforming	Appendix C.2.1	Project Completion Summary	2.2	2.2	--	--	--	--
Oracle eBusiness Upgrade	Appendix C.2.2	Project Completion Summary	3.3	3.4	--	--	--	--
Health and Safety System Replacement	Appendix C.2.3	Project Completion Summary	0.7	0.4	--	--	--	--
Windows 7 Upgrade	Appendix C.2.4	Project Update	0.7	0.9	0.0	0.3	--	--
Outage Management System Upgrade	Appendix C.2.5	Project Update	--	--	0.8	0.0	0.0	1.0

326. The total 2014 approved forecast capital additions for the IT Enterprise System Technology subprogram were \$7.7 million, while the total actual 2014 capital additions were \$7.4 million, resulting in a negative \$0.3 million variance. ATCO Electric explained the variance on a project by project basis. ATCO Electric noted that the \$0.3 million variance and the \$0.2 million variance for the Health and Safety System Replacement project and the Windows 7 upgrade project, respectively, were due to changes in scope.^{375 376} ATCO Electric did not provide explanations for the remaining projects with variances, because the project variances were within the Rule 005 variance reporting threshold.³⁷⁷

327. Regarding the prudence of its actual 2014 capital additions, ATCO Electric confirmed that the 2014 work for this subprogram was completed in accordance with its formal project management policies and procedures, as described in the application, and further submitted that the 2014 capital additions “were reasonably and prudently incurred in the provision of safe and reliable electrical distribution service.”³⁷⁸

328. The forecast capital additions for the Annual Initiatives projects for 2016 and 2017 of \$3.7 million and \$0.9 million, respectively, are based on the forecast timing of vendor product upgrade release dates and historical upgrade costs. ATCO Electric provided a list of its Annual Initiative projects for 2016 and 2017, which showed that the 2016 forecast capital expenditures of \$3.7 million were mostly attributed to an Oracle database upgrade.³⁷⁹

329. The forecast capital additions for the Outage Management System Upgrade project for 2017 is \$1.0 million. ATCO Electric explained that capital expenditures for this project will be

³⁷⁴ Exhibit 20555-X0004, Appendix B – Part 2, C.2 – IT Enterprise System Technology, page 3, Table 1.

³⁷⁵ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.3 Health and Safety System Replacement, page 3.

³⁷⁶ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.4 Windows 7 Upgrade, page 4, Table 3.

³⁷⁷ Exhibit 20555-X0004, Appendix B – Part 2, C.2 – IT Enterprise System Technology – Appendix B, page 2 and Appendix C.2.2 Oracle eBusiness Upgrade, page 3.

³⁷⁸ Exhibit 20555-X0004, Appendix B – Part 2, C.2 – IT Enterprise System Technology – Appendix B, page 2.

³⁷⁹ Exhibit 20555-X0004, Appendix B – Part 2, C.2 – IT Enterprise System Technology – Appendix B, pages 4-5.

moved from 2015 to 2017 because an upgrade to the Outage Management System is no longer required in 2015 and, accordingly, ATCO Electric has revised its plan to upgrade this system in 2017.³⁸⁰

330. ATCO Electric confirmed that the scope, nature, and driver for the IT Enterprise System Technology projects in 2016 and 2017 have not changed since their approval in Decision 3218-D01-2015.³⁸¹

New capital tracker projects

331. ATCO Electric provided business cases for several new projects, as indicated in the table below:

Table 28. 2014 to 2017 IT Enterprise System Technology new projects capital additions³⁸²

Project description	Document filed		Capital additions (\$ million)					
			2014 forecast	2014 actual	2015 forecast	2015 updated	2016 forecast	2017 forecast
Voice & Data Network Upgrade	Appendix C.2.6	Business Case	-	-	-	1.7	0.6	-
Mobile Hardware Upgrade	Appendix C.2.7	Business Case	-	0.0	-	1.0	0.3	-
Meter Data Management System Upgrade	Appendix C.2.8	Business Case	-	-	-	-	-	6.7

Voice & Data Network Upgrade

332. The purpose of the Voice & Data Network Upgrade project is to replace existing voice and data communication technologies that are not meeting current industry standards and are being phased out by vendors. ATCO Electric submitted that upgrades to these networks are required to provide timely and reliable information, such as connectivity maps and work orders to field-based staff, to maintain the reliability and safety of the distribution system.³⁸³

333. ATCO Electric forecast capital additions for the Voice & Data Network Upgrade project at \$1.73 million in 2015 and \$0.60 million in 2016, based on replacing existing analogue voice radio devices with digital voice radio devices, upgrading the data network in district offices, and upgrading the Vegreville Distribution Operations Centre telecommunication links.³⁸⁴

334. In response to Commission IRs, ATCO Electric submitted that its data communication requirement has increased significantly over time, due to the growth of its distribution network and the implementation of business applications to support field operations. Based on an assessment of its voice and data network in 2014, ATCO Electric determined that several of its service locations lacked the required data network capacity to meet its operational needs,³⁸⁵ that

³⁸⁰ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.5 Outage Management and Workforce Management System Update, page 4.

³⁸¹ Exhibit 20555-X0004, Appendix B – Part 2, C.2 – IT Enterprise System Technology, page 2.

³⁸² Exhibit 20555-X0004, Appendix B – Part 2, C.2 – IT Enterprise System Technology, page 3, Table 1.

³⁸³ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.6 Voice and Data Network Upgrade, pages 1 and 4.

³⁸⁴ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.6 Voice and Data Network Upgrade, pages 3-4.

³⁸⁵ Exhibit 20555-X0023, AE-AUC-2015JUL20-032(c).

“the data capacity of the network in 61% of the service locations were below the cellular bandwidth of a regular household,” and that the network technology currently in place was “not designed for businesses that are required to send large volumes of data to remote locations.”³⁸⁶ To illustrate the effect of the upgrade, ATCO Electric compared the current amount of time that it takes to update maps for all computers on the current network, which is 10 days, with an expected time of 4.5 hours once the upgraded network in place.³⁸⁷

335. During the hearing, in discussion with Commission counsel, Mr. Claude, on behalf of ATCO Electric described how untimely map updates impact the safety and reliability of its distribution system:

MR. CLAUDE: ... The electrical system is a very dynamic system. We're requiring a very high reliance on electrical information to be able to operate the system.

These servicemen and others who utilize this information, they need to have the best information at their fingertips at all times to make sure they can operate effectively and safely on that electrical system. Without that, there is significant risk in service reliability and safety of the workers.

Q. So the electrical information you're talking about, does that change daily?

A. MR. CLAUDE: Absolutely. We would have in the neighbourhood of, you know, 1600 to 2,000 projects on the system over the course of the year, which can have many changing system dynamics.

We have in the neighbourhood of about 20,000 outages on an annual basis, which, again, result in different changing system configurations. ...³⁸⁸

336. In argument, the CCA submitted that the Voice & Data Network Upgrade project does not qualify as a capital tracker project for a number of reasons:

Since the business objective is to provide updated maps, those costs are already included in O&M. Secondly, the network will provide enhanced service which does not qualify for capital tracker treatment. Third, it is not clear why updates cannot be sent via inter-office mail between head office and the various units.³⁸⁹

337. ATCO Electric responded to the CCA's reasons as to why the Voice & Data Network Upgrade project does not qualify as a capital tracker project. ATCO Electric submitted that the project is required “to ensure that critical system information is transmitted to field operations on a timely basis in order to maintain the safe and reliable operation of the distribution system,” and includes the transmission of data required to update maps. ATCO Electric did not agree with the CCA's characterization of the upgraded network as an enhanced service, submitting that the growth in size and complexity of the distribution system necessitates the need to transmit information on a daily basis to safely and reliably operate the distribution system. Finally, ATCO Electric submitted that sending updates via inter-office mail is not a reasonable alternative.³⁹⁰

³⁸⁶ Exhibit 20555-X0023, AE-AUC-2015JUL20-031(c).

³⁸⁷ Exhibit 20555-X0023, AE-AUC-2015JUL20-032(a).

³⁸⁸ Transcript, Volume 3, page 429, line 9 to page 426, line 1 (Mr. Claude).

³⁸⁹ Exhibit 20555-X0076, CCA argument, paragraph 43.

³⁹⁰ Exhibit 20555-X0080, ATCO Electric reply argument, paragraphs 68-73.

Mobile Hardware Upgrade

338. The purpose of the Mobile Hardware Upgrade project is to replace the data modems and docking stations of laptop computers in ATCO Electric's service vehicles to make the mobile hardware compatible with its service provider's technology upgrades. ATCO Electric submitted that these replacements are required to ensure its operations, regulatory compliance and customer satisfaction are not negatively impacted.³⁹¹

339. ATCO Electric forecast capital additions for the Mobile Hardware Upgrade project at \$0.97 million in 2015 and \$0.34 million in 2016.³⁹²

340. The CCA and the UCA did not raise any concerns in regards to the Mobile Hardware Upgrade project.

Meter Data Management (MDM) System Upgrade

341. The purpose of the MDM System Upgrade project is to significantly upgrade ATCO Electric's MDM system, and includes changes required to business applications that use meter data, such as load profiling and settlement, and customer care and billing. ATCO Electric explained that its current version will not be supported by the vendor after March 2018 and, because the new version has been completely re-architected, the upgrade effort will be extensive. ATCO Electric submitted that the upgrade is required to ensure its operations, regulatory compliance and customer satisfaction are not negatively impacted.³⁹³

342. ATCO Electric forecasted capital additions for this project of \$6.7 million in 2017, and estimated capital expenditures of \$0.74 million in 2015, \$3.22 million in 2016 and \$2.74 million in 2017, based on input from the vendor and industry consultants who have experience with similar upgrades. In the application, ATCO Electric submitted that the 2015 capital expenditures were estimated to be within plus or minus 10 per cent of the expected actual expenditures, and that the 2016 and 2017 capital expenditures were estimated to be within the range of minus 50 per cent to plus 100 percent of the expected actual expenditures.³⁹⁴

343. In response to a Commission IR, ATCO Electric explained that it had not considered any alternatives for this project, and would not consider alternate solutions unless the current vendor application could not satisfy its business needs.³⁹⁵ During questioning by Commission counsel regarding ATCO Electric's statement that there are no reasonable alternatives other than proceeding with the vendor-supported upgrades, ATCO Electric described the complexity of IT systems, in general, and submitted that to minimize costs, challenges, and the risk to the project schedule, experience has shown that remaining with the current vendor is prudent. Furthermore, ATCO Electric confirmed that based on its completed fit/gap analysis, the current system, with the applied for improvements, will satisfy its business needs.³⁹⁶

³⁹¹ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.7 Mobile Hardware Upgrade, pages 2 and 4.

³⁹² Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.7 Mobile Hardware Upgrade, page 3.

³⁹³ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.8 Meter Data Management System Upgrade, pages 2-3 and 8.

³⁹⁴ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.8 Meter Data Management System Upgrade, page 7.

³⁹⁵ Exhibit 20555- X0023, AE-AUC-2015JUL20-033(b).

³⁹⁶ Transcript, Volume 3, page 437, line 2 to page 441, line 4 (Mr. Claude).

344. In the business case for the MDM System Upgrade project, ATCO Electric provided brief descriptions of the project's planning and scoping Phase 1 deliverables and detailed planning and design Phase 2 deliverables, noting that the project costs and effort would be refined when more detailed information is available at the end of the solution design stage.³⁹⁷ During the hearing, when asked for an update on the project, ATCO Electric confirmed that Phase 1 was complete but that the estimate had not been refined and remained in the plus 100 per cent range.³⁹⁸

345. Neither the UCA nor the CCA commented on the MDM System Upgrade project in their respective arguments and reply arguments.

Commission findings

346. In Decision 3218-D01-2015, the Commission approved the need for the IT Enterprise System Technology subprogram for capital tracker treatment for 2013-2015. The group included the following projects: Annual Initiatives, CIS Re-Platforming, Oracle eBusiness Upgrade, Health and Safety System Replacement, Windows 7 Upgrade and Outage Management System Upgrade. Further, the Commission determined the actual scope, level, timing and costs for these projects in 2013 to be prudent and the forecast scope, level, timing and costs for these projects for 2014 and 2015 to be reasonable. Therefore, the Commission has previously determined that these projects satisfied the project assessment requirement of Criterion 1.

347. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the IT Enterprise System Technology group of projects filed in Proceeding 3218 were not required in 2014.

348. With respect to the scope, level and timing of these projects carried out in 2014, the Commission has reviewed ATCO Electric's 2014 actual capital additions associated with these projects and, in consideration of the variances due to changes in scope, as explained above, the Commission finds that they are generally consistent with the scope, level and timing of the work outlined in the business cases for this capital tracker and approved in Decision 3218-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for these projects in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

349. In the present application, ATCO Electric also requested capital tracker treatment for the IT Enterprise System Technology subprogram on a forecast basis in 2016 and 2017. The subprogram included two previously applied-for projects: Annual Initiatives and Outage Management System Upgrade, and three new projects: Voice & Data Network Upgrade, Mobile Hardware Upgrade and MDM System Upgrade. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for

³⁹⁷ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.8 Meter Data Management System Upgrade, pages 5-7.

³⁹⁸ Transcript, Volume 3, page 440, line 6 to page 441, line 22 (Mr. Claude).

purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Annual Initiatives and Outage Management System Upgrade projects are not required to continue in 2016 or 2017.

350. With respect to the scope, level and timing of the previously approved projects for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record and finds the forecast scope, level and timing of the projects for 2016 and 2017 to be reasonable. ATCO Electric's forecast capital additions associated with Annual Initiatives and Outage Management System Upgrade projects are \$3.7 million in 2016 and \$1.9 million in 2017. The Commission has reviewed the information supporting ATCO Electric's forecasts and finds the total annual cost forecasts, which were based on ATCO Electric's forecast timing of vendor product upgrade release dates and historical upgrade costs, to be reasonable.

351. ATCO Electric forecast capital additions for the Voice & Data Network Upgrade project of \$0.60 million in 2016. The CCA raised concerns with the Voice & Data Network Upgrade project as noted above, and submitted that this project does not qualify as a capital tracker project. The Commission has reviewed the business case provided by ATCO Electric and the evidence on the record with respect to the Voice & Data Network Upgrade project and finds that the information provided by ATCO Electric supports a finding that the project is required during the 2016 forecast period to maintain service reliability and safety at adequate levels for the reasons below.

352. The Commission does not agree with the CCA that the purpose of this project is limited to providing updated maps and that the project can be considered to be an enhanced service. ATCO Electric submitted that the technologies currently in place are out-dated and accordingly being phased out by vendors. ATCO Electric provided evidence regarding its current need to upgrade its voice network, which has been in service for over 27 years, to reduce the risk of increased and extended failures. It also provided evidence to show that its current data network is not capable of adequately addressing the increasing network capacity requirements to provide updated information, such as maps and work orders to its field offices.³⁹⁹ The Commission accepts ATCO Electric's position that the upgrades are required to maintain service reliability and safety at adequate levels.

353. Regarding the CCA's third reason as to why the Voice & Data Network Upgrade project does not qualify as a capital tracker project, the Commission accepts ATCO Electric's submission that sending map updates via inter-office mail is not a reasonable alternative, considering the evidence provided by ATCO Electric regarding the amount of data involved and the requirement for daily updates.

354. ATCO Electric forecasted capital additions for the Mobile Hardware Upgrade project of \$0.34 million in 2016. The Commission has reviewed the business case provided by ATCO Electric and the evidence on the record with respect to the Mobile Hardware Upgrade project and considers the evidence provided by ATCO Electric supports a finding that the project is required during the 2016 forecast period to maintain service reliability and safety at adequate levels.

³⁹⁹ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.2.6 Voice and Data Network Upgrade, pages 1-4 and Exhibit 20555-X0023, AE-AUC-2015JUL20-032.

355. With respect to the scope, level and timing of the Voice & Data Network Upgrade and Mobile Hardware Upgrade projects for 2016, the Commission has reviewed the business case and the relevant portions of the record for the projects and finds the forecast scope, level and timing of the projects for 2016 and 2017 to be reasonable. ATCO Electric's forecast capital additions for 2016 associated with the Voice & Data Network Upgrade and the Mobile Hardware Upgrade projects are \$0.6 million and \$0.3 million, respectively. No capital additions are forecast for the projects for 2017. The Commission has reviewed the information supporting ATCO Electric's forecasts and finds the forecast costs to be reasonable.

356. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Annual Initiatives, Outage Management System Upgrade, Voice & Data Network Upgrade and Mobile Hardware Upgrade projects are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that these projects satisfy the project assessment requirement of Criterion 1.

357. ATCO Electric forecasted capital additions for the MDM System Upgrade project of \$6.7 million in 2017. The Commission has reviewed the business case provided by ATCO Electric and the evidence on the record with respect to the MDM System Upgrade project. Given that the current version of the MDM system will not be supported by the vendor after March 2018 and that the upgrade is required to ensure ATCO Electric's operations, regulatory compliance and customer satisfaction are not negatively impacted, the Commission considers that the evidence provided by ATCO Electric supports a finding that the project is required during the 2017 forecast period to maintain service reliability and safety at adequate levels.

358. With respect to the timing of the MDM System Upgrade project for 2017, the Commission has reviewed the business case and the relevant portions of the record for the project and finds the forecast timing of the project for 2017 to be reasonable.

359. ATCO Electric confirmed in the hearing that the planning and scoping phase of the project was complete. The Commission observes that according to ATCO Electric's estimation methods, as reproduced in Table 29 below, the estimation accuracy for a project in the planning and scoping stage is expected to be in the +50/-33 per cent range. However, ATCO Electric confirmed in the hearing that the estimation accuracy for this project is in the +100 per cent range.

Table 29. Estimating Types – IT Development⁴⁰⁰

Estimate type		Project maturity (% of scope definition)	Project stage	Techniques	Accuracy
1	Order of magnitude	10-30%	Feasibility study/strategy development	Parametric & Analogous	+100/-50%
2	Budgetary	30-70%	Planning & scoping and conceptual design	Analogous	+50/-33%
3A	Definitive – Stage 1	70-90%	Detailed solution design	Bottom Up	+/-10%
3B	Definitive – Stage 2	90-100%	Project development & implementation	Bottom Up	+10/-5%
4	Actual	100%	Project complete	Actual	+/-0%

360. Based on the stated complexity of the project, the requirement to make changes to several other business applications, and the inability of ATCO Electric to refine its estimate after completing the scoping and planning phase, the Commission finds the forecast scope, level and cost of the project have not been sufficiently established to allow it to make a determination on whether this project satisfies all the project assessment requirements of Criterion 1. Therefore, the MDM System Upgrade project of the IT Enterprise System Technology subprogram is denied capital tracker treatment at this time.

6.2.4.2 Industry Driven IT

361. The Industry Driven IT subprogram consists of projects driven by external parties including the AUC, the Alberta Electric System Operator (AESO) and Measurement Canada. ATCO Electric noted that these IT projects will enable ATCO Electric to remain in regulatory compliance with the AUC, the AESO and Measurement Canada rules and regulations by making changes to ATCO Electric's policies and processes and by extending the functionality of ATCO Electric's business applications.⁴⁰¹ ATCO Electric explained that rule changes usually involve technical changes to one or more applications that are integrated to support complicated end to-end business processes.

362. ATCO Electric indicated that without these projects it will remain heavily reliant on manual processes which are subject to human error. Given the volume of data and complexity, it may be unable to deliver critical industry processes and services as mandated by government and associated agencies.⁴⁰²

363. ATCO Electric explained that each year regulatory bodies announce changes, set compliance dates and direct the distribution utilities to comply accordingly. Once directed, ATCO Electric initiates an IT project to address the regulatory requirements.⁴⁰³ ATCO Electric identified two Industry Driven IT projects in this application; first, an Annual Initiatives project consisting of projects required to remain compliant with AUC rules; and second, a Measurement Compliance project that addresses changes required to comply with Measurement Canada's S-S-

⁴⁰⁰ Exhibit 20555-X0007, application, paragraph 64, Table 2.

⁴⁰¹ Exhibit 20555-X0004, Appendix B – Part 2, C.3 – Industry Driven IT, page 2.

⁴⁰² Exhibit 20555-X0004, Appendix B – Part 2, C.3 – Industry Driven IT, Appendix A, pages 2-3.

⁴⁰³ Exhibit 20555-0038, Business case C.3, page 1.

06 Sampling Plans for the Inspection of Isolated Lots for Meters in Service (S-S-06) and with the AESO's Measurement System Standard (MSS).⁴⁰⁴

364. The need for the Industry Driven IT subprogram as part of the project assessment under capital tracker Criterion 1 was approved by the Commission in Decision 3218-D01-2015 for 2013, 2014, and 2015, based on projects identified by ATCO Electric in that proceeding.⁴⁰⁵ ATCO Electric provided an update to its business case originally filed in Proceeding 3218, as indicated below:

Table 30. Industry Driven IT project list and document index⁴⁰⁶

Project description	Document filed		Net capital additions (\$ million)					
			2014 approved ¹	2014 actual	2015 approved ¹	2015 updated	2016 forecast	2017 forecast
Annual Initiatives	Appendix B	C.3 Subprogram Update	0.8	0.8	0.8	0.8	0.8	0.8
Measurement Compliance	Appendix C.3.1	Project Update	3.2	1.1	1.9	6.8	4.0	--
TOTAL (subprogram)			4.0	1.9	2.7	7.6	4.8	0.8

¹ As originally filed in Proceeding 3218.

365. In Decision 3218-D01-2015, the Commission approved 2014 forecast capital additions for the Industry Driven IT subprogram in the amount of \$4.0 million.⁴⁰⁷ ATCO Electric's actual capital additions for this subprogram for 2014 were \$1.9 million, resulting in a negative variance of \$2.1 million.⁴⁰⁸ ATCO Electric explained that the negative variance is due to Measurement Compliance project work planned to be completed in 2014 being moved to 2015 due to the need for additional rule clarification.⁴⁰⁹

366. ATCO Electric forecast capital additions associated with the Industry Driven IT subprogram to be \$4.8 million in 2016 and \$0.8 million in 2017. Capital additions for the Industry Driven IT subprogram is primarily driven by the capital additions to the Measurement Compliance project of \$4.0 million for 2016.⁴¹⁰

367. Regarding the Annual Initiatives project, in a Commission IR, the Commission noted that although the actual 2014 expenditures for the Annual Initiatives project matched the forecast 2014 expenditures, two updates were not completed. In response to Commission IRs regarding the Annual Initiative project forecasts for 2014-2017 and the variance explanation of the 2014 forecast versus actual expenditures for the updates that were completed, ATCO Electric explained that the Annual Initiatives project forecasts are based on a five-year rolling average of historical spending for prior years excluding exceptions. ATCO Electric further explained that "Variance of actual cost to budget cannot be done at the individual project level" because

⁴⁰⁴ Exhibit 20555-X0004, Appendix B - Part 2, PDF pages 272, 279 and 282.

⁴⁰⁵ Decision 3218-D01-2015, paragraph 264.

⁴⁰⁶ Exhibit 20555-X0004, Appendix B - Part 2, C.3 - Industry Driven IT, page 2, Table 1.

⁴⁰⁷ Decision 3218-D01-2015, paragraph 262.

⁴⁰⁸ Exhibit 20555-X0004, Appendix B - Part 2, C.3 - Industry Driven IT, page 2.

⁴⁰⁹ Exhibit 20555-X0004, Appendix B - Part 2, Appendix C.3.1 Measurement Compliance, page 5.

⁴¹⁰ Exhibit 20555-X0004, Appendix B - Part 2, C.3 - Industry Driven IT, page 2, Table 1.

“Individual projects are not identified at the time of estimation and the budget is not a buildup of individual project estimates.”⁴¹¹

368. Regarding the Measurement Compliance project, ATCO Electric explained that the first phase of this compliance project was initiated in 2012. In the business case for the Industry Driven IT subprogram, originally filed in Proceeding 3218, ATCO Electric noted that the business case for the Measurement Compliance project consisted of phases 2, 3 and 4, with phase 4 forecast to be completed in 2015. The objective of phase 2 was to ensure compliance with S-S-06 to meet the January 1, 2014 timeline, and the objective of phases 2 to 4 was to minimize the risk associated with manual compliance assurance processes.⁴¹²

369. In the business case filed in Proceeding 3218, ATCO Electric provided the following table showing the 2013 actual and 2014-2015 forecast capital additions related to the Measurement Compliance project:

Table 31. 2013 to 2015 Measurement Compliance project capital additions⁴¹³

Capital additions	2013	2014	2015
	(\$000)		
Phase 2			
On-site testing rules	250	300	-
Field work management for on-site testing	250	310	-
Phase 3			
Meter group and sampling management	-	900	150
Meter equipment life cycle management	100	904	800
Meter testing results management	100	800	-
Phase 4			
Meter inventory management	-	-	500
Meter equipment performance monitoring	-	-	450
Total capital additions	700	3,214	1,900

370. ATCO Electric did not provide an update of this table in the current application.

371. While the Measurement Compliance project was originally forecast to be completed in 2015, in the project update, ATCO Electric submitted that work for the project scheduled in 2014 was moved to 2015, and the project would be completed in 2016. ATCO Electric explained that work originally estimated to be completed in 2014 was moved to 2015 because ATCO Electric determined during the detailed solution design phase that additional time and effort was required to address the complexity of translating the Measurement Canada rules to an operational level. ATCO Electric noted that the nature and driver for the Industry Driven IT group of projects in years 2016 and 2017 have not changed since its approval in Decision 3218-D01-2015 for 2013, 2014 and 2015.⁴¹⁴

⁴¹¹ Exhibit 20555-X0023, AE-AUC-2015JUL20-034 (a).

⁴¹² Exhibit 20555-0038, Business Case C.3, PDF pages 71 and 87.

⁴¹³ Exhibit 20555-0038, Business case C.3, Appendix B, page 6.

⁴¹⁴ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.3.1 Measurement Compliance, page 3.

372. Regarding the prudence of its actual 2014 capital additions for the Measurement Compliance project, ATCO Electric submitted that capital additions were reasonably and prudently incurred in the provision of safe and reliable electrical distribution service.⁴¹⁵

373. ATCO Electric provided a list of the 2016 deliverables in its project update:⁴¹⁶

Table 32. Updated 2016 Measurement Compliance project details

Planned deliverables (2016)	
Meter equipment life cycle management	• Tighten validation of meter life cycle events to ensure only eligible and compatible equipment can be used to minimize errors and address safety. • Track the in-stock & in-transit location of meters with more precision to eliminate inefficient and error prone manual processes which will ensure meters can be located for testing when required. • Implement remote devices that initiate transactions to enable automatic recording of meter events in ATCO-CIS. • Expand the automation of information flow between meter data gathering system (MV-90) and meter life cycle management system (ATCO-CIS) to eliminate manual processes and errors when metering is tested.
Meter testing result management	• Create a repository of meter equipment test results and test events information obtained from the test board application to enable the utilization of data for processing and improved auditability. • Create a repository of meter repair information and convert meter repair history from spreadsheets to enable the utilization of data for processing and improved auditability. • Expand the utilization of meter equipment repair & test results by interpreting the data and automate the update of equipment status to eliminate manual processes and minimize errors.

374. As shown in Table 31, for Phase 3, ATCO Electric originally forecast the total capital additions, from 2013 to 2015, for the meter equipment life cycle management deliverables and for the meter testing result management deliverables, to be \$1.8 million and \$0.9 million, respectively, for a total of \$2.7 million. The same planned deliverables are now forecast to cost a total of \$4.0 million, as illustrated by the 2016 forecast capital additions in Table 30 and the 2016 planned deliverables in Table 32.

375. In response to a Commission IR, ATCO Electric explained that the planned deliverables for 2016 are required for ATCO Electric to remain compliant with Measurement Canada standards related to S-S-06. In addition, ATCO Electric stated that measures must be taken that go beyond the sampling specification requirements needed to conform to S-S-06:

In particular, auditable records must be kept of the activities performed against each verified meter and made available for inspection to demonstrate compliance. The newly

⁴¹⁵ Exhibit 20555-X0004, Appendix B – Part 2, C.3 – Industry Driven IT, Appendix B, page 1.

⁴¹⁶ Exhibit 20555-X0004, Appendix B – Part 2, Appendix C.3.1 Measurement Compliance, page 6.

developed Electricity and Gas Inspection Act Inspection Regulations, Schedule 2, Part 1, Item 12 (references Act s. 16(2)) classifies failure to do so as a very serious violation with exposure to daily fines. ... Along with S-S-06, Measurement Canada provided an implementation plan with respect to the transition to new compliance sampling specifications where they advised stakeholders that they will be raising the level of monitoring activities with regard to compliance sampling inspection results and associated reporting requirements.⁴¹⁷

376. In a Commission IR response, ATCO Electric provided further evidence relating to how the requirements of S-S-06 are applicable to each of the 2016 deliverables, as identified in Table 32 above.⁴¹⁸

377. In the oral hearing, Commission counsel queried the ATCO Electric panel about the relationship between the planned deliverables for 2016 and the revisions to the S-S06 standard. Mr. Claude stated:

As of January 1st, 2014, requirements of S-S-06 will be applicable to all electromechanical meters, as well as electronic meters. And maybe I'll just add one more piece. As a result of that, we can no longer rely on our manual systems because of the increasing volume. We're increasing by in the neighbourhood of about 150 percent.

... So you'll find that a lot of these deliverables enable us to handle our meter fleet in a way such that we can be compliant with the rules and S-S-06.

... We've gotten to a spot where we now have our project estimates at a very tight stage where you'll see that we've listed 2015 and '16 at the definitive stage of the project.⁴¹⁹

378. Regarding the AESO's MSS, in response to a Commission IR requesting evidence that the planned deliverables for 2016 are required for ATCO Electric to remain compliant with the AESO's MSS, ATCO Electric stated that "AESO Measurement System Standards (section 6.3.3) requires that meters comply with the Act. AUC Rule 021 Settlement System Code (section 11.2) requires all system level meters to comply with the AESO Measurement System Standard."⁴²⁰

379. In the oral hearing, ATCO Electric was questioned by the CCA on the planned deliverables for 2016, and was asked to explain the difference between the practices and methods used today and those that will be used once the project is completed.⁴²¹ Mr. Claude submitted that changes are required to meet S-S-06 requirements:

... there are many different meters in our system, and when you're dealing with metering data, there's a very high volume of data that needs to be managed in order to meet the S-S-06 requirements. So in this particular case, talking about the validation of the lifecycle events, we're talking about many different aspects of that data within our metering databases.

⁴¹⁷ Exhibit 20555-X0023, AE-AUC-2015JUL20-036(a).

⁴¹⁸ Exhibit 20555-X0023, AE-AUC-2015JUL20-036(a).

⁴¹⁹ Transcript, Volume 3, page 444, lines 4-11; page 444, line 25 to page 445, line 2; page 446, lines 15-18.

⁴²⁰ Exhibit 20555-X0023, AE-AUC-2015JUL20-036(b).

⁴²¹ Transcript, Volume 1, page 128, line 9 to page 133, line 6.

I would say that we do. This, again, is in relation to being auditable back to the change of rules. So as the rules change, so do the processes and practices which results in changes as to how we provide and track that data to ensure it is auditable.

I believe we do -- have had bar codes, but I believe the change here is in result to how do we track all the different types of meters in relation to the rule.

In relation to the rule, as part of it, there's a whole bunch of additional information that needs to be tracked to ensure that we're in compliance with the rule.⁴²²

380. In its argument, ATCO Electric stated that the projects and additional functions identified in the Industry Driven IT subprogram are all required to meet the new Measurement Canada regulations, AESO or Commission requirements.⁴²³ ATCO Electric further explained that Measurement Canada does not require a specific reporting format, but S-S-06 does require reports to contain all pertinent information. ATCO Electric stated that while the Measurement Canada policy is not prescriptive in terms of how a company must achieve compliance, companies are expected and required to comply with the policy.⁴²⁴

381. Neither the UCA nor the CCA commented on the Industry Driven IT group of projects in their respective arguments and reply arguments.

Commission findings

382. In Decision 3218-D01-2015, the Commission approved the need for the Industry Driven IT subprogram for purposes of capital tracker treatment for 2013-2015. Further, the Commission determined the actual scope, level, timing and costs for the projects in 2013 to be prudent and the forecast scope, level, timing and costs for the projects for 2014 and 2015 to be reasonable. Therefore, the Commission has previously determined that these projects satisfied the project assessment requirement of Criterion 1.⁴²⁵

383. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project is not required, then there is no need to demonstrate that a project is needed in order to provide utility service at adequate levels, which constitutes the assessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that Industry Driven IT subprogram was not required in 2014.

384. With respect to the scope, level, timing and actual costs of the Industry Driven IT subprogram carried out in 2014, the Commission has reviewed ATCO Electric's 2014 actual capital additions of \$1.9 million associated with this subprogram, which is comprised of \$0.8 million related to the Annual Initiatives project and \$1.1 million related to the Measurement Compliance project, and finds that the scope, level, timing and the actual costs of \$0.8 million related to the Annual Initiatives project are generally consistent with the scope, level, timing and the actual costs of the work outlined in the business case for this project and approved in Decision 3218-D01-2015.

⁴²² Transcript, Volume 1, page 129, lines 5-12; page 129, line 25 to page 130, line 5; page 131, lines 6-9; page 131, line 23 to page 132, line 1.

⁴²³ Exhibit 20555-X0075, ATCO Electric argument, paragraph 114.

⁴²⁴ Exhibit 20555-X0075, ATCO Electric argument, paragraph 120.

⁴²⁵ Decision 3218-D01-2015, paragraph 264.

385. With respect to the scope, level, timing and actual costs of the Measurement Compliance project, the Commission notes that the 2014 actual capital additions of \$1.1 million for this project are considerably less than the approved 2014 forecast capital additions of \$3.2 million in Decision 3218-D01-2015. ATCO Electric explained in the application that the decrease in capital additions in 2014 for this group of projects was related to Measurement Compliance project work planned to be completed in 2014 being moved to 2015. With respect to the costs of the 2014 actual capital additions for this project, in light of the evidence supporting these costs and the evidence explaining the differences between approved forecast and actual costs, the Commission finds the actual costs to be prudent.

386. ATCO Electric requested capital tracker treatment for the Industry Driven IT subprogram in 2016 and 2017. As noted in Section 3, if a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the ongoing or recurring project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Industry Driven IT subprogram is not required to continue in 2016 or 2017. Neither the CCA nor the UCA objected to the need for this project in either 2016 or 2017.

387. With respect to the scope, level, timing and forecast costs of the Annual Initiatives projects of the Industry Driven IT subprogram for 2016 and 2017, the Commission has reviewed the business case and the relevant portions of the record for this project and finds the forecast scope, level and timing of the project for 2016-2017 to be reasonable. ATCO Electric's forecast capital additions associated with this project are \$0.8 million in each of 2016 and 2017. The Commission has reviewed the information supporting ATCO Electric's 2016 and 2017 forecasts and finds the total annual cost forecast to be reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision, based on a five-year rolling average of historical spending for prior years excluding exceptions.

388. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Annual Initiatives project are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

389. With respect to the Measurement Compliance project, the Commission accepts that this project is characterized as a third-party requirement, and that ATCO Electric is obligated to comply with Measurement Canada S-S-06 requirements and AESO MSS. However the Commission finds there is insufficient evidence on the record to demonstrate that the forecast cost increase for this project is reasonable as proposed for 2016.

390. ATCO Electric identified two sets of deliverables, the meter equipment lifecycle management project and the meter testing result management project, for 2016 with a total forecast cost of \$4.0 million.⁴²⁶ The Commission originally approved these deliverables to be

⁴²⁶ Exhibit 20555-X0004, Appendix B – Part 2, PDF pages 272 and 286.

completed during phase 3 of the Measurement Compliance project in 2013-2015 period at a cost approximately \$2.7 million, (\$0.2 million in 2013, \$1.7 million in 2014 and \$0.8 million in 2015), as shown in Table 31.⁴²⁷ While ATCO Electric explained that work was moved from 2014 to 2015 due to additional rule clarification effort, the Commission finds that ATCO Electric did not sufficiently explain the progress of work for this project, how the work delay in 2014 resulted in the need to move work into 2016, and why an additional \$4.0 million in 2016 was required to complete previously approved work.

391. Accordingly, without such evidence, the Commission is unable to determine if the Measurement Compliance project of the Industry Driven IT subprogram satisfies the requirements of Criterion 1. Therefore, the 2016 forecast capital costs of the Measurement Compliance project of the Industry Driven IT subprogram are denied capital tracker treatment at this time.

392. While the Commission is unable to make a finding with respect to capital tracker treatment for the forecast capital costs for 2016 associated with the Measurement Compliance project of the Industry Driven IT subprogram at this time, the Commission notes a company may apply for capital tracker treatment of capital expenditures after the capital additions are made. Consequently, ATCO Electric may reapply for capital tracker treatment of the capital costs associated with the Measurement Compliance project once it has incurred all the capital expenditures associated with this project. Any such application would require evidence supporting the need and justification for the prudence of the costs incurred for each planned deliverable for 2016 along with evidence that demonstrates it has employed the most cost effective option and considered all potentially reasonable alternatives in meeting compliance requirements of Measurement Canada S-S-06.

6.2.5 Tools and Instruments

393. The Tools and Instruments program is an annual recurring program and consists of the lifecycle replacement of existing tools and instruments that are at the end of their useful lives, and of the addition of new tools and instruments to address growth on ATCO Electric's system and to support new staff.⁴²⁸ The need for this program as part of project assessment under capital tracker Criterion 1 was approved in Decision 3218-D01-2015⁴²⁹ for 2013, 2014 and 2015. ATCO Electric provided an update to its business case, originally filed in Proceeding 3218, in Appendix B Part 2, Project Update D.1. The following table showing actual and forecast capital additions was provided in the update:

Table 33. 2010 to 2017 Tools and Instruments program historical actual and forecast costs⁴³⁰

	History					Forecast		
	2010	2011	2012	2013	2014	2015	2016	2017
	(\$ million)							
Forecast	0.9	2.5	1.5	1.5	2.4	2.5	2.6	2.7
Actual	2.0	3.7	4.4	2.1	2.7	-	-	-

⁴²⁷ Exhibit 20555-0038, Business Case C.3, Appendix B, page 6.

⁴²⁸ Exhibit 20555-X0007, application, paragraph 31, Table 3.2-1.

⁴²⁹ Decision 3218-D01-2015, paragraphs 301 and 304.

⁴³⁰ Exhibit 20555-X0004, Appendix B – Part 2, Project Update D.1, Appendix C, Table C-1.

394. The 2014 approved forecast capital additions for this program were \$2.4 million, while the actual 2014 capital additions were \$2.7 million, resulting in a \$0.3 million variance. ATCO Electric submitted that the variance from actual to forecast was 12.5 per cent, which was within the expected estimation accuracy of +/-30 per cent.⁴³¹

395. Regarding the prudence of its actual 2014 capital additions, ATCO Electric confirmed that the 2014 expenditures for this project were managed in accordance with its formal project management policies and procedures, as described in the application, and further submitted that the 2014 capital additions “were reasonably and prudently incurred in the provision of safe and reliable electrical distribution service.”⁴³²

396. The forecast capital additions for this program for 2016 and 2017 of \$2.6 million and \$2.7 million, respectively, were developed by applying inflation to the 2015 approved forecast.⁴³³ ATCO Electric clarified that the 2014 forecast, which was the basis for the 2015 approved forecast, was developed using a five-year aggregate average of historical expenditures, and explained the increased expenditures in 2011 and 2012 were the result of the need for additional tools and equipment due to a period of growth.⁴³⁴

397. ATCO Electric confirmed that the “need for the Tools and Instruments Program in years 2016 and 2017 has not changed since its approval in Proceeding 3218 for 2013 and 2014 and 2015.”⁴³⁵

398. The CCA recommended that the 2016 and 2017 forecast be held at the level of the 2012 and 2013 forecast of \$1.5 million, because the 2016 and 2017 forecast is based on a five year average that includes periods of higher growth than that expected in 2016 and 2017.⁴³⁶ In reply argument, ATCO Electric noted that the drivers of this program include asset replacement in addition to growth.⁴³⁷

Commission findings

399. In Decision 3218-D01-2015, the Commission approved the need for the Tools and Instruments program for purposes of capital tracker treatment for 2013-2015. Further, the Commission determined the actual scope, level, timing and costs for the program in 2013 to be prudent and the forecast scope, level, timing and costs for the program for 2014 and 2015 to be reasonable. Therefore, the Commission has previously determined that this program satisfied the project assessment requirement of Criterion 1.

400. With respect to the true-up of 2014 actual costs, as noted in Section 3, if there is no evidence on the record of the true-up proceeding demonstrating that a project was not required in 2014, then there is no need to demonstrate that a project was needed in order to provide utility service at adequate levels in 2014, as would otherwise be required under the project assessment component of Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that the Tools and Instrument program was not required in 2014.

⁴³¹ Exhibit 20555-X0004, Appendix B – Part 2, Project Update D.1, Appendix C, page 1.

⁴³² Exhibit 20555-X0004, Appendix B – Part 2, D. Tools and Instruments Program Preamble, page 2.

⁴³³ Transcript, Volume 3, page 456, lines 8-24.

⁴³⁴ Transcript, Volume 3, page 458, lines 10-16.

⁴³⁵ Exhibit 20555-X0004, Appendix B – Part 2, Project Update D.1, page 2.

⁴³⁶ Exhibit 20555-X0076, CCA argument, paragraphs 121-122.

⁴³⁷ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 97.

401. With respect to the scope, level and timing of this program carried out in 2014, the Commission has reviewed ATCO Electric's 2014 actual capital additions associated with this program and finds that they are generally consistent with the scope, level and timing of the work outlined in the business case for this capital tracker and approved by the Commission in Decision 3218-D01-2015. The Commission has also reviewed the costs of the 2014 actual capital additions for this program in light of the evidence supporting these costs, the associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, and finds the actual costs to be prudent.

402. In the present application, ATCO Electric also requested capital tracker treatment for this program on a forecast basis in 2016 and 2017. As noted in Section 3, where a project or program is part of an ongoing multi-year program, or if a project or program is of an annual recurring nature for which the need has been previously approved by the Commission for purposes of capital tracker treatment, in the absence of evidence that the project or program is no longer required, the Commission will not undertake a reassessment of need under Criterion 1. The Commission finds no evidence on the record of this proceeding to indicate that this program is not required to continue in 2016 or 2017.

403. With respect to the scope, level and timing of this program for 2016 and 2017, the Commission has reviewed the updated business case and the relevant portions of the record for this program and finds the forecast scope, level and timing of this program for 2016 and 2017 to be reasonable. ATCO Electric's forecast capital additions associated with the Tools and Instruments program are \$2.6 million in 2016 and \$2.7 million in 2017. For projects that are of an annual recurring nature, the Commission considers the forecast methodology of using a five-year aggregate average of historical expenditures and then applying an inflation factor to be a reasonable forecast method. While the five-year average includes periods of higher growth than that expected in 2016 and 2017, the Commission recognizes that the forecast includes asset replacement in addition to growth, as noted by ATCO Electric above. The Commission has reviewed the information supporting ATCO Electric's forecasts and finds the total annual cost forecasts, including the forecast methodology, to be reasonable.

404. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Tools and Instruments program are reasonable as proposed for 2016 and 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, the Commission finds that this programs satisfies the project assessment requirement of Criterion 1.

6.3 Assessment of new capital tracker programs

405. This section deals with ATCO Electric's projects or programs that have not been previously approved for capital tracker treatment. For such projects or programs, the Commission determined that, as part of project assessment, the applicant must demonstrate that a project proposed for capital tracker treatment is required to provide utility service at adequate levels, that the scope, level and timing of the project are reasonable, and that the costs of the project are reasonable for forecast projects and prudent for completed projects.⁴³⁸

⁴³⁸ Decision 2013-435, paragraph 278.

6.3.1 Distribution Automation

406. This annual recurring program consists of two main project categories: Field Supervisory Control And Data Acquisition (Field SCADA) and Control Room Technology Development and Integration (Control Centre). ATCO Electric provided a business case for the Distribution Automation program in Appendix B – Part 3 of the application.

407. The Field SCADA project consists of installing certain devices on ATCO Electric's distribution infrastructure and its primary purpose is to acquire data and provide remote control of switches to restore service to customers when power outages occur. The Control Centre project consists of the acquisition of a SCADA Master that serves to collect and present data in a control centre, software implementation for integration with existing systems, and further automation to support operational intelligence.⁴³⁹ ATCO Electric noted that the SCADA Master currently in use is shared with ATCO Electric Transmission.⁴⁴⁰ ATCO Electric indicated that these two projects combined will provide remote visibility and automated control of ATCO Electric's distribution system in the areas where the devices are installed⁴⁴¹ as, for example, ATCO Electric will be able to operate the distribution system remotely without the need for field personnel to travel long distances to manually operate a switch.⁴⁴²

408. ATCO Electric identified two alternatives to the proposed Distribution Automation program: (i) continuing to use the shared SCADA Master; and (ii) changing the rate of Field SCADA device installations. ATCO Electric explained that in order to leverage the benefits of distribution automation, integration with several distribution enterprise systems is required. ATCO Electric rejected the first alternative on the basis that the shared SCADA Master is subject to physical and cyber security regulations that prohibit integration with other systems, and the cost required to comply with the regulations would be greater than the cost required to implement a SCADA Master solely for the distribution function.⁴⁴³ ATCO Electric also dismissed the second alternative on the basis that there is a need for these projects at this time:

Each of the proposed field SCADA projects and Control Room Technology development projects are supported by authenticated engineering studies. All projects are required to ensure that ATCO Electric is able to provide adequate levels of service and public safety.⁴⁴⁴

409. ATCO Electric provided the historical and forecast capital additions for the Distribution Automation program in the program preamble and business case:⁴⁴⁵

⁴³⁹ Exhibit 20555- X0003, Appendix B - Part 3, L.1 – Distribution Automation, page 10.

⁴⁴⁰ Exhibit 20555- X0003, Appendix B - Part 3, L.1 – Distribution Automation, page 3.

⁴⁴¹ Exhibit 20555- X0003, Appendix B – Part 3, L.1 – Distribution Automation, page 2.

⁴⁴² Exhibit 20555- X0003, Appendix B – Part 3, L.1 – Distribution Automation, page 3.

⁴⁴³ Exhibit 20555- X0003, Appendix B – Part 3, L.1 – Distribution Automation, pages 3-4 and 12-13.

⁴⁴⁴ Exhibit 20555- X0003, Appendix B – Part 3, L.1 – Distribution Automation, page 13.

⁴⁴⁵ Exhibit 20555- X0003, Appendix B – Part 3, L. Distribution Automation Program Preamble and L.1 – Distribution Automation, page 6, Table 1, page 7, Table 2.

Table 34. 2010 to 2017 Distribution Automation program historical actual and forecast capital additions

	2010 actual	2011 actual	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast	2017 forecast
	(\$ million)							
Field SCADA				1.9	2.2	3.5	3.4	2.5
Control Centre				0.0	1.1	0.0	0.0	0.6
Total	1.5	0.6	0.3	1.9	3.3	3.5	3.4	3.1

410. ATCO Electric submitted that the Distribution Automation program is required to maintain safety and service reliability. ATCO Electric explained that due to the present size and complexity of its distribution system, it has become increasingly difficult to safely and effectively operate the system in the traditional manner, whereby PLTs manually perform switching to address power outages. As well, the addition of automated systems would reduce the risk of errors and outage response times.⁴⁴⁶

411. In relation to the Field SCADA project, ATCO Electric explained that the SCADA device installation locations were chosen based on engineering studies that consider areas of poor reliability, remoteness, public impact, and system complexity.⁴⁴⁷

412. ATCO Electric submitted that it identified and prioritized the locations for the Field SCADA project based on the following criteria: historical outage records, reliability statistics, travel time, ease of access, availability of loops and alternate feeds, expert consultation, the ratio of estimated customer-interruption hours that can be saved over estimated automation cost, and the location of critical customers, such as hospitals and airports.⁴⁴⁸ Using these criteria, ATCO Electric identified the following five cities and rural areas for the Field SCADA project:

- City improvements: Deployment of SCADA onto several prioritized feeders in major urban centers. In the spring/summer of each year, an engineering planning study will identify the feeders to target, along with a recommend scope, based on a methodology developed in a 2014 engineering study. Engineering will proceed throughout the year, with construction and commissioning to come in spring of the following year, and project completion by the end of that year. This will initially focus on Fort McMurray and Grande Prairie. The planned and completed city projects are:
 - 2013 – 2014: Fort McMurray Phase 1 (Downtown)
 - 2014 – 2015: Fort McMurray Phase 2 (Thickwood/Timberlea residential)
 - 2015 – 2016: Fort McMurray or Grande Prairie (Scope determined – 2015)
 - 2016 – 2017: Additional city project (Scope determined - 2016)
 - 2017 – 2018: Additional city project (Scope determined - 2017)
- Rural improvements: Deployment of SCADA on several rural feeders, targeting primarily critical customers such as hospitals, correctional centres, and airports, as well as nearby towns and larger communities that service these facilities. These were determined according to a methodology developed in an engineering study completed

⁴⁴⁶ Exhibit 20555- X0003, Appendix B – Part 3, L.1 – Distribution Automation, pages 2-3.

⁴⁴⁷ Exhibit 20555- X0003, Appendix B – Part 3, L.1 – Distribution Automation, page 3.

⁴⁴⁸ Exhibit 20555- X0023, AE-AUC-2015JUL20-061(b) and (d).

in 2014. Each year's rural priorities will be determined by subsequent studies using the same methodology and performed on an annual basis.⁴⁴⁹

413. During the hearing, Mr. Claude submitted that the Field SCADA project is of an annual and recurring nature, that ATCO Electric knows it will be doing the work in future years, and that the forecast is reasonable:

Q: But, sir, how would that not be the Commission effectively approving a bucket of money for each of those years, given that we haven't been given any specific project associated with the forecast?

A. MR. CLAUDE: This aspect of the program is very much an annual occurring type of program where on, an annual basis, we indicated that we've got roughly 366 feeders out there. By no means do we intend to automate them all, but there's certainly a large volume to work with.

We have a distribution automation organization that has been developing and working through standards over the last number of years, and we're delivering on Fort McMurray as we speak and moving through some of the different phases there. And we intend to similarly move forward at roughly the same rate and the same pace and go through the selected sites based on the criteria.

So we've put forward what we feel is a reasonable forecast for the field SCADA. I think we indicate a 30 percent level of accuracy, and because we have work planned in those years, and we know we'll be doing the work, we felt it would be prudent to put forward our best forecast for those years, and as we get into those years, we most certainly refine them.

But we feel we're right now positioned to be able to deliver on work similarly to what we've been able to do year to date, and based on the criteria and the selection criteria that we have in those practices, we've determined the areas that we'd like to focus in on.⁴⁵⁰

414. Mr. Claude, in an exchange with the Commission panel chair, further commented on the scope for the Field SCADA project, stating the following:

MR. CLAUDE: In terms of the specific scope, I think we haven't put that on there, because I think until we get a little deeper into the project, we wouldn't really have all the particulars, but at a very high level, most certainly we would, because these circuits in urban stress are existing as they are. We also have to ensure that we've got the resources to be able to deliver on them. And we've got the standards in place to be able to execute on them.

MR. CLAUDE: I think we would have a pretty good idea of what those circuits would be.

Q: But you don't know? There's no concrete business plan or project that says: Here's the circuits. This is what we're doing? That doesn't exist yet?

A. MR. CLAUDE: I think we would have a list of circuits based on this criteria. It's just not on the record, sir. I think that's probably where we're not necessarily able to show that.⁴⁵¹

⁴⁴⁹ Exhibit 20555- X0003, Appendix B – Part 3, L.1 – Distribution Automation, pages 9-10.

⁴⁵⁰ Transcript, Volume 3, page 551, line 14 to page 552, line 19 (Mr. Claude).

⁴⁵¹ Transcript, Volume 4, page 661, line 14 to page 662, line 4 (Mr. Claude).

415. The CCA and the UCA characterized the Distribution Automation program forecast as a “bucket of costs” and both recommended the program be denied for capital tracker treatment in 2016 and 2017.^{452 453} The CCA submitted that ATCO Electric did not have details to support its costs, other than a budget, a high level plan and a rough geographical location.⁴⁵⁴

416. ATCO Electric refuted the “bucket of costs” characterization, submitting that the program forecasts for 2016 and 2017 were “sufficiently well-defined.”⁴⁵⁵ ATCO Electric asserted that the Distribution Automation program is similar to its Small Projects Reliability Improvements project and its Third-Party Relocations program, where specific projects are not identified and forecast costs are based on historical expenditure levels.⁴⁵⁶

417. In reply argument, the UCA argued that the Third-Party Relocations program, in contrast to the Distribution Automation program, is driven by third-party requests, which are outside of the company’s control. Regarding the Small Projects Reliability Improvements project, the UCA was of the view that the “bucket of costs” methodology is justified for the Small Projects Reliability Improvements project, which is dependent on emerging system performance issues; unlike the Distribution Automation program, where factors are within the utility’s control.⁴⁵⁷

Commission findings

418. ATCO Electric described the Distribution Automation program as an annual recurring program made up of a number of smaller related projects which consist of installing equipment and devices in urban and rural areas, and the development of a distribution system control centre, to provide remote visibility and automated control of its distribution system. In its 2013 true-up and 2014-2015 capital tracker forecast applications, ATCO Electric did not request capital tracker treatment for this project in 2013 and 2014. ATCO Electric also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application. In the present application, ATCO Electric requested capital tracker treatment for the Distribution Automation program on a forecast basis in 2016 and 2017.

419. Regarding the need for the program, the Commission accepts ATCO Electric’s explanation of the shortcomings of continuing to operate in its current manner, which is labour and time-intensive:

MR. CLAUDE: ... our electrical system is typically reenergized through more of a manual effort. So if a switch is out, we would receive that information through customer calls that say: There's an outage in the area. We would be able to single that back to a location. We would then deploy a serviceman -- we've talked about PLTs over the last little while -- out to that location to figure out where the problem is. They may have to drive all kinds of lines, lengths of line to sort out where this in order to get that customer back on or to minimize the number of customers that are affected.

Distribution SCADA gives you the ability to have a remote device in the field and that can, not only gather data, but in time, will be able to actually -- we'll be able to actually -- we'll be able to use that device to control the device as well to be able to reduce the

⁴⁵² Exhibit 20555-X0076, CCA argument, paragraphs 125 and 127.

⁴⁵³ Exhibit 20555-X0074, UCA argument, paragraphs 4b and 23.

⁴⁵⁴ Exhibit 20555-X0076, CCA argument, paragraph 125.

⁴⁵⁵ Exhibit 20555-X0075, ATCO Electric argument, paragraph 186.

⁴⁵⁶ Exhibit 20555-X0075, ATCO Electric argument, paragraph 186.

⁴⁵⁷ Exhibit 20555-X0082, UCA reply argument, paragraphs 30-35.

number of customers impacted and isolate the fault to get the customers back on as quickly as possible.

...

MR. CLAUDE: The big difference between the two is today all we can do is gather that data, and we have information on assets. Once we have a distribution and SCADA master of our own, it gives us the ability to take that information and physically visualize it on a map connected to those enterprise systems, such as GIS.⁴⁵⁸

420. The Commission also relies on Mr. Claude's submission that ATCO Electric's system has become increasingly complex and difficult to operate safely and effectively without distribution automation.

421. Accordingly, the Commission accepts ATCO Electric's evidence that its distribution system cannot be effectively operated in the traditional manner, due to the system's growing size and complexity, and that the Distribution Automation program is required to maintain safety and service reliability in some areas.

422. Regarding the CCA's and the UCA's concern that the Distribution Automation program forecast scope and costs are not adequately supported by detailed plans and geographical locations, the Commission agrees and finds that ATCO Electric did not provide sufficient evidence to show that the scope, level, timing and costs of the Distribution Automation program are reasonable.

423. Regarding the scope, level, timing and costs for a dedicated Control Centre, the Commission finds that ATCO Electric did not provide sufficient evidence to quantify the scope and cost of continuing with the SCADA Master that is shared with the transmission function, nor did it provide any details of when a transition to a dedicated Control Centre would be required.

424. ATCO Electric identified two alternatives to the proposed Distribution Automation program: (i) continued use of the transmission SCADA Master; and (ii) changes to the rate of Field SCADA device installation. Although ATCO Electric provided a compelling reason to dismiss the first alternative, it neither described the scope, nor quantified the costs that would be required to satisfy the physical and cyber security regulations, which would have assisted the Commission and other parties in making an assessment of the comparable benefit and value of a dedicated distribution control centre, as compared to the continued use of the shared SCADA Master. Regarding the second alternative, ATCO Electric failed to demonstrate how a slower rate of Field SCADA device installation would adversely affect service quality or safety.

425. Both the CCA and the UCA characterized the Distribution Automation program forecast as a "bucket of costs."⁴⁵⁹ Given that the location and details of the Field SCADA projects for 2015 to 2017 were not well established, the Commission agrees with the interveners' characterization of the program forecast, and does not accept ATCO Electric's argument that the forecast was "sufficiently well-defined."⁴⁶⁰

⁴⁵⁸ Transcript, Volume 3, page 526, line 14 to page 528, line 21 (Mr. Claude).

⁴⁵⁹ Exhibit 20555-X0076, CCA argument, paragraph 125 and Exhibit 20555-X0074, UCA argument, paragraph 4b

⁴⁶⁰ Exhibit 20555-X0075, ATCO Electric argument, paragraph 186.

426. In light of the above considerations, the Commission finds that the evidence provided by ATCO Electric does not support a finding that the scope, level, timing and costs for the Distribution Automation program are reasonable as proposed for 2016 and 2017. Accordingly, the Commission finds that the Distribution Automation program does not satisfy the project assessment requirement of Criterion 1, and is denied capital tracker treatment at this time.

427. Regarding the need to justify the prudence of capital expenditures for the years in which capital tracker treatment was not applied for, the Commission observes that the K factor revenue requirement calculation for the Distribution Automation program proposed for 2016 and 2017 incorporates the 2013 and 2014 actual and 2015 forecast capital additions for this program, that were incurred, or forecast to be incurred, under the I-X mechanism prior to requesting capital tracker treatment. The Commission stated at paragraph 48 of Decision 2013-435, that a company may apply for capital tracker treatment of capital expenditures after the capital additions are made. In light of the Commission's determination that the evidence provided by ATCO Electric does not support a finding that the scope, level, timing and costs for the Distribution Automation program are reasonable as proposed for 2016 and 2017, if ATCO Electric applies for capital tracker treatment for this program on a true-up basis for 2016 and 2017, any such application would require evidence supporting the scope, level and timing of the program and the prudence of the actual costs incurred from 2013 to 2015, as well as 2016 to 2017.

6.3.2 Transmission Driven

428. The Transmission Driven program is an annually occurring program composed of a number of smaller related projects driven by ATCO Electric Transmission, and may consist of relocating, extending or reconfiguring distribution lines to accommodate relocated substations, and the purchase of transmission line assets where distribution circuits are under strung on decommissioned transmission lines. ATCO Electric maintained that the projects are externally driven by Transmission Facilities Owners and the AESO. ATCO Electric provided a business case and an engineering study for each project in the Transmission Driven program in Appendix B-Part 4 of the application.⁴⁶¹

429. ATCO Electric only applied for capital tracker treatment of this project for 2017 on a forecast basis. ATCO Electric provided the following table showing its historical actual capital additions and forecast capital additions associated with the Transmission Driven program.

Table 35. 2010 to 2017 Transmission Driven program capital additions⁴⁶²

	2010	2011	2012	2013	2014	2015 approved ⁵	2015 update	2016	2017
	(\$ million)								
Forecast	1.6	4.1	7.5	--	--	--	5.9	11.1	4.8
Actual	1.3	1.5	1.3	0.7	4.1	--	--	--	--

⁵ As originally filed in Proceeding 3218.

⁴⁶¹ Exhibit 20555-X0002, Appendix B – Part 4.

⁴⁶² Exhibit 20555-X0002, Appendix B– Part 4, Table 1, page 2.

430. ATCO Electric also provided the following list of projects in the Transmission Driven program and their associated capital additions:

Table 36. 2013 to 2017 Transmission Driven program projects capital additions⁴⁶³

Project description	Net capital additions						
	2013 actual	2014 approved ⁵	2014 actual	2015 approved ⁵	2015 update	2016 forecast	2017 forecast
	(\$ million)						
O.1 – 6L91 Asset Acquisition	-	-	-	-	1.3	-	-
O.2 – 6L68 Asset Acquisition	-	-	-	-	2.4	-	-
O.3 – 6L79 Asset Acquisition	-	-	-	-	-	4.1	-
O.4 – 6L82 Asset Acquisition	0.1	-	-	-	-	5.2	-
O.5 – Double Circuit Mitigation	0.6	-	0.1	-	0.8	1.8	3.2
O.6 – Central East Region Transmission Driven Work	(0.4)	-	0.2	-	-	-	-
O.7 – Jasper Interconnection	-	-	-	-	-	--	1.6
O.8 – 6L06 Asset Acquisition	0.1	-	0.9	-	0.7	-	-
O.9 – 6L31 Asset Acquisition	-	-	2.2	-	-	-	-
O.10 – 6L22/6L44 Asset Acquisition	-	-	0.2	-	0.3	-	-
O.11 – High Prairie Area Transmission Driven Work	-	-	0.1	-	0.4	-	-
O.12 – Hanna Area Transmission Driven Work	0.2	-	0.3	-	-	-	-
TOTAL	0.7	-	4.1	-	5.9	11.1	4.8

⁵ As originally filed in Proceeding 3218.

431. ATCO Electric submitted that its 2013 and 2014 expenditures were managed in accordance with the formal project management policies, methodologies and practices provided in its application, which describes capital project delivery including management of scope, schedule, cost, risk, procurement, and process. ATCO Electric submitted that the 2013 and 2014 capital additions were reasonably and prudently incurred in the provision of safe and reliable electrical distribution service.⁴⁶⁴

432. ATCO Electric provided business cases for all projects listed above. Projects with capital additions in 2016 and 2017, the subject of this application, are described further below.

433. ATCO Electric explained that the acquisition of transmission line 6L79 and 6L82 is required because its distribution lines share poles with transmission lines which are proposed to be decommissioned as part of the Central East Transmission Development (“CETD”) plan. These projects consist of the purchase of transmission poles and lines, the relocation, conversion or retirement of assets, and the construction of other facilities as required to maintain service,⁴⁶⁵ to ensure continuous electricity service to distribution customers. The purchase price for the assets to be acquired from ATCO Electric Transmission is based on the assets’ net book value.⁴⁶⁶ ATCO Electric maintained that not proceeding with the 6L79 and 6L82 projects could have

⁴⁶³ Exhibit 20555-X0002, Appendix B – Part 4, Table 13, page 2.

⁴⁶⁴ Exhibit 20555-X0002, Appendix B – Part 4 page 3.

⁴⁶⁵ Exhibit 20555-X0002, Appendix B– Part 4, Business Case 0.3, page 2 and Business Case 0.4, page 3.

⁴⁶⁶ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.3, page 3 and Business Case 0.4, page 3.

several large scale impacts, including delaying the completion of the approved CETD plan and requiring a costly rebuild of the facilities necessary to serve existing customers.⁴⁶⁷ ATCO Electric described several alternatives to the 6L79 and 6L82 projects but rejected these alternatives on the basis that either the costs would be too high relative to the recommended project plans or the alternatives would not provide needed contingency scenarios compared to the recommended project plans.⁴⁶⁸

434. ATCO Electric described the Double Circuit Mitigation project as a continuation of a multi-year project to mitigate the potential for contacts between distribution and transmission lines on the same structure resulting in outages and equipment damage. ATCO Electric explained that over time, the top transmission circuit sags, resulting in a greater frequency of contacts with the bottom distribution circuit. ATCO Electric explained that while double circuits have served well over the last 30 to 40 years by saving on construction costs, today the increased power running through the transmission lines has necessitated upgrades and improvements to allow safe and reliable operation of these transmission lines well into the future.⁴⁶⁹ ATCO Electric noted that without remediation, the probability of future double circuit conflict is very high and will likely increase due to continued load and generation growth. ATCO Electric also described the risks to power system reliability and integrity as very high, as cascading line outages can result in widespread area outages. ATCO Electric noted that the identification and prioritization processes is set by ATCO Electric Transmission and the AESO.⁴⁷⁰ ATCO Electric indicated that it assesses viable alternatives on a location by location basis as part of the project management process. The alternatives may include relocation of one of the circuits or increasing pole height.⁴⁷¹

435. ATCO Electric described the Jasper Interconnection project as related to a new substation, Sheridan 2085S, which is an AESO project. ATCO Electric will be required to relocate and reconnect its existing distribution lines to this new substation to maintain service to existing distribution customers.⁴⁷² ATCO Electric explained that the evaluation of transmission alternatives in the Jasper Interconnection project is ongoing with the AESO and ATCO Electric Transmission, and includes evaluation of the new substation location. The proposed distribution project assumes that the facilities recommended in the ATCO Electric Transmission's business case⁴⁷³ will proceed. ATCO Electric notes that any changes from the proposed to the approved transmission solution are likely to result in higher distribution costs.⁴⁷⁴

436. Neither the UCA nor the CCA commented on the Transmission Driven program in their respective arguments and reply arguments.

Commission findings

437. In its 2013 true-up and 2014-2015 capital tracker forecast applications, ATCO Electric did not request capital tracker treatment for this project in 2013 and 2014. ATCO Electric also did not request capital tracker treatment for this project in 2014 on an actual basis in the present

⁴⁶⁷ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.3, page 5 and Business Case 0.4, page 5.

⁴⁶⁸ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.3, page 5 and Business Case 0.4, page 5.

⁴⁶⁹ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.5, pages 2-3.

⁴⁷⁰ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.5, pages 3-4.

⁴⁷¹ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.5, page 6.

⁴⁷² Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.7, page 2.

⁴⁷³ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.7, Appendix D.

⁴⁷⁴ Exhibit 20555-X0002, Appendix B – Part 4, Business Case 0.7, page 4.

application. In the present application, ATCO Electric requested capital tracker treatment for the Transmission Driven program on a forecast basis in 2017.

438. The Commission has reviewed the business cases and engineering studies provided by ATCO Electric and the evidence on the record of this proceeding with respect to the Transmission Driven program and finds that the information provided by ATCO Electric supports a finding that the project is required during 2017 to maintain service reliability and safety at adequate levels.

439. With respect to the scope, level and timing of this program for 2017, the Commission has reviewed the business cases and the relevant portions of the record for this program and finds the forecast scope, level and timing of the program for 2017 to be reasonable. ATCO Electric's forecast capital additions associated with this program are \$4.8 million in 2017. The Commission has reviewed the information supporting ATCO Electric's 2017 forecasts and finds the total annual cost forecasts to be reasonable based on the detailed project information and alternative analysis provided in the business cases and engineering studies.

440. The Commission observes that the K factor revenue requirement calculation for the Transmission Driven program proposed for 2017 incorporates the 2013 and 2014 actual and 2015 to 2016 forecast capital additions for this program, which were incurred or are forecast to be incurred under the I-X mechanism prior to requesting capital tracker treatment. As set out in Section 3 of in this decision, in the absence of any evidence that the 2013 to 2016 capital additions incurred, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2017 forecast costs.

441. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Transmission Driven program are reasonable as proposed for 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this program satisfies the program assessment requirement of Criterion 1.

6.3.3 Underground Rebuilds, Replacements and Life Extension

442. This ongoing program involves the annual work required to extend the life of underground line components and the replacement of equipment that is deteriorated, damaged, and defective as determined by failures and test results. ATCO Electric explained that failures of underground cables and equipment can lead to lengthy service interruptions and the repairs can take a significant amount of time, particularly in the winter months due to their locations underground. Accordingly, ATCO Electric carries out two types of work under this ongoing, annual program: cable replacement and life extension and work related to the equipment on underground distribution systems.⁴⁷⁵ ATCO Electric provided a business case including its internal engineering guidelines for the Underground Rebuilds, Replacements and Life Extension program in Appendix B – Part 4 of the application.

443. The cable replacement and life extension component of the program consists of testing and inspecting the underground cable to assess whether the cable is at the end of its life. If

⁴⁷⁵ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, pages 2-3.

possible, ATCO Electric extends the life of the existing cable by injecting remediation fluids along the cable to repair the insulation, before considering replacement. All primary voltage cable installed prior to 1985, as well as newer cables in areas with high faults, are tested to determine whether they can remain in service and, if not, they are assessed to determine if they are eligible to undergo the life extension process or if they require replacement. ATCO Electric explained that cable life extension is a cost-effective solution and is primarily conducted on high voltage cables, as low voltage cables are unsuitable for the life extension process. In order to successfully extend the life of the underground cable, ATCO Electric may be required to dig up buried cable splices and replace them in order to allow the remediation liquid to flow properly.⁴⁷⁶ However, if a particular section of cable includes three or more splices then that cable will be replaced unless it is cost-effective to dig up and replace the splices.⁴⁷⁷

444. Regarding the work related to the equipment on underground distribution systems, ATCO Electric inspects pad mounted transformers, switching cubicles, and pedestals. Based on the condition of those assets, they may be replaced prior to failure if they are leaking oil, exhibit corrosion or have mechanical damage. The underground distribution system equipment is also replaced upon failure.⁴⁷⁸ For both the cable replacement and life extension, and the underground distribution system equipment components of this program, ATCO Electric explained that the age of the assets is not a criterion for replacement. In an IR response, ATCO Electric further indicated that while age is not determinative of whether cable is replaced, it does play an important role in selecting cable for testing:

Cable manufactured after technology advances in the 1980's such as cross-linked polyethylene insulation, tree-retardant chemical additions to the insulation material, encapsulated neutrals, solid conductors and super-clean construction methods has led to fewer problems with water-treeing and breakdown of the insulation in newer cable.

The breakdown of insulation leads to cable failures. Cable injection mitigates these issues. Older cable that is successfully injected and performs well can be left in the ground for an indefinite period of time.

For these reasons, cable is put through the testing and life extension process if the cable was installed prior to 1985.⁴⁷⁹

445. ATCO Electric is currently only seeking capital tracker treatment for this project for 2017 on a forecast basis. ATCO Electric provided the following table that shows its historical actual capital expenditures and 2015 to 2017 forecast capital expenditures associated with the Underground Rebuilds, Replacements and Life Extension program:

⁴⁷⁶ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, pages 3-5.

⁴⁷⁷ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix E, page 6.

⁴⁷⁸ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, page 4.

⁴⁷⁹ Exhibit 20555-X0023, AE-AUC-2015JUL20-070.

Table 37. 2012 to 2017 Underground Rebuilds, Replacements and Life Extension program capital expenditures⁴⁸⁰

Program component	Actual			Forecast		
	2012	2013	2014	2015	2016	2017
	(\$ million)					
Transformers and Equipment	3.4	2.6	2.1	2.8	2.9	3.0
Cable Replacement	2.1	0.6	2.9	1.1	1.7	1.7
Life Extension (Cable Injections)	1.3	0.9	1.2	1.0	1.0	1.1
Total expenditures	6.8	4.1	6.2	4.9	5.6	5.8

446. ATCO Electric further provided capital expenditure breakdowns by program component in support of its forecast costs. Table 38 shows the transformers and equipment replacement unit costs and forecast number of units to be replaced.

Table 38. 2012 to 2017 Underground transformer and equipment replacement units and costs⁴⁸¹

Description	2012 actual	2013 actual	2014 actual	2015 forecast	2016 forecast	2017 forecast
Underground transformers						
# of units replaced	70	44	51	55	55	55
Average unit cost (\$)	22,398	24,502	32,749	27,800	28,567	29,564
Total expenditures (\$ million)	1.6	1.1	1.7	1.5	1.6	1.6
Underground Equipment						
# of units replaced	10	7	3	7	7	7
Average unit cost (\$)	186,219	215,587	143,561	191,517	196,803	203,671
Total expenditures (\$ million)	1.9	1.5	0.4	1.3	1.3	1.4

447. The forecast number of transformer and equipment replacements are based on the three year average of replacements from 2012 to 2014 and similarly, the forecast costs are based on the three year average of actual costs from 2012 to 2014, escalated for 2015, 2016, and 2017.⁴⁸²

448. For the life extension component of the program, ATCO Electric provided historical and forecast amounts of cable with successful life extension, the life extension success rate, and the unit costs and total costs.

⁴⁸⁰ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix C, table C-1, page 1.

⁴⁸¹ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix E, tables E-1 and E-2, page 1.

⁴⁸² Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix E, page 1.

Table 39. Underground cable life extension results and costs⁴⁸³

	1	2	3	4	5	6	7
Year	Cable program (metres)	New cable and solid strand (metres)	Successful life extension (metres)	Success rate	Unsuccessful life extension (metres)	Life extension unit cost (\$/metres)	Life extension total cost (\$ million)
2017 forecast	21,601	1,607	16,237	81%	3,757	66.6	1.1
2016 forecast	21,601	1,607	16,237	81%	3,757	64.4	1.0
2015 forecast	21,601	1,607	16,237	81%	3,757	62.7	1.0
2014	27,924	3,220	17,424	71%	7,280	71.2	1.2
2013	20,772	1,395	18,567	96%	810	49.0	0.9
2012	32,848	10,371	16,999	76%	5,478	74.3	1.3
2011	16,107	206	12,289	77%	3,612	57.3	0.7
2010	12,825	563	9,470	77%	2,792	74.3	0.7
2009	15,516	343	8,558	56%	6,615	85.6	0.7
Prior	8,877	257	6,945	81%	1,675	-	-
Total to 2014	134,869	16,355	90,252	76.15%	28,262		

449. ATCO Electric explained that 2014 costs for cable life extension were higher than in previous years given the additional work required to upgrade transformer foundations and terminations, and higher test failure results. The forecasts in columns 1, 2 and 4 were based on three year averages of the corresponding amounts for the years 2011, 2013 and 2014. ATCO Electric excluded 2012, given its higher test population, as shown in column 1. Furthermore, the unit costs for cable life extension were based on the three year average of unit costs for 2011, 2013 and 2014, escalated for 2015, 2016 and 2017.⁴⁸⁴

450. ATCO Electric also provided a table outlining the underground cables with unsuccessful life extensions that subsequently required replacement.

⁴⁸³ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix D, table D-1, page 1.

⁴⁸⁴ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix D, page 3.

Table 40. Underground cable unable to be life extended⁴⁸⁵

	1	2	3	4	5	6	7	8
Year	Start of year cable balance (metres)	Program failed cable (metres)	Program replaced cable (metres)	Year-end balance (metres)	Emergency and secondary cable replacement (metres)	Total cable replaced (metres)	Total cost (\$ million)	Unit cost of replacement (\$/metre)
2017 forecast	19,492	3,757	1,653	21,596	1,500	3,153	1.7	552.8
2016 forecast	17,389	3,757	1,653	19,492	1,500	3,153	1.7	534.2
2015 forecast	15,285	3,757	1,653	17,389	500	2,153	1.1	519.8
2014	13,554	7,280	5,549	15,285	1,220	6,769	2.9	423.8
2013	13,332	810	588	13,554	810	1,398	0.6	439.5
2012	10,954	5,478	3,100	13,332	544	3,644	2.1	567.7
2011	7,834	3,612	492	10,954	2,819	3,311	1.4	433.5
2010	6,477	2,792	1,435	7,834	2,125	3,560	1.9	536.9
2009	1,675	6,615	1,813	6,477	4,426	6,239	3.3	531.7
Prior	0	1,675	0	1,675	0	0	-	-

451. ATCO Electric explained that the 2014 unit cost was lower than the forecast years' costs because in 2014 crews were able to better coordinate replacement work with the testing and life extension activities, as opposed to having the design and construction for replacements proceed separately, which is typically the case due to the requirement for access permissions and project design timelines. To forecast the metres of cable replacement (column 3) in 2015, 2016 and 2017, ATCO Electric multiplied the program failed cable amount for those years by 44 per cent. The emergency replacements were then added to the forecast amounts in column 3 to arrive at the total cable replaced forecast (column 6).⁴⁸⁶ The 44 per cent is an historically derived number based on cables with unsuccessful life extensions that required replacement within a few years. Specifically, Mr. Howell explained that "that's just a recognition of the fact that historically we haven't proceeded to replacement with all the cables just because we couldn't apply the life -- the treatment to extend their life. And that historical ratio is at 44 percent, and that's what we applied going forward."⁴⁸⁷

452. ATCO Electric indicated that the replacement unit costs were based on a three year average of 2011 to 2013 actual unit costs escalated for 2015, 2016 and 2017. ATCO Electric noted that 2014 was excluded from the historical average calculation given "the lower than normal unit cost of cable replaced (which is not expected to be repeated in the forecast years ..."⁴⁸⁸

453. During the hearing, Mr. Howell explained that when ATCO Electric escalated its historical costs for the 2015, 2016 and 2017 forecasts, it takes "the past years and we looked at

⁴⁸⁵ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix D, table D-2, page 2.

⁴⁸⁶ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix D, page 3.

⁴⁸⁷ Transcript, Volume 3, page 562, lines 8-13 (Mr. Howell).

⁴⁸⁸ Exhibit 20555-X0002, Appendix B – Part 4, Business Case P.1, Appendix D, page 3.

the expenditure by category, and we applied contractor inflation to the contractor charges and company labour inflation to the company labour charges and the other to the other charges.”⁴⁸⁹

Commission findings

454. In its 2013 true-up and 2014-2015 capital tracker forecast applications, ATCO Electric did not request capital tracker treatment for this project in 2013 and 2014. ATCO Electric also did not request capital tracker treatment for this project in 2014 on an actual basis in the present application. In the present application, ATCO Electric requested capital tracker treatment for the Underground Rebuilds, Replacements and Life Extension program on a forecast basis in 2017.

455. The Commission has reviewed the business case and engineering guidelines provided by ATCO Electric and the evidence on the record of this proceeding with respect to ATCO Electric’s Underground Rebuilds, Replacements and Life Extension program and finds that the information provided by ATCO Electric supports a finding that the project is required during 2017 to maintain service reliability and safety at adequate levels.

456. With respect to the scope, level and timing of this program for 2017, the Commission has reviewed the business case and the relevant portions of the record for this program and finds the forecast scope, level and timing of the program for 2017 to be reasonable. ATCO Electric’s forecast capital additions associated with this program are \$5.8 million in 2017. The Commission observes that the 2017 forecast costs for this program are generally consistent with the variance explanations provided in the business case for the actual expenditures over the most recent five-year period. The Commission has reviewed the information supporting ATCO Electric’s 2017 forecasts and finds the total annual cost forecasts to be reasonable based on its forecasts using historical averages, as well as the historical life extension success rates and cable replacement failures.

457. The Commission observes that the K factor revenue requirement calculation for the Underground Rebuilds, Replacements and Life Extension program proposed for 2017 incorporates the 2013 to 2014 actual and 2015 to 2016 forecast capital additions for this program that were incurred, or forecast to be incurred, under the I-X mechanism prior to requesting capital tracker treatment. As set out in Section 3 of this decision, in the absence of any evidence that the 2013 to 2016 capital additions for this project incurred, or forecast to be incurred, under I-X were not reasonable, the Commission accepts them for purposes of the second component of the accounting test and in assessing the reasonableness of the 2017 forecast costs.

458. Given the above, the Commission finds that the information provided by ATCO Electric supports a finding that the scope, level, timing and forecast costs for the Underground Rebuilds, Replacements and Life Extension program are reasonable as proposed for 2017, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision. Accordingly, subject to these adjustments and directions, the Commission finds that this project satisfies the project assessment requirement of Criterion 1.

⁴⁸⁹ Transcript, Volume 3, page 571, lines 6-10 (Mr. Howell).

7 Accounting test under Criterion 1 – The project must be outside of the normal course of the company’s ongoing operations and Commission conclusion on Criterion 1

7.1 Accounting test for the 2014 true-up and 2016-2017 forecast

459. As explained in Decision 2013-435, the purpose of the accounting test is to determine whether a project or program (depending on the approved level of grouping) proposed for capital tracker treatment is outside the normal course of the company’s ongoing operations. This is achieved by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program.⁴⁹⁰

460. In Decision 2013-435, the Commission determined that the accounting test should be based on a “project net cost approach,” which is sufficient to satisfy the Commission that all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company’s ongoing operations, as required to satisfy Criterion 1. Under this approach, the extent to which a project is underfunded by the I-X mechanism is calculated by comparing the forecast or actual revenue requirement for that project to the going-in revenue historically associated with a similar type of capital expenditure escalated by I-X and including the effect on revenue of any changes in billing determinants.⁴⁹¹ The effect on revenue of any changes in billing determinants, which is calculated as the forecast percentage change in billing determinants in any given PBR year, was referred to as “Q”⁴⁹² or “Q factor.”

461. As set out in Section 4.4 of Decision 2013-435, the accounting test, as it relates to revenue calculations, consists of two components. The first component is the revenue provided under the I-X mechanism for a project or program proposed for capital tracker treatment. As explained in Decision 3434-D01-2015, this component of the accounting test utilizes the WACC rate embedded in a company’s approved going-in rates⁴⁹³ and requires assumptions regarding the values for the I-X index and Q for each year.

462. The second component is the revenue requirement calculations based on the forecast or actual capital additions for that project or program for a given PBR year, approved by the Commission as part of the project assessment review under Criterion 1. As set out in Decision 3434-D01-2015, for purposes of the revenue requirement calculations, this component of the accounting test requires assumptions regarding the current year’s WACC rate, namely, cost of debt, approved return on equity (ROE) and capital structure, including preferred shares.⁴⁹⁴

463. ATCO Electric’s calculation of the accounting test model for the 2014 capital tracker true-up and 2016 and 2017 capital tracker forecast was provided in Appendix A to the application, and subsequently updated in response to IR AE-AUC-2015JUL20-010(a).⁴⁹⁵

⁴⁹⁰ Decision 2013-435, paragraphs 149-150.

⁴⁹¹ Decision 2013-435, paragraphs 262-263.

⁴⁹² Decision 2013-435, paragraph 499.

⁴⁹³ Decision 3434-D01-2015, paragraph 37.

⁴⁹⁴ Decision 3434-D01-2015, paragraph 40.

⁴⁹⁵ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a), Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules).

464. In Decision 3218-D01-2015, the Commission established that the accounting test for a capital tracker true-up application for a given year should utilize the approved I-X index and the Q factor based on the final approved forecast of billing determinants for that year.⁴⁹⁶ For the 2014 capital tracker true-up, ATCO Electric used the 2014 I-X index of 1.59 per cent approved in Decision 2013-461.⁴⁹⁷ The 2014 Q factor of 3.58 per cent was based on ATCO Electric's forecast billing determinants, approved in the same Decision 2013-461.⁴⁹⁸

465. In Decision 3218-D01-2015, the Commission also acknowledged that for purposes of a capital tracker forecast, a company may be required to estimate the I factor and Q factor for the coming year.⁴⁹⁹ In the accounting test for 2016 and 2017, ATCO Electric used an I-X index value of 1.49 per cent for both years,⁵⁰⁰ which is equal to the 2015 I-X index value approved in Decision 2014-354.⁵⁰¹ ATCO Electric's 2016 and 2017 Q factors of 0.51 per cent and 1.57 per cent, respectively, were calculated using the percentage changes in revenues between succeeding years, based on 2012 approved final rates applied against the forecasts of billing determinants for 2016 and 2017.⁵⁰²

466. Regarding the WACC rate, for purposes of the 2014 capital tracker true-up and the 2016-2017 capital tracker forecast, ATCO Electric used the WACC rate of 7.05 per cent embedded in its going-in rates in the first component of the accounting test.

467. For the second component of the accounting test, for the 2014 true-up, ATCO Electric used the actual 2014 WACC rate of 6.39 per cent,⁵⁰³ based on the actual weighted average cost of debt (WACD) of 5.21 per cent, the approved equity thickness of 38 per cent and the approved ROE of 8.3 per cent,⁵⁰⁴ as determined in Decision 2191-D01-2015.⁵⁰⁵ For the purposes of the 2016 and 2017 capital tracker forecasts, ATCO Electric used a WACC rate of 6.23 per cent⁵⁰⁶ and 6.17 per cent,⁵⁰⁷ respectively. ATCO Electric noted that it had forecast debt issuances for 2016 and 2017 based on the rate that resulted from the company's most recent debt issuance in 2014.⁵⁰⁸

468. Another factor of the revenue requirement calculation in the second component of the accounting test is income tax. In Decision 3218-D01-2015, the Commission stated the following:

482. In reviewing ATCO Electric's income tax calculations, which were provided as a single hard-coded number for each capital project or program in the accounting test spreadsheet in ATCO Electric's initial application, the Commission considers that the level of disclosure initially provided by ATCO Electric was not helpful to the Commission and interveners in understanding the mechanics of ATCO Electric's income

⁴⁹⁶ Decision 3218-D01-2015, paragraph 461.

⁴⁹⁷ Decision 2013-461, paragraph 55.

⁴⁹⁸ Exhibit 20555-X0007, application, paragraph 192.

⁴⁹⁹ Decision 3218-D01-2015, paragraph 460.

⁵⁰⁰ Exhibit 20555-X0007, application, paragraphs 190-191.

⁵⁰¹ Decision 2014-354, paragraph 21.

⁵⁰² Exhibit 20555-X0007, application, paragraphs 226-227.

⁵⁰³ Exhibit 20555-X0022, Schedule 1-1, row 35, column AC.

⁵⁰⁴ Exhibit 20555-X0007, application, Appendix H.

⁵⁰⁵ Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.

⁵⁰⁶ Exhibit 20555-X0022, Schedule 1-1, row 35, column AQ.

⁵⁰⁷ Exhibit 20555-X0022, Schedule 1-1, row 35, column BC.

⁵⁰⁸ Exhibit 20555-X0007, application, paragraph 193.

tax calculations. ... the Commission considers that it is necessary for the company to disclose its assumptions and allocations in order for the Commission and interveners to be able to assess whether those assumptions and allocations are reasonable. Accordingly, in future capital tracker applications, ATCO Electric is directed to provide a breakdown of its capital tracker income tax calculations into their component parts (return, interest, depreciation, capital costs allowance, capitalized pension, ES&G and removal and abandonment costs). In addition, in future capital tracker applications, ATCO Electric is directed to provide supporting calculations for any income tax components that were assigned to capital projects or programs using an allocation methodology, and provide an explanation of how the total amounts to be allocated were calculated.⁵⁰⁹

469. In the application, ATCO Electric provided supporting calculations and a breakdown of the income tax calculations in its accounting model schedules.⁵¹⁰ To allocate capital cost allowance, ATCO Electric stated that it used the Alternative Methodology, which was the methodology used in Proceeding 20369, its 2013-2015 capital tracker compliance filing.⁵¹¹

470. The CCA submitted that ATCO Electric should recalculate the K factor to include the impact of the following deductions: capital cost allowance; allowance for funds used during construction (AFUDC); debt issue costs; engineering supervision & general (ES&G); reserve for injuries and damages claims; capital repair costs; right of way costs; removal and abandonment costs; and capitalized pension contributions.⁵¹² The CCA submitted that the testimony of Mr. McNabb on behalf of ATCO Electric confirmed that income tax deductions have an effect on the K factor.⁵¹³

Q. And, similarly, do capital trackers influence the amount of the company's capital cost allowance?

A. MR. MCNABB: So, again, to the extent you build capital, it will go to a UCC pool, and you'll take CCA on it.

Q. And that's whether it's tracked or not tracked?

A. MR. MCNABB: That's correct.

471. In response to an IR from the CCA, ATCO Electric gave reasons why it has not included AFUDC and debt issue costs deductions in its capital tracker tax calculation. ATCO Electric explained that because "AFUDC has not been included in the capital tracker revenue requirement (e.g. net earnings before tax), it would be inappropriate to then include it as a deduction for tax purposes in the capital tracker calculation." Regarding debt issue costs, ATCO Electric submitted that "issue costs are immaterial in nature, not directly attributable to capital tracker programs and have already been incorporated in 2012 going-in customer rates." In the same IR, ATCO Electric confirmed that ES&G, reserve for injuries and damages claims, capital repair costs, right of way costs, removal and abandonment costs, and capitalized pension contributions are included in the actual and forecast capital additions and submitted that it

⁵⁰⁹ Decision 3218-D01-2015, paragraph 482.

⁵¹⁰ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a) Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules), schedules 6-2 to 6-4, 7-2 to 7-4, 8-2 to 8-4 and 9-2 to 9-4.

⁵¹¹ Exhibit 20555-X0007, application, paragraph 215.

⁵¹² Exhibit 20555-X0076, CCA argument, paragraphs 98-117.

⁵¹³ Exhibit 20555-X0076, CCA argument, paragraph 101.

calculated the income tax component of the K factor consistent with the Commission-approved tax treatment of these costs.⁵¹⁴

472. ATCO Electric rejected the CCA's recommendations on the basis that the CCA's issue with ATCO Electric's tax calculation in the accounting test was previously tested in Proceeding 3218 and no new evidence has been submitted to justify a change in the determinations made by the Commission at paragraphs 482, 484 and 485 of Decision 3218-D01-2015.⁵¹⁵

482. ... Accordingly, in future capital tracker application, ATCO Electric is directed to provide a breakdown of its capital tracker income tax calculations into their component parts (return, interest, depreciation, **capital costs allowance, capitalized pension, ES&G and removal and abandonment costs**)....[emphasis added by ATCO Electric]

...

484. Subject to the above direction with respect to the breakdown of income tax calculations, the Commission generally accepts ATCO Electric's approach of isolating the income tax included in the capital tracker accounting test to those income tax items that are directly attributable to capital additions included as part of a capital tracker

485. ... **Accordingly, the Commission will not require ATCO Electric to include any additional income tax deductions**, nor will the Commission require the creation of an additional income tax-related deferral account. [emphasis added by ATCO Electric]
[footnotes removed]

473. No party raised issues with ATCO Electric's I-X and Q factor values, nor with the WACC rate of 7.05 per cent used in the first component of its accounting test. In addition, no party raised issues with the 2014 actual WACC rate of 6.39 per cent used in the second component of the accounting test for 2014. Similarly, Q factors and the ROE and capital structure components of the WACC forecast for 2016 and 2017 were not challenged by any party. However, in reply argument, the CCA stated that it was unable to verify that the approved equity thickness of 38 per cent and the approved ROE of 8.3 per cent were used to determine the K factor for ATCO Electric's capital tracker programs that had not been previously applied for, and surmised that ATCO Electric may not have used the correct values in the accounting test model.⁵¹⁶ Also, as discussed in Section 7.2, the CCA brought forward some issues with respect to the forecast cost of debt component of the 2016 and 2017 WACC rates.

Commission findings

474. In Decision 3218-D01-2015, the Commission expressed a concern with ATCO Electric's accounting test spreadsheets:

531. ... the Commission is concerned about errors that resulted from hard-coded numbers in ATCO Electric's accounting test spreadsheets. Without the opportunity to review the spreadsheet calculations made by a company in the spreadsheets it uses to support its regulatory applications, it is difficult for the Commission or interveners to verify the accuracy of the numbers used by the company. Regardless of the outcome of Proceeding

⁵¹⁴ Exhibit 20555-X0019, AE-CCA-2015JUL20-012.

⁵¹⁵ Exhibit 20555-X0080, ATCO Electric reply argument, paragraphs 92-95.

⁵¹⁶ Exhibit 20555-X0081, CCA reply argument, paragraph 60.

3558, in future applications, the Commission considers that ATCO Electric should reduce its reliance upon hard-coded numbers in its spreadsheets ...⁵¹⁷

Generally, the formulas in the accounting test spreadsheets provided by ATCO Electric in the application were linked and working.

475. Regarding the CCA's concern with the WACC value used in the K factor calculation for new capital tracker programs, the Commission observes that for all capital projects or programs, ATCO Electric provided linked spreadsheets showing the formula for the revenue requirement calculation that includes a WACC rate based on the approved equity thickness and ROE, and the mid-year rate base for the year(s) in which capital tracker treatment is being applied for. Accordingly, the Commission rejects the CCA's supposition that the calculations for the new capital tracker programs may require revision.

476. The Commission has reviewed ATCO Electric's schedules that make up its accounting test analysis for the purposes of the 2014 capital tracker true-up and the 2016 and 2017 capital tracker forecasts and finds these schedules to be reasonable and generally consistent with the accounting test methodology approved in Decision 2013-435. The Commission has also assessed the reasonableness of ATCO Electric's WACC, I-X and Q factor assumptions used in the first component of the accounting test, and WACC assumptions and income tax allocation calculations in the second component of the accounting test, for each of 2014, 2016 and 2017. The Commission's findings are set out below.

477. The Commission has verified that for the first component of the accounting test, ATCO Electric used the correct WACC rate of 7.05 per cent, embedded in its approved 2012 going-in rates, as required by Decision 3434-D01-2015. The Commission has verified also that for the 2014 true-up, ATCO Electric used the correct values for the I-X index and Q factor, as approved in Decision 2013-461.

478. When the application was filed, ATCO Electric did not have approved values for either the I-X index or Q factor for 2016 or 2017. Therefore, it used the I-X index value that was approved for its 2015 PBR annual rate adjustment filing, equal to 1.49 per cent for both 2016 and 2017.⁵¹⁸ ATCO Electric's 2016 and 2017 Q factors of 0.51 per cent and 1.57 per cent, respectively, were based on 2012 approved final rates applied against the forecasts of billing determinants for 2016 and 2017.⁵¹⁹

479. ATCO Electric proposed in its application that the forecast values of the I and Q factors will be trued up to approved numbers as part of the 2016 and 2017 capital tracker true-up applications.⁵²⁰ However, regarding the 2016 forecast, the Commission observes that, since the filing of the application, the 2016 I-X index of 0.90 per cent and billing determinants forecast were approved in Decision 20822-D01-2015. To minimize future true-ups, the Commission directs ATCO Electric, in its compliance filing to this decision, to use the approved 2016 I-X index value and the Q factor based on the forecast billing determinants approved in Decision 20822-D01-2015 for purposes of its 2016 capital tracker forecast accounting test. For the

⁵¹⁷ Decision 3218-D01-2015, paragraph 531.

⁵¹⁸ Exhibit 20555-X0007, application, paragraph 191.

⁵¹⁹ Exhibit 20555-X0007, application, paragraphs 226-227.

⁵²⁰ Exhibit 20555-X0007, application, paragraphs 191-192.

purpose of this decision, the Commission considers ATCO Electric's forecast I and Q values for 2017 to be reasonable.

480. As discussed earlier in this section, in Decision 3434-D01-2015, the Commission determined that revenue requirement calculations in the second component of the accounting test should be based on the current year's WACC rate, which, in turn, is calculated based on the actual or forecast cost of debt, as well as the approved ROE and capital structure for that year.⁵²¹ With the exception of the forecast debt cost component of WACC discussed in Section 7.2, no party raised concerns with ATCO Electric's calculations of either the 2014 actual or 2016 and 2017 forecast WACC rates.

481. In Section 7.2 below, the Commission finds ATCO Electric's 2014 actual WACC of 5.21 per cent to be reasonable for purposes of the accounting test. The Commission also finds ATCO Electric's forecast WACC rates of 4.98 per cent and 4.88 per cent for 2016 and 2017, respectively, reflecting the 2014 actual debt rate, to be reasonable for purposes of the accounting test, subject to a true-up.

482. Therefore, the Commission finds ATCO Electric's 2014 actual WACC rate of 6.39 per cent used in the second component of its accounting test, based on the 2014 actual WACC of 5.21 per cent, as well as the approved equity thickness of 38 per cent and the approved ROE of 8.3 per cent from Decision 2191-D01-2015, to be reasonable. The Commission also finds ATCO Electric's forecast WACC rates of 6.23 per cent and 6.17 per cent for 2016 and 2017, respectively, to be reasonable. In future capital tracker true-up applications for 2016 and 2017, these forecast WACC rates will be trueed up to the actual cost of debt and the approved ROE and capital structure for 2016 and 2017, which will be determined in a future generic cost of capital (GCOC) proceeding.

483. In Decision 3218-D01-2015, the Commission gave directions to ATCO Electric regarding the level of detail in its income tax allocation calculations that is required to assist the Commission and interveners to understand the inputs and methods used.⁵²² In this application, ATCO Electric provided a breakdown of its capital tracker income tax calculations into their component parts (return, interest, depreciation, capital cost allowance, capitalized pension, ES&G and removal costs). In addition, ATCO Electric provided supporting calculations for any income tax components that were assigned to capital projects or programs using the Alternative Methodology. In the same decision, the Commission also found that ATCO Electric's approach was acceptable, stating:

484. ... the Commission generally accepts ATCO Electric's approach of isolating the income tax included in the capital tracker accounting test to those income tax items that are directly attributable to capital additions included as part of a capital tracker. The Commission is aware that this may result in the company collecting more income tax-related revenue requirement through the capital tracker mechanism than the company actually paid to the Canada Revenue Agency. However, this situation would arise as a result of deductions and additions for tax purposes that are not related to capital additions.

⁵²¹ Decision 3434-D01-2015, paragraph 40.

⁵²² Decision 3218-D01-2015, paragraph 482.

484. The Commission is satisfied with the income tax calculations provided by ATCO Electric in its accounting test model and continues to find ATCO Electric's approach acceptable, and considers that the CCA did not provide any new evidence to support its conclusion that ATCO Electric should recalculate the K factor to include the impact of several income tax deductions. Accordingly, the Commission will not require ATCO Electric to recalculate the K factor to include the impact of these income tax deductions.

485. For the reasons above, the Commission is satisfied that ATCO Electric's accounting test model sufficiently demonstrates that all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company's ongoing operations, as required to satisfy the accounting test component of Criterion 1. The Commission's determinations on whether ATCO Electric's projects or programs proposed for capital tracker treatment in 2014 on an actual basis and in 2016 and 2017 on a forecast basis satisfy both the accounting test and the project assessment components of Criterion 1, are set out in Section 7.3.

7.2 2014 actual and 2016-2017 forecast debt rates used in the accounting test

486. As set out in Section 7.1, consistent with the directions in Decision 3434-D01-2015, ATCO Electric used in the second component of its accounting test for the 2014 true-up, the actual 2014 WACC rate of 6.39 per cent, based on the 2014 actual WACD of 5.21 per cent, and the approved equity thickness of 38 per cent and ROE of 8.3 per cent from Decision 2191-D01-2015. The 2014 WACD of 5.21 per cent is a blend of ATCO Electric's new \$248.8 million long-term debt issue in 2014 with the coupon rate of 4.085 per cent, and rates for 19 prior debt issues dating back to 1999, as set out in ATCO Electric's 2014 Rule 005⁵²³ filing.⁵²⁴

487. For the purposes of the 2016 and 2017 capital tracker forecast, ATCO Electric used the rate that resulted from its most recent debt issuance in 2014 to calculate the forecast WACC rates of 6.23 per cent and 6.17 per cent for 2016 and 2017, respectively.⁵²⁵

488. In its argument, ATCO Electric confirmed that the assumptions used in forecasting the WACC for the 2016 to 2017 period is consistent with the assumptions approved by the Commission in Decision 3434-D01-2015.⁵²⁶ The Commission stated the following in paragraph 77 of that decision:

77. The debt forecasts to be used in the second component of the accounting test for 2016 and 2017 should be based on the best information that is known by the companies at the time they make their forecasts, meaning that they should include the impacts of their most recent actual debt and preferred share issuances in developing their forecasts, along with all outstanding historical debt and preferred share issuances, but the companies are not required to forecast the movement of interest rates in the future. For example, if a company knows it will need to issue debt in a forecast year it may forecast the rate for that future debt issuance based on the rate that resulted from the company's most recent debt issuance. The Commission also notes that the cost of debt and preferred shares will ultimately be trued-up to actuals, as discussed further in Section 3.3.

⁵²³ Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

⁵²⁴ Exhibit 20555-X0007, application, Appendix H.

⁵²⁵ Exhibit 20555-X0007, application, paragraph 193 and Appendix H.

⁵²⁶ Exhibit 20555-X0075, ATCO Electric argument, paragraph 223.

489. In response to a CCA IR inquiring how ATCO Electric secures debt, and whether it hedges foreign currency risk or uses interest rate future contracts, ATCO Electric explained that its financing is obtained through its parent company, CU Inc. (a wholly owned subsidiary of Canadian Utilities Limited) for “more optimal sizing of public financings” and to “minimize the costs of market access.” ATCO Electric was of the view that forward curve contracting for debt is speculative because the timing and amount of future capital requirements are subject to change. ATCO Electric explained that it would consider hedging foreign currency risk in the purchase of goods or services priced in currency other than Canadian dollars.⁵²⁷

490. The CCA argued that CU’s historically passive approach of relying on its size to get a good rate may have been reasonable in the past decades of falling interest rates; however, the CCA indicated that rates are forecast to rise and that, in a rising rate environment, such a passive approach may not secure the lowest rate, based on the best information available.⁵²⁸ Additionally, the CCA refuted ATCO Electric’s reasons for dismissing interest rate future contracts, submitting that since ATCO Electric issues debt periodically and not daily, it is required to forecast its capital requirements regardless. Regarding the timing issue, the CCA submitted that ATCO Electric likely could not prove that its exiting method offers a better opportunity for perfect timing.⁵²⁹ The CCA viewed that the reasons to hedge foreign currency, i.e., to protect against a change in exchange rate, should similarly apply to interest rates.⁵³⁰

491. The CCA observed that the use of forward curve rates as a basis for forecasting was an issue discussed in EPCOR Transmission’s 2015-2017 GTA, Proceeding 3539, and the Commission accepted the rate as a reasonable indicator of interest rates during EPCOR Transmission 2015-2017 GTA test period.⁵³¹

492. The CCA expressed its view that because debt costs are recovered from customers, ATCO Electric should be explicitly required to justify the prudence of its debt issuance.⁵³² The CCA suggested that the prudence test occur on a go-forward basis at the next capital tracker true-up proceeding, and clarified its recommendation as follows:

... the test will include a consideration of the forward curve rates available at the time of this proceeding for debt issued at the time when AEL actually issues debt. These rates would be compared to the debt rate which AEL actually incurred in order to determine, in part, whether AEL acted prudently.⁵³³

493. Noting paragraph 77 of Decision 3434-D01-2015, the CCA further clarified:

To be clear, the CCA is not proposing any change to the Decision. The CCA is not proposing that AEL change its forecast or its accounting test. The CCA is only recommending that the Commission take into account, at true-up, the forward curve rates that could have been locked in as compared to the actual rates at which debt was issued at. This would be in the same manner in which the Commission assesses prudence when evaluating foreign currency exposure or when a project is forecast to cost \$G and it

⁵²⁷ Exhibit 20555-X0019, AE-CCA-2015JUL20-005(a)-(c).

⁵²⁸ Exhibit 20555-X0076, CCA argument, paragraph 57.

⁵²⁹ Exhibit 20555-X0076, CCA argument, paragraphs 62-63.

⁵³⁰ Exhibit 20555-X0076, CCA argument, paragraph 70.

⁵³¹ Exhibit 20555-X0076, CCA argument, paragraph 58.

⁵³² Exhibit 20555-X0076, CCA argument, paragraph 73.

⁵³³ Exhibit 20555-X0076, CCA argument, paragraph 78.

comes in at \$H. In all cases, the variance is identified and the company is expected to support the prudence of its actions. So for example, if AEL issues debt at significantly higher rates than the current forward curve rate at which it can lock in a debt rate today for issuance in the future, then AEL should have to justify why its actions were prudent. ...⁵³⁴

494. In its reply argument, ATCO Electric refuted the CCA's characterization that CU Inc. takes a "passive approach" to securing debt, stating that CU Inc.'s "practice is to continually monitor the debt capital markets for opportunities to satisfy the long-term debt needs for the benefit of customers."⁵³⁵

495. ATCO Electric did not agree with the CCA's view that a foreign currency hedge is equivalent to an interest rate hedge. During the hearing, Mr. McNabb clarified the difference:

A. MR. MCNABB: ... When we do enter into a foreign currency hedge, we're committed to a transaction. There's a purchase order raised. We know the exact amount. It's a purchase order, as a form of a legal document. Whereas, if you entered into trying to do some sort of interest rate hedge or something along those lines now, you don't know the exact dollars you're going to need by the -- trying to lock into something now when you aren't firmly committed to the dollars, that's why it's speculative. It may look like the hedge, but actually, it's quite the opposite. It's very speculative.⁵³⁶

496. To further its argument, ATCO Electric pointed out that its policy with respect to foreign currency exposure is that it hedges this exposure at the time it executes a contract for the goods or services, and therefore it knows the precise amount of currency required, and the timing of the amount is current, rather than at some time in the future.⁵³⁷

497. Additionally, ATCO Electric submitted that it risks a finding of imprudence regardless of its actions:

If the actual cost of financing that ATCO Electric obtains is higher than some prior forward curve price, there is no doubt that the CCA will take the position that ATCO Electric was imprudent. However, if ATCO Electric were to lock in the underlying Government of Canada bond yield for a future financing based on some forward curve price, and the cost of financing when actually completed in the future could have been lower, there is little doubt that the CCA again would take the position that ATCO Electric was imprudent.⁵³⁸

Commission findings

498. The CCA's argument, as it relates to ATCO Electric's forecast cost of the debt component of its WACC, brings forward two issues: (i) whether ATCO Electric's forecast WACD of 4.98 per cent and 4.88 per cent, based on its actual 2014 WACD for 2016 and 2017, respectively, is reasonable; and (ii) whether the Commission should use a forward curve debt rate in its assessment of the prudence of the incurred, actual cost of debt.

⁵³⁴ Exhibit 20555-X0076, CCA argument, paragraph 73.

⁵³⁵ Exhibit 20555-X0080, ATCO reply argument, paragraph 80.

⁵³⁶ Transcript, Volume 1, page 162, lines 6-18 (Mr. McNabb).

⁵³⁷ Exhibit 20555-X0080, ATCO reply argument, paragraph 81.

⁵³⁸ Exhibit 20555-X0080, ATCO reply argument, paragraph 84.

499. Regarding the first issue, the Commission considers that ATCO Electric's debt forecast methodology, which uses the WACD rate reflecting the company's most recent debt issuance as a forecast rate for future debt issuances, is consistent with the method approved at paragraph 77 of Decision 3434-D01-2015, referenced earlier in this section. In its argument, the CCA clarified that it "is not proposing that AEL change its forecast or its accounting test. The CCA is only recommending that the Commission take into account, at true-up, the forward curve rates that could have been locked in as compared to the actual rates at which debt was issued at."⁵³⁹

500. The Commission recognizes that in Decision 3539-D01-2015⁵⁴⁰ dealing with EPCOR Transmission's 2015-2017 GTA, the Commission accepted the forward curve as a reasonable indicator of interest rates during the test period and directed EPCOR Transmission to reflect a forecast cost of debt for 2016 based on the 2016 forward curve cost of debt.⁵⁴¹ However, the Commission is cognizant of the differences in purpose between this decision and Decision 3539-D01-2015. The purpose of Decision 3539-D01-2015 was to set rates for EPCOR Transmission on a forecast basis, whereas the purpose of this decision is to establish forecast capital tracker amounts as part of a PBR plan for ATCO Electric. Unlike the approved revenue requirement for EPCOR Transmission, the 2016 and 2017 capital tracker forecasts approved in this application are subject to a full true-up proceeding (including cost of debt). In light of these differences, the Commission continues to consider that the debt forecasting methodology approved at paragraph 77 of Decision 3434-D01-2015 should continue to be used in ATCO Electric capital tracker proceedings.

501. On the second issue, the CCA proposed to use the forward curve rates in considering the prudence of the incurred, actual debt rate. However, the CCA did not raise any issues, nor did it provide any evidence on the available forward curve rates to assess the prudence of ATCO Electric's 2014 actual cost of debt. Rather, the CCA indicated that its proposal would be utilized to consider the prudence of the debt issuance in future capital tracker true-ups. The Commission notes that the onus remains on the company to demonstrate that its actual debt costs, included in the capital tracker true-up accounting test for each year, are reasonable.

502. In Decision 20522-D02-2016,⁵⁴² dealing with AltaGas Utilities Inc.'s 2014 capital tracker true-up and 2016-2017 capital tracker forecast application, the Commission made the following determination regarding the review process to establish the reasonableness of a company's actual debt costs included in the capital tracker true-up accounting test:

329. At paragraph 89 of Decision 3434-D01-2015, the Commission determined that "... the embedded debt rate used in the second component of the accounting test in the true-up process should match the rate that appears on the company's Rule 005 filing from the associated year, and if it does not match, the Commission directs the company to provide an explanation of why it does not match, in its capital tracker true-up application." Therefore, the Commission will accept, in the absence of any evidence that the actual incurred cost of debt was not reasonable, the company's embedded debt rate that appears on the company's Rule 005 filing from the associated year for purposes of

⁵³⁹ Exhibit 20555-X0076, CCA argument, paragraph 73.

⁵⁴⁰ Decision 3539-D01-2015: EPCOR Distribution & Transmission Inc., 2015-2017 Transmission Facility Owner Tariff, Proceeding 3539, Application 1611027-1, October 21, 2015.

⁵⁴¹ Decision 3539-D01-2015, paragraphs 836-838.

⁵⁴² Decision 20522-D02-2016: AltaGas Utilities Inc., 2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast Application, Proceeding 20522, January 21, 2016.

the second component of the accounting test in the capital tracker true-up process. This approach recognizes the PBR incentives provided in Decision 2012-237, which allow companies to manage their businesses during the PBR term, to be followed by a prudence review upon re-basing or in a future rate application. Accordingly, the prudence of the debt rates reported in the company's Rule 005 filing during the PBR term will be included in the prudence review at the time of rebasing for purposes of establishing the going-in rates on a go-forward basis for the next generation PBR plan or in a general rate application.⁵⁴³

503. ATCO Electric's actual 2014 WACD of 5.21 per cent as reported in its Rule 005 filing, is a blend of ATCO Electric's new \$248.8 million long-term debt issue in 2014 with the coupon rate of 4.085 per cent, and rates for 19 prior debt issues dating back to 1999. No issues were raised regarding the reasonableness of the 2014 debt issuance in this proceeding. Accordingly, consistent with paragraph 329 of Decision 20522-D02-2016 referenced above, and based on the evidence filed in this proceeding, the Commission finds ATCO Electric's 2014 actual WACD of 5.21 per cent to be reasonable for purposes of the second component of the accounting test in the 2014 true-up process. The prudence of this actual debt will be assessed at the time of rebasing for purposes of establishing the going-in rates on a go-forward basis for the next generation PBR plan or in a GTA.

504. Earlier in this section, the Commission indicated that ATCO Electric's debt forecast methodology, which uses the WACD rate reflecting the company's most recent debt issuance as a forecast rate for future debt issuances, is consistent with the method approved in paragraph 77 of Decision 3434-D01-2015, which the Commission found preferable for capital tracker application purposes. Given the Commission's approval of the actual WACD rate of 5.21 per cent for 2014, the Commission also finds ATCO Electric's forecast WACD of 4.98 per cent and 4.88 per cent, based on its actual cost of debt in 2014, for 2016 and 2017, respectively, to be reasonable for purposes of the accounting test. In future capital tracker true-up applications for 2016 and 2017, this forecast WACD will be trued up to the actual cost of debt for 2016 and 2017, as approved by the Commission.

7.3 Commission's conclusions on Criterion 1

505. In Section 6 of this decision, based on the project assessment under Criterion 1, the Commission approved the need, scope, level and timing for most projects or programs that ATCO Electric proposed for capital tracker treatment either on an actual basis for 2014 or on a forecast basis for 2016 or 2017, with the exception of the Fort McMurray North Service Building project, the Measurement Compliance and MDM System Upgrade projects, and the Distribution Automation project. The Commission also generally confirmed the prudence of actual capital additions for the true-up of each of the capital tracker projects or programs in 2014. As well, with the exception of the above noted projects, the Commission determined that ATCO Electric's forecast capital expenditures for the proposed 2016 and 2017 capital tracker projects are generally reasonable, subject to the adjustments and Commission directions applicable to all projects and programs set out in Section 6.1.1.1 of this decision.

506. Because the adjustments required pursuant to Section 6.1.1.1 of this decision affect the forecast 2016 or 2017 costs for all projects or programs, the Commission cannot make a determination in this decision as to whether any of ATCO Electric's projects or programs

⁵⁴³ Decision 20522-D02-2016, paragraph 329.

proposed for capital tracker treatment in 2016 and 2017 on a forecast basis, satisfy the project assessment requirement of Criterion 1.

507. In Section 7.1 of this decision, the Commission found the form of ATCO Electric's accounting test model to be reasonable and generally consistent with the accounting test methodology approved in Decision 2013-435. However, the Commission directed some changes with respect to ATCO Electric's accounting test assumptions related to the I-X index and Q factor values for 2016.

508. Accordingly, although the Commission finds the general form of ATCO Electric's accounting test model to be reasonable and consistent with the methodology approved in Decision 2013-435, the Commission cannot make a determination in this decision as to whether any of ATCO Electric's projects or programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis satisfies the accounting test requirement of Criterion 1 and, accordingly, whether any of ATCO Electric's projects or programs satisfy Criterion 1 in its entirety.

509. The Commission directs ATCO Electric, in its compliance filing to this decision, to revise its accounting test for 2016 and 2017, based on approved final forecast or actual capital additions, the 2016 model assumptions and other directions as set out in this decision. ATCO Electric is further directed to provide a summary table in the compliance filing to this decision, showing for each capital tracker project or program, a comparison of the 2016 and 2017 forecast capital additions applied for in this proceeding and the 2016 and 2017 forecast capital additions, revised in accordance with the directions set out in this decision.

8 Criterion 2 – Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

510. With respect to Criterion 2, the Commission clarified in Decision 2013-435 that in addition to asset replacement projects and projects required by an external party, in principle, a growth-related project will satisfy the requirements of Criterion 2 where it can be demonstrated that customer contributions, together with incremental revenues allocated to the project on some reasonable basis, when added to the revenue provided under the I-X mechanism, are insufficient to offset the revenue requirement associated with the project in a PBR year.⁵⁴⁴ Certain projects for capital tracker treatment that do not fall into any of the growth-related, asset replacement or external party related categories might also satisfy Criterion 2 in certain circumstances as discussed in Section 3.2.4 of Decision 2013-435.⁵⁴⁵

511. As set out in Section 3 of this decision, for the purposes of the true-up of the 2014 capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in Decision 3218-D01-2015, there is also no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program has changed. In its application ATCO Electric confirmed that "all project or program drivers for previously approved trackers have not changed."⁵⁴⁶ Therefore, ATCO Electric did not provide any additional evidence on how the projects or programs included in the 2014 capital tracker true-up satisfy the requirements of Criterion 2.

⁵⁴⁴ Decision 2013-435, paragraph 309.

⁵⁴⁵ Decision 2013-435, paragraph 314.

⁵⁴⁶ Exhibit 20555-X0007, application, paragraph 24.

512. For 2016 and 2017 capital tracker programs that were previously approved by the Commission for capital tracker treatment in Decision 3218-D02-2015, ATCO Electric submitted “the drivers for these approved capital tracker programs have not changed and as such a reassessment under Criterion 2 is not needed.”⁵⁴⁷ ATCO Electric provided information in support of how the new programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis satisfy the requirements of Criterion 2. Table 41 below provides a summary of ATCO Electric’s evidence with respect to Criterion 2 in support of the 2016 and 2017 capital tracker forecasts.

Table 41. Applied-for 2016-2017 capital tracker projects or programs and Criterion 2 requirements

Project name	Criterion 2 project type
Previously approved programs ⁵⁴⁸	
Distribution to Transmission Contributions	Third-party driven
Buildings, Structures & Leasehold Improvements	Growth
Information Technology Related	Third-party driven/asset replacement or refurbishment/growth
Tools and Instruments	Asset replacement or refurbishment/growth
Transportation Equipment	Asset replacement or refurbishment/growth
Third-Party Driven Relocations	Third-party driven
New Extensions	Growth
Overhead Line Rebuilds, Replacements and Life Extension	Asset replacement or refurbishment
Wood Pole Replacement and Life Extension	Asset replacement or refurbishment
Reliability	Asset replacement or refurbishment
Wild Fire Mitigation	Third-party driven
New programs	
Distribution Automation	None
Transmission Driven	Third-party driven ⁵⁴⁹
Underground Rebuilds, Replacements and Life Extension	Asset replacement or refurbishment ⁵⁵⁰

513. Regarding the Distribution Automation program, ATCO Electric submitted that although this program does not align with any one of the Criterion 2 project types, it is “sufficiently important to the company, so that its ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken.”⁵⁵¹

514. No party took issue with ATCO Electric’s evidence referenced in the table above in support of how the projects or programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis satisfy the requirements of Criterion 2.

⁵⁴⁷ Exhibit 20555-X0007, application, paragraph 133.

⁵⁴⁸ Exhibit 20555-X0007, application, paragraph 127.

⁵⁴⁹ Exhibit 20555-X0007, application, paragraphs 167-170.

⁵⁵⁰ Exhibit 20555-X0007, application, paragraphs 153-155.

⁵⁵¹ Exhibit 20555-X0007, application, paragraphs 182-183.

Commission findings

515. Consistent with the determinations in Section 3 of this decision, because the driver or drivers (e.g., replacement of existing assets, external party, growth) for each project or program included in ATCO Electric's 2014 capital tracker true-up have not changed since the Commission undertook and approved proposed capital tracker projects and programs against the Criterion 2 requirements in Decision 3218-D01-2015,⁵⁵² there is no need to undertake a reassessment of these projects or programs against the Criterion 2 requirements.

516. The Commission reminds ATCO Electric that the following direction from Decision 3218-D01-2015 continues to apply for subsequent capital tracker true-up applications:

502. In subsequent capital tracker true-up applications, the Commission directs ATCO Electric to address whether the driver for any of the previously approved forecast projects or programs has changed, so as to warrant a reassessment under Criterion 2. In the event that the driver of the project or program has changed since the forecast project or program was approved, ATCO Electric is directed to identify such projects and programs and to provide evidentiary support that each project or program continues to satisfy the requirements of Criterion 2.⁵⁵³

517. The Commission has reviewed the evidence and the reasons provided by ATCO Electric in support of its applied-for 2016-2017 capital tracker projects and programs, as summarized in Table 41 above. As set out in Section 3 of this decision, for capital tracker projects or programs for which the Commission undertook and approved the assessment against the Criterion 2 requirements in prior capital tracker decisions, there is no need to undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program has changed. ATCO Electric confirmed that "all project or program drivers for previously approved trackers have not changed."⁵⁵⁴

518. For new capital tracker projects or programs proposed for 2016-2017, the Commission finds that the driver for each of ATCO Electric's proposed capital tracker projects and programs, with the exception of the Distribution Automation program, falls into one or more of the following Criterion 2 categories: asset replacement or refurbishment, required by an external party or growth related. Regarding the Distribution Automation program, the Commission notes that in Section 6.3.1, it made a findings that the Distribution Automation program does not satisfy the project assessment requirement of Criterion 1, and therefore, will not make any further comment regarding assessment of this program against Criterion 2. For the reasons above, with the exception of the Distribution Automation program, the Commission finds that ATCO Electric's projects or programs presented in Table 41 satisfy the requirements of Criterion 2.

9 Criterion 3 – The project must have a material effect on the company's finances

519. Section 7 of this decision addressed ATCO Electric's accounting test, which determines whether all of the forecast or actual expenditures for a capital project are, or a portion is, outside the normal course of the company's ongoing operations, as required to satisfy Criterion 1. This is

⁵⁵² Exhibit 20555-X0007, application, paragraph 24.

⁵⁵³ Decision 3218-D01-2015, paragraph 502.

⁵⁵⁴ Exhibit 20555-X0007, application, paragraph 24.

established by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project proposed for capital tracker treatment.

520. In accordance with the Commission's determinations in Decision 2013-435, the portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year, calculated as part of the accounting test, is then assessed against the two-tiered materiality test under Criterion 3. The first tier of the materiality threshold, a "four basis point threshold," is applied at a project level, grouped in the manner approved by the Commission. The second tier of the materiality threshold, a "40 basis point threshold," is applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.⁵⁵⁵

521. In Decision 2013-435, the Commission calculated the four basis point threshold and the 40 basis point threshold based on the dollar value of ATCO Electric's ROE in 2012. The Commission indicated that in subsequent PBR years, the four basis point threshold and the 40 basis point threshold are to be calculated by escalating the 2012 amount by I-X.⁵⁵⁶

522. For the 2014 capital tracker true-up, ATCO Electric used the 2014 four basis point threshold of \$0.228 million and the 2014 40 basis point threshold of \$2.274 million previously approved in Decision 3218-D01-2015,⁵⁵⁷ calculated by escalating the 2012 amount by the approved 2013 and 2014 I-X index values. ATCO Electric used these approved materiality threshold values in its 2014 true-up application to demonstrate that the applied-for 2014 capital tracker programs satisfied the requirements of Criterion 3.⁵⁵⁸

523. For the 2016 and 2017 capital tracker forecast, ATCO Electric calculated the materiality thresholds following the methodology set out in Decision 2013-435. However, as discussed in Section 7.1, since at the time the application was filed, ATCO Electric did not have the approved I factors for either 2016 or 2017, it used the 2015 I-X index value of 1.49 per cent for 2016 and 2017 as the forecast rate.⁵⁵⁹

524. ATCO Electric calculated the 2016 four basis point threshold of \$0.234 million by escalating the 2012 amount by the approved I-X index values for 2013, 2014, and 2015 as well as the forecast I-X index value for 2016. Similarly, ATCO Electric calculated the 40 basis point threshold to be \$2.342 million for 2016. Using the same methodology, ATCO Electric calculated the 2017 four basis point threshold to be \$0.238 million and the 40 basis point threshold to be \$2.377 million.⁵⁶⁰

525. ATCO Electric then assessed each of the capital tracker projects or programs included in the 2016 and 2017 forecast against the four basis point threshold, and the total K factor amount associated with all capital tracker projects or programs in each of 2016 and 2017 against the

⁵⁵⁵ Decision 2013-435, paragraphs 382-385.

⁵⁵⁶ Decision 2013-435, paragraphs 378 and 384.

⁵⁵⁷ Decision 3218-D01-2015, paragraph 511.

⁵⁵⁸ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a), Attachment 1 (revised Appendix A - Project Net Cost K Factor Revenue Requirement Schedules), Schedule 1-1.

⁵⁵⁹ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a) Attachment 1 (revised Appendix A - Project Net Cost K Factor Revenue Requirement Schedules), Schedule 1-1.

⁵⁶⁰ Exhibit 20555-X0007, application, paragraph 190.

40 basis point threshold. ATCO Electric submitted that its proposed capital tracker projects or programs satisfy the materiality test requirement of Criterion 3.⁵⁶¹

526. No party took issue with ATCO Electric's calculation of its 2016 or 2017 materiality thresholds under Criterion 3.

Commission findings

527. For its 2014 true-up calculations, ATCO Electric used the first and second tier materiality thresholds approved in Decision 3218-D01-2015,⁵⁶² based on the approved 2013 and 2014 I-X index values. For 2016 and 2017, ATCO Electric calculated the first and second tier materiality thresholds by escalating the respective 2012 values by the approved 2013, 2014, and 2015 I-X indexes, and then used the approved 2015 I-X index value as a placeholder for 2016 and 2017 I-X index values. As discussed in Section 7.1, given that ATCO Electric did not have an approved I factor for either 2016 or 2017 when it filed the application, it used the approved 2015 I-X index value as a placeholder for 2016 and 2017. The Commission accepts, in principle, the use of this forecasting method given that final approved numbers were not available.

528. However, since the filing of the application, the 2016 I-X index of 0.90 per cent has been approved in Decision 20822-D01-2015.⁵⁶³ Consistent with the findings in Section 7.1, to minimize future true-ups, the Commission directs ATCO Electric, in its compliance filing to this decision, to use the approved 2016 I-X index value of 0.90 per cent to calculate the first and second tier materiality thresholds for 2016.

529. The Commission has reviewed ATCO Electric's calculations, and is generally satisfied that ATCO Electric has interpreted and applied the Criterion 3 two-tiered materiality test properly for the purposes of its 2014 true-up and 2016 and 2017 capital tracker forecasts based on the projects and assumptions included in the application. However, as discussed earlier in this section, the two-tiered materiality test under Criterion 3 is applied to the portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year, calculated as part of the accounting test. In Section 7.3, the Commission directed ATCO Electric, in its compliance filing to this decision, to revise its accounting test based on approved 2016 and 2017 forecast capital additions and changes to the 2016 model assumptions to reflect the approved 2016 I-X index value. Accordingly, because ATCO Electric's accounting test for each of 2016 and 2017 needs to be revised, the Commission cannot determine in this decision whether any of ATCO Electric's projects or programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis satisfy the materiality test requirement of Criterion 3. In addition, as set out in sections 6.2.3.5, 6.2.4 and 6.3.1 of this decision, the Commission directed ATCO Electric, in its compliance filing to this decision, to remove certain or all costs related to the Fort McMurray North Service Building project, information technology projects and the Distribution Automation program from its K factor calculations.

530. Given these findings, the Commission directs ATCO Electric, in its compliance filing to this decision, to reassess whether its projects or programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis, satisfy the two-tiered materiality test requirement of

⁵⁶¹ Exhibit 20555-X0007, application, paragraphs 146, 156, 171 and 184.

⁵⁶² Decision 3218-D01-2015, paragraph 511.

⁵⁶³ Decision 20822-D01-2015, paragraph 21.

Criterion 3. For this reassessment, ATCO Electric will use the approved 2014 threshold amount, as well as revised 2016 threshold amounts, as directed above.

10 Other matters

10.1 Additional issues raised by interveners in argument and reply argument

531. In argument, the CCA and UCA raised three issues not specifically addressed elsewhere in this decision. The first issue related to ATCO Electric's ratio of internal staff to contracted staff. The second issue related to the effect of the ATCO Group layoffs reported in the media in November 2015. The third issue related to the reporting of information under Rule 005.

532. Regarding the first issue, in a Commission IR response ATCO Electric indicated that it will be replacing its contracted line crews with internal line crews over time.⁵⁶⁴ The CCA recommended that the Commission direct ATCO Electric to record the ratio of internal staff to contracted staff for each year, because the shift from contracted to internal labour is important in terms of forecasting costs and overhead.⁵⁶⁵ In reply, ATCO Electric clarified its strategy with respect to its internal/contracted staff ratio, explaining that "the size of the internal crews is managed to ensure that a base level of work is completed through internal crews and the peaks are handled through the use of contractor crews."⁵⁶⁶

533. Regarding the second issue, the ATCO Group announced layoffs shortly before the hearing for this application commenced. The CCA submitted that ATCO Electric declined to provide any information with respect to the layoff details⁵⁶⁷ and, "Given the ambiguity and lack of support for the trackers which the layoffs represent," recommended that the interim capital tracker K factor placeholder be reduced to 75 per cent.⁵⁶⁸ Although this recommendation differed from the 90 per cent K factor placeholder that the CCA recommended in the 2016 annual PBR rate adjustment proceeding, this recommendation was made prior to the layoffs being announced. The CCA observed that although capital tracker forecasts are trued up, ATCO Electric would benefit from the earnings impact of the layoffs during the intervening period, and therefore recommended that the interim capital tracker rates be reduced to 75 per cent. The CCA acknowledged that this recommendation differed from the 90 per cent placeholder that it recommended in the 2016 annual PBR rate adjustment proceeding.⁵⁶⁹

534. The third issue was raised by the UCA in its written argument and is in regards to the K factor amounts reflected in ATCO Electric's 2013 and 2014 Rule 005 filings. The UCA stated that given the regulatory lag between the approval of K factors, either on a forecast or final basis, and the filing of ATCO Electric's Rule 005 report, which is filed in May of the year following the end of the Rule 005 reporting year, there exists "the potential that a portion of the K Factor approved by the Commission in any given year will not be reflected in any of the utility's Rule 005 filings."⁵⁷⁰ The UCA was concerned that this made it difficult to assess whether a re-opener has been triggered, as allowed for under the PBR plan established by the Commission in

⁵⁶⁴ Exhibit 20555-X0023, AE-AUC-2015JUL20-038(a).

⁵⁶⁵ Exhibit 20555-X0076, CCA argument, paragraphs 123-124.

⁵⁶⁶ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 99.

⁵⁶⁷ Exhibit 20555-X0081, CCA reply argument, paragraph 70.

⁵⁶⁸ Exhibit 20555-X0081, CCA reply argument, paragraph 78.

⁵⁶⁹ Exhibit 20555-X0081, CCA reply argument, paragraphs 70-78.

⁵⁷⁰ Exhibit 20555-X0076, UCA argument, paragraph 11.

Decision 2012-237. The UCA recommended that the Commission direct ATCO Electric to update its 2014 Rule 005 filing to include all revenue that it recorded in 2014, including 2013 K factor revenue that was collected in 2014, in the compliance filing to this decision.⁵⁷¹

535. The CCA, in its reply argument, supported the UCA's recommendation on the basis that the annual Rule 005 filings should reflect a correct matching of costs and revenues to determine ROE. Furthermore, the CCA submitted that it is difficult to evaluate the performance of ATCO Electric during the PBR term without the recommended information included in the Rule 005 filings.⁵⁷²

536. In ATCO Electric's view, no evidence had been put forward "to suggest that it would be appropriate for updates to be made to the 2014 Rule 005 report" and that changes to Rule 005 should not be made in this proceeding given that such changes would affect parties that were not participating in this proceeding. ATCO Electric submitted that the UCA's recommendation be dismissed.⁵⁷³

Commission findings

537. With respect to the first issue raised by the CCA, in light of the layoffs by the ATCO Group, the Commission finds that internal/contracted staff ratio information may be helpful in assessing whether the overhead allocation rates and the costs of a project or program are prudent on an actual basis. However, given the interim nature of the funding for the 2016 and 2017 capital tracker forecast project expenditures, the Commission does not consider that this information is required to justify the 2016 and 2017 forecast. ATCO Electric is directed to provide its internal/contracted staff ratio to assist the Commission and parties in assessing the prudence of the overhead allocation rates and the actual costs of a project or program, as part of its applications in subsequent capital tracker true-up proceedings.

538. Regarding the second issue, the CCA proposed a reduction to the Commission's decision to award an interim K factor placeholder of 90 per cent for 2016 to 75 per cent. In Decision 20822-D01-2015, the Commission approved a 90 per cent K factor placeholder for ATCO Electric for 2016 as "...reasonable given that the company's 2016 capital tracker forecast application was still ongoing and that approval at this level would provide timely funding to ATCO Electric while also maintaining rate stability and preventing rate shock."⁵⁷⁴ The CCA's submission amounts to a request for the Commission to initiate a review and variance proceeding of Decision 20822-D01-2015 on the basis of a change in circumstances that was not known at the time that the interim decision was issued. The Commission is not persuaded that a review of the interim decision is warranted in these circumstances. There is no suggestion that ATCO Electric withheld information from the Commission or parties during the interim rate application proceeding. Further, interim decisions are just that, interim, which allows for adjustments when final revenue requirement is determined. The capital tracker true-up process is intended to adjust all related costs that have been approved on a forecast basis to actual costs, recognizing that actual costs will differ from forecast costs.

⁵⁷¹ Exhibit 20555-X0076, UCA argument, paragraph 12.

⁵⁷² Exhibit 20555-X0081, CCA reply argument, paragraphs 11 and 13.

⁵⁷³ Exhibit 20555-X0080, ATCO Electric reply argument, paragraph 43.

⁵⁷⁴ Decision 20822-D01-2015, paragraph 83.

539. With respect to the third issue, the Commission notes that following the close of record for this proceeding, the Commission issued Bulletin 2016-03⁵⁷⁵, which provides clarifications with respect to the annual Rule 005 filings. In Bulletin 2016-03, the Commission stated, in part:

Consistent with the Commission's determinations in decisions 3218-D01-2015 and 3267-D01-2015, companies under the current generation of PBR plans will not be required to restate previous year Rule 005 filings to reflect updates from a placeholder to either a confirmed placeholder or final approved values, including K factor amounts issued after the reporting year reflected in the Rule 005 filing.⁵⁷⁶

540. The Commission considers that the issue raised in this proceeding with respect to ATCO Electric's 2014 Rule 005 filing is dealt with in Bulletin 2016-03, which applies to all distribution utilities under the current PBR plan. Additionally, as noted in Bulletin 2016-03, the issue of how to calculate returns for the purpose of assessing reopeners under the PBR plan is being considered on a go-forward basis for the second generation PBR, in Proceeding 20414, which is currently ongoing.⁵⁷⁷

11 2014 true-up and 2016-2017 forecast K factor calculations

541. In Decision 2014-295,⁵⁷⁸ the Commission approved a 90 per cent placeholder for ATCO Electric's 2014 capital tracker K factor quantities. In Decision 20369-D01-2015 (Errata), the Commission approved the 2014 forecast K factor of \$35.7 million to be recovered from ATCO Electric's customers on an interim basis.⁵⁷⁹ As part of the 2014 capital tracker true-up, ATCO Electric calculated its actual 2014 K factor to be \$26.3 million,⁵⁸⁰ resulting in a proposed 2014 K factor true-up adjustment of \$9.5 million to be refunded to customers, as shown in Table 1 from Section 4 of this decision.

542. In Decision 20822-D01-2015,⁵⁸¹ the Commission approved a 90 per cent placeholder for ATCO Electric's 2016 capital tracker K factor quantities. This 90 per cent placeholder was based on the 2016 K factor amount under consideration in this application. As summarized in Table 2 from Section 4 of this decision, ATCO Electric calculated the 2016 and 2017 forecast K factors to be \$48.2 million and \$61.1 million, respectively.⁵⁸²

Commission findings

543. In Section 6 of this decision, the Commission confirmed the prudence of actual capital additions associated with ATCO Electric's projects or programs included in the 2014 capital tracker true-up. Accordingly, the Commission approves the 2014 K factor adjustment of \$9.5 million for ATCO Electric as final, and in the compliance filing to this decision, directs

⁵⁷⁵ Bulletin 2016-03, Clarification of Rule 005 financial reporting requirements, February 2, 2016.

⁵⁷⁶ Bulletin 2016-03, page 6.

⁵⁷⁷ Bulletin 2016-03, page 4.

⁵⁷⁸ Decision 2014-295: ATCO Electric Ltd., 2014 Interim Rates, Proceeding 3239, Application 1610590-1, October 24, 2014.

⁵⁷⁹ Decision 20369-D01-2015, paragraph 73.

⁵⁸⁰ Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a) Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules), Schedule 1-1, row 29, column AH.

⁵⁸¹ Decision 20822-D01-2015, paragraph 83.

⁵⁸² Exhibit 20555-X0022, AE-AUC-2015JUL20-010(a), Attachment 1 (revised Appendix A - Project Net Cost K-Factor Revenue Requirement Schedules), Schedule 1-1, row 29, columns AV and BH.

ATCO Electric to propose how the difference between the 2014 K factor amount included in ATCO Electric's 2014 interim rates application and the approved 2014 K factor true-up adjustment will be refunded to its customers in its rates.

544. With respect to the 2016 and 2017 forecast K factors, the Commission finds that ATCO Electric has used the correct inputs in its calculations. The Commission has also reviewed the K factor calculations and is satisfied that the calculations have generally been performed correctly and in accordance with previous Commission directions. However, as set out in sections 6.2.3.5, 6.2.4 and 6.3.1 of this decision, the Commission directed ATCO Electric, in its compliance filing to this decision, to remove certain or all costs related to the Fort McMurray North Service Building project, information technology projects and the Distribution Automation program from its K factor calculations. With the exception of these projects, the Commission determined that ATCO Electric's forecast capital expenditures for the proposed 2016 and 2017 capital tracker projects or programs were generally reasonable, subject to adjusting certain labour escalation factors. In sections 7.3 and 9, the Commission directed ATCO Electric, in its compliance filing to this decision, to revise its accounting test assessment under Criterion 1 and the two-tiered materiality test assessment under Criterion 3 for 2016. Because these revisions will result in changes to the 2016 and 2017 forecast K factor amounts, the Commission cannot approve 2016 or 2017 K factor adjustments for ATCO Electric, on a forecast basis, in this decision.

545. Nevertheless, the Commission has reviewed ATCO Electric's calculations and finds that ATCO Electric's methodology to determine the 2014 K factor true-up amount and the 2016 and 2017 K factor forecast amounts is generally consistent with the requirements set out in Decision 2012-237 and Decision 2013-435.

546. Consistent with ATCO Electric's past practices, the Commission considers that ATCO Electric should propose a method to collect the difference between the respective 2016 and 2017 K factor placeholder amounts and the approved 2016 and 2017 K factor forecast amounts. The final 2016 and 2017 K factor amounts will be reviewed by the Commission in the compliance filing to this decision.

547. In summary, the Commission directs ATCO Electric to update the 2016 and 2017 forecast amounts of \$48.2 million and \$61.1 million, respectively, in the compliance filing to this decision to give effect to:

- The 2016 I-X index and the Q factor, as per recently released in Decision 20822-D01-2015, as directed in Section 7.1 of this decision.
- The approved labour escalation rates, as directed in Section 6.1.1.1 of this decision.
- The projects that were denied capital tracker treatment: Fort McMurray North Service Building project, information technology projects and the Distribution Automation program.

12 Compliance with previous Commission directions

548. In Decision 3218-D01-2015, the Commission provided a number of directions to ATCO Electric that were applicable to its future capital tracker applications. In Decision 3434-D01-2015 and Decision 3558-D01-2015, the Commission also provided clarifications on the capital

tracker mechanism and issued a number of related directions to companies under PBR, including ATCO Electric.

549. With the exception of one Commission direction in Decision 3218-D01-2015, discussed below, ATCO Electric has addressed the Commission's directions in the application and provided three summary tables⁵⁸³ to demonstrate its compliance with the Commission's directions. The tables are summarized in Appendix 4 to this decision.

550. In Decision 3218-D01-2015, the Commission directed ATCO Electric:

562. ... to provide evidence in future capital tracker applications on the effect, if any, of the separation of its distribution and transmission functions on the applied-for capital trackers. Where there is an effect on the applied-for capital trackers, ATCO Electric shall provide an explanation and quantification of the effect.⁵⁸⁴

551. In the application, ATCO Electric submitted that the effect of any distribution and transmission function split, on capital trackers applied for in this proceeding, is minimal.⁵⁸⁵

552. The CCA expressed a concern that because ATCO Electric does not appear to have an allocation methodology and it might not be recording the transfer of employees from the distribution function to the transmission function, capital trackers may include costs that should not be allocated to the distribution function. To support its concern, the CCA cited the following exchange between its counsel and ATCO Electric:⁵⁸⁶

Q. Okay. And, sir, what would happen, though, if a staff person is forecast -- and let's just try to pick a year here. So we've gone through a year of PBR; 2013 comes to an end. Internally the company has forecast someone to be a Distribution staffer, but they're moved to Transmission very early on in 2015, because I was using '14 year-end. Does that kind of reassignment of the staff person change allocations at all, or what does the company do to track it?

A. MR. HOWELL: No. The answer is no. And the response to what we do to track it is we monitor complement positions and which ones have incumbents and which ones might be vacant. But we certainly -- if Employee A was in High Level and he moved to a Transmission job in High Level from Distribution, then he would be moving into a Transmission complement position that we had -- had always considered to be Transmission. And if that move actually ended up changing their complement, then we would record that. So we track the complement, not the actual employee's name.

553. In reply, ATCO Electric submitted that "the exchange referenced in the CCA Argument was in the context of the High Level building allocations between Transmission and Distribution and has no bearing on the tracking of appropriate staffing costs between the Transmission and Distribution divisions" because employee transfers do not impact the space requirements of the two functions.⁵⁸⁷

⁵⁸³ Exhibit 20555-X0007, application, tables 2.0-1, 2.0-2 and 2.0-3.

⁵⁸⁴ Decision 3218-D01-2015, paragraph 562.

⁵⁸⁵ Exhibit 20555-X0007, application, Table 2.0-1, Direction 19.

⁵⁸⁶ Exhibit 20555-X0076, paragraphs 38-39.

⁵⁸⁷ Exhibit 20555-X0080, ATCO Electric reply argument, paragraphs 63-64.

554. In discussion with UCA counsel, regarding the allocation of space in the Drumheller building, ATCO Electric stated that it was “not sure what the exact allocations to Transmission will be or just how that will turn out.”⁵⁸⁸ In an exchange between Mr. Howell and Commission counsel, regarding the increased actual building size in Drumheller, there appeared to be some confusion around the transmission function’s share of the building square footage.⁵⁸⁹ Also, in response to a Commission IR, ATCO Electric noted that the forecast cost in the application for the High Level Service Building capital tracker project included the transmission function’s share of the project, and subsequently corrected the accounting test to account for the allocation of the respective separate functions.⁵⁹⁰

Commission findings

555. In previous sections of this decision, the Commission dealt with ATCO Electric’s compliance with certain directions from Decision 3218-D01-2015, as well as Decision 3434-D01-2015 and Decision 3558-D01-2015. Specifically, in Section 5 of this decision, the Commission noted that ATCO Electric provided descriptions of its non-capital tracker projects or programs, and thus complied with the direction from Decision 3558-D01-2015. In sections 6.1.2 and 6.1.3, respectively, the Commission found that ATCO Electric complied with the directions to provide a summary of the services provided by or to an affiliate, and the related costs and an explanation of how those amounts were determined, and to describe its formal project management policies and procedures. In Section 7.1, the Commission also noted that ATCO Electric provided sufficient details regarding its income tax calculations and also provided an accounting test model with linked and working formulas, as directed in Decision 3218-D01-2015. Other than as mentioned in the above specific sections, interveners did not challenge ATCO Electric’s compliance with Commission directions.

556. At paragraph 562 of Decision 3218-D01-2015, the Commission directed ATCO Electric to provide evidence with respect to the allocation of costs between the distribution and transmission functions:

562. The Commission directs ATCO Electric to provide evidence in future capital tracker applications on the effect, if any, of the separation of its distribution and transmission functions on the applied-for capital trackers. Where there is an effect on the applied-for capital trackers, ATCO Electric shall provide an explanation and quantification of the effect.⁵⁹¹

557. Although this direction was prompted as a result of a concern with overhead allocations in Proceeding 3218, the Commission considers that this information is required for any type of transmission/distribution allocation, including building space allocations. As such, the Commission finds that this requirement was not complied with in ATCO Electric’s original filing of the application. The Commission observes that in the proceeding, it was able to obtain the requisite information via IR responses,⁵⁹² and therefore does not require additional transmission/distribution allocation information at this time. However, the Commission reminds ATCO Electric that the direction at paragraph 562 from Decision 3218-D01-2015 continues to

⁵⁸⁸ Transcript, Volume 2, page 262, lines 20-21 (Mr. Howell).

⁵⁸⁹ Transcript, Volume 2, pages 316-341 (Mr. Howell).

⁵⁹⁰ Exhibit 20555-0023, AE-AUC-2015JUL20-020(a).

⁵⁹¹ Decision 3218-D01-2015, paragraph 562.

⁵⁹² Exhibit 20555-0023, AE-AUC-2015JUL20-020.

apply for subsequent capital tracker applications, and that the Commission expects this information to be included in future applications.

558. The Commission has reviewed ATCO Electric's responses to the directions of the Commission not specifically addressed in the previous sections of this decision, and with the exception of the requirement to provide evidence in future capital tracker applications on the effect of the separation of its distribution and transmission functions on the applied-for capital trackers, the Commission is generally satisfied that ATCO Electric complied with these directions in the proceeding. Given the transmission function's share of the square footage of the Drumheller Service Building is unknown at this time, and in light of the error in the application regarding the transmission function's share of the High Level Service Building, the Commission directs ATCO Electric to provide the distribution and transmission function allocations for each of its building projects in future capital tracker true-up applications.

13 Order

559. It is hereby ordered that:

- (1) ATCO Electric Ltd. is directed to file a compliance filing application in accordance with the directions contained within this decision on or before April 14, 2016.

Dated on March 3, 2016.

Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Neil Jamieson
Commission Member

(original signed by)

Bill Lyttle
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Electric Ltd (ATCO Electric or AE) Bennett Jones LLP
Consumers' Coalition of Alberta (CCA)
Office Of The Utilities Consumer Advocate (UCA) Brownlee LLP

Alberta Utilities Commission Commission panel M. Kolesar, Vice-Chair N. Jamieson, Commission Member B. Lyttle, Commission Member Commission staff K. Kellgren (Commission counsel) J. Graham (Commission counsel) A. Corsi B. Miller N. Mahbub J. Work G. Nadeau E. Deryabina

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
ATCO Electric Ltd. L. Smith, QC M. Buchinski	B. McNabb B. Howell M. Sveinbjornson J. Claude
Consumers' Coalition of Alberta (CCA) J. Wachowich S. Gibbons	
Office of the Utilities Consumer Advocate (UCA) T. Marriott, QC	R. Bell

Alberta Utilities Commission Commission panel M. Kolesar, Vice-Chair N. Jamieson, Commission Member B. Lyttle, Commission Member Commission staff K. Kellgren (Commission counsel) J. Graham (Commission counsel) A. Corsi N. Mahbub J. Work G. Nadeau B. Miller

Appendix 3 – Summary of Commission directions

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

1. ATCO’s Electric’s Office Furniture program and EPCOR’s Furniture Life Cycle Replacement Program appear similar enough to warrant an exploration of whether ATCO Electric’s Office Furniture program can be grouped with the Buildings, Structures and Leasehold Improvements program. Therefore, for the true-up of its 2015 capital tracker application, ATCO Electric is directed to explain why the Office Furniture program should be a separate program and not a part of the Buildings, Structures and Leasehold Improvements program. Paragraph 71
2. Nonetheless, the evidence in this proceeding suggests that the forecasts for economic growth in Alberta since ATCO Electric filed its application have trended downwards for 2016 and 2017. The effects of lower economic growth in Alberta are further illustrated in ATCO Electric’s actual 2015 non-union labour inflation rate of 0.6 per cent. The Commission notes that when ATCO Electric filed its application, economic forecasts were predicting growth to recover in 2016 as compared to 2015. However, during the hearing, updated growth forecasts were provided which indicated that economic growth in 2016 would experience a more “gradual recovery” than originally anticipated. In light of the updated economic growth forecasts and ATCO Electric’s evidence that its labour inflation rates take into account the “outlook of the labour market,” the Commission does not find ATCO Electric’s non-union labour inflation rates for 2016 and 2017 of 3.75 per cent to be reasonable. The Commission finds that a more moderate non-union labour inflation rate for 2016 and 2017 of 3.00 per cent is reasonable for the purpose of the accounting test to be used in forecasting 2016 and 2017 capital tracker expenditures, given the lower economic growth forecasts for Alberta. ATCO Electric is directed to reflect these non-union labour inflation rates in its compliance filing application to this decision. Paragraph 97
3. Regarding ATCO Electric’s union labour inflation rate for 2016 of 3.75 per cent, the Commission recognizes that this rate was negotiated in an agreement that was ratified on October 7, 2014. Accordingly, the Commission approves the 2016 union inflation rate as filed. For the 2017 union labour inflation rate, the Commission considers that a forecast that better reflects current economic expectations for 2017 is warranted. Accordingly, consistent with the non-union labour inflation rates for 2016 and 2017, the Commission finds that a union labour inflation rate of 3.00 per cent is reasonable for the purpose of the accounting test to be used in forecasting 2017 capital tracker expenditures. ATCO Electric is directed to reflect this 2017 union labour inflation rate in its compliance filing application to this decision. Paragraph 98
4. For 2016 and 2017, ATCO Electric forecast contractor inflation rates to be two per cent and four per cent, respectively. ATCO Electric stated that the 2016 rate was based on the weakened economic conditions it had experienced in 2015, with the expectation that conditions would improve by 2017. As discussed above, with respect to the labour inflation rates, the Commission notes that since ATCO Electric filed its application, economic growth forecasts for 2016 and 2017 have decreased. While ATCO Electric

- indicated that it accounted for the downward trend in economic conditions in its 2016 contractor inflation forecast, the Commission finds that an adjustment to the 2017 forecast is required to reflect the most up to date information on the record. The Commission considers that a three per cent contractor inflation rate for 2017 is reasonable for the purpose of the accounting test to be used in forecasting 2016 and 2017 capital tracker expenditures, given that it is a mid-point between ATCO Electric's 2016 forecast and its 2017 forecasts and reflects the lower economic growth forecast for 2017. ATCO Electric is directed to reflect this 2017 contractor inflation rate in its compliance filing application to this decision. Paragraph 99
5. The Commission has reviewed ATCO Electric's project management policies and procedures in light of the directions given at paragraph 520 of Decision 3218-D01-2015. The Commission finds that ATCO Electric provided a sufficient explanation of its controls and accountability procedures with respect to the initiation, planning, design, execution and review of its capital projects. Accordingly, the Commission finds that ATCO Electric has complied with the direction set out at paragraph 520 of Decision 3218-D01-2015. The Commission directs ATCO Electric to confirm that these policies and procedures continue to be in place and to advise the Commission of improvements and modifications to these policies and procedures in future capital tracker applications. Paragraph 139
 6. With respect to the scope, level and timing of this program for 2016 and 2017, the Commission has reviewed the updated business case and the relevant portions of the record for this program and finds the forecast scope, level and timing of this program for 2016 and 2017 to be reasonable. ATCO Electric's forecast capital additions associated with the Distribution to Transmission Contributions program are \$16.4 million in 2016 and \$36.2 million in 2017. During the hearing, ATCO Electric provided CCDs for the Thorton 2091S and Mowat 2033S projects, which were not available when the application was filed, in an undertaking response. The Commission considers that in assessing the reasonableness of the forecast capital additions for the Distribution to Transmission Contributions program, the Commission requires the most recent cost information available. Accordingly, in its compliance filing to this decision, the Commission directs ATCO Electric to use the updated CCD amounts in calculating the K factor for this program. Paragraph 188
 7. However, the Commission is not making a finding with respect to the costs associated with Phase 2 of the project, which could potentially include space beyond the approved area of 50,014 sq. ft., but is expected to be closer to the area approved by the Commission for the Drumheller Service Building in Decision 2013-358 and Decision 3218-D01-2015. The Commission will review the Phase 2 costs including the final allocation of space between the transmission and distribution function and the resultant effects if any upon any amounts added in 2014, in the 2015 true-up proceeding. In its 2015 true-up, ATCO Electric is directed to address any differences in the final area and costs from those approved by the Commission in Decision 2013-358 and Decision 3218-D01-2015. ATCO Electric is also directed to provide an explanation for differences in the final allocation of space between its distribution and transmission functions from the allocations approved by the Commission in Decision 2013-358. Paragraph 225
 8. In Decision 3218-D01-2015, the Commission found that, "While the Commission is unable to make a finding with respect to capital tracker treatment for the actual and

- forecast capital costs associated with the training facility component of the project at this time, the Commission notes the statement made at paragraph 48 of Decision 2013-435, that a company may apply for capital tracker treatment of capital expenditures after the capital additions are made.” Accordingly, ATCO Electric is permitted to include in its K factor the revenue requirement associated with the capital additions in 2013, that is not funded by the I-X mechanism. ATCO Electric is directed to include this amount in its compliance filing. Paragraph 242
9. ATCO Electric proposed in its application that the forecast values of the I and Q factors will be trued up to approved numbers as part of the 2016 and 2017 capital tracker true-up applications. However, regarding the 2016 forecast, the Commission observes that, since the filing of the application, the 2016 I-X index of 0.90 per cent and billing determinants forecast were approved in Decision 20822-D01-2015. To minimize future true-ups, the Commission directs ATCO Electric, in its compliance filing to this decision, to use the approved 2016 I-X index value and the Q factor based on the forecast billing determinants approved in Decision 20822-D01-2015 for purposes of its 2016 capital tracker forecast accounting test. For the purpose of this decision, the Commission considers ATCO Electric’s forecast I and Q values for 2017 to be reasonable. Paragraph 479
 10. The Commission directs ATCO Electric, in its compliance filing to this decision, to revise its accounting test for 2016 and 2017, based on approved final forecast or actual capital additions, the 2016 model assumptions and other directions as set out in this decision. ATCO Electric is further directed to provide a summary table in the compliance filing to this decision, showing for each capital tracker project or program, a comparison of the 2016 and 2017 forecast capital additions applied for in this proceeding and the 2016 and 2017 forecast capital additions, revised in accordance with the directions set out in this decision. Paragraph 509
 11. However, since the filing of the application, the 2016 I-X index of 0.90 per cent has been approved in Decision 20822-D01-2015. Consistent with the findings in Section 7.1, to minimize future true-ups, the Commission directs ATCO Electric, in its compliance filing to this decision, to use the approved 2016 I-X index value of 0.90 per cent to calculate the first and second tier materiality thresholds for 2016. Paragraph 528
 12. Given these findings, the Commission directs ATCO Electric, in its compliance filing to this decision, to reassess whether its projects or programs proposed for capital tracker treatment in 2016 and 2017 on a forecast basis, satisfy the two-tiered materiality test requirement of Criterion 3. For this reassessment, ATCO Electric will use the approved 2014 threshold amount, as well as revised 2016 threshold amounts, as directed above. Paragraph 530
 13. With respect to the first issue raised by the CCA, in light of the layoffs by the ATCO Group, the Commission finds that internal/contracted staff ratio information may be helpful in assessing whether the overhead allocation rates and the costs of a project or program are prudent on an actual basis. However, given the interim nature of the funding for the 2016 and 2017 capital tracker forecast project expenditures, the Commission does not consider that this information is required to justify the 2016 and 2017 forecast. ATCO Electric is directed to provide its internal/contracted staff ratio to assist the Commission and parties in assessing the prudence of the overhead allocation rates and the actual costs

- of a project or program, as part of its applications in subsequent capital tracker true-up proceedings. Paragraph 537
14. In Section 6 of this decision, the Commission confirmed the prudence of actual capital additions associated with ATCO Electric’s projects or programs included in the 2014 capital tracker true-up. Accordingly, the Commission approves the 2014 K factor adjustment of \$9.5 million for ATCO Electric as final, and in the compliance filing to this decision, directs ATCO Electric to propose how the difference between the 2014 K factor amount included in ATCO Electric’s 2014 interim rates application and the approved 2014 K factor true-up adjustment will be refunded to its customers in its rates.
..... Paragraph 543
15. In summary, the Commission directs ATCO Electric to update the 2016 and 2017 forecast amounts of \$48.2 million and \$61.1 million, respectively, in the compliance filing to this decision to give effect to:
- The 2016 I-X index and the Q factor, as per recently released in Decision 20822-D01-2015, as directed in Section 7.1 of this decision.
 - The approved labour escalation rates, as directed in Section 6.1.1.1 of this decision.
 - The projects that were denied capital tracker treatment: Fort McMurray North Service Building project, information technology projects and the Distribution Automation program. Paragraph 547
16. The Commission has reviewed ATCO Electric’s responses to the directions of the Commission not specifically addressed in the previous sections of this decision, and with the exception of the requirement to provide evidence in future capital tracker applications on the effect of the separation of its distribution and transmission functions on the applied-for capital trackers, the Commission is generally satisfied that ATCO Electric complied with these directions in the proceeding. Given the transmission function’s share of the square footage of the Drumheller Service Building is unknown at this time, and in light of the error in the application regarding the transmission function’s share of the High Level Service Building, the Commission directs ATCO Electric to provide the distribution and transmission function allocations for each of its building projects in future capital tracker true-up applications. Paragraph 58

Appendix 4 – Table of compliance with previous Commission directions

Decision reference	Commission direction	ATCO Electric's response and application reference
Decision 3218-D01-2015, paragraph 482	The Commission directed that in future capital tracker applications, ATCO Electric is to provide a breakdown of its capital tracker income tax calculations into their component parts (return, interest, depreciation, capital costs allowance, capitalized pension, ES&G and removal and abandonment costs). In addition, in future capital tracker applications, the Commission directed ATCO Electric to provide supporting calculations for any income tax components that were assigned to capital projects or programs using an allocation methodology, and provide an explanation of how the total amounts to be allocated were calculated.	The same income tax methodology that was used in ATCO Electric's 2013-2015 capital tracker compliance filing, Proceeding 20369, was used in this application. Section 4 Appendix A, schedules 6-2, 6- 3, 6-4, 7-2, 7-3, 7-4, 8-2, 8-3, 8- 4, 9-2, 9-3 and 9-4
Decision 3218-D01-2015, paragraph 502	The Commission directed that in subsequent capital tracker true-up applications, ATCO Electric is to address whether the driver for any of the previously approved forecast projects or programs has changed. In the event that the driver of a project or program has changed since the forecast project or program was approved, the Commission directed ATCO Electric to identify these projects and programs and provide evidentiary support that each project or program continues to satisfy the requirements of Criterion 2.	ATCO Electric confirmed that the driver for previously approved forecast programs or projects has not changed. Section 3.1
Decision 3218-D01-2015, paragraph 503	The Commission directed ATCO Electric to provide evidence with respect to how the denied IT capital tracker satisfies the requirements of Criterion 2, if it chooses to apply for capital tracker treatment for the IT-related costs in its next capital tracker application.	ATCO Electric did not reapply for capital tracker treatment of the IT costs previously ruled ineligible for capital tracker treatment.
Decision 3218-D01-2015, paragraph 520	The Commission directed ATCO Electric to describe fully its formal project management policies and procedures in its next capital tracker application.	Section 3

Decision reference	Commission direction	ATCO Electric's response and application reference
Decision 3218-D01-2015, paragraph 531	The Commission considered that ATCO Electric should reduce its reliance upon hard-coded numbers in its spreadsheets and, when it is necessary to use a hard-coded number, provide a full explanation as to why the use of a hard-coded number was necessary and provide direct assurances that a number is accurate.	ATCO Electric's spreadsheets set out all elements of the accounting test in Excel format, with linked and working formulas. Appendix A – Project Net Cost Schedules
Decision 3218-D01-2015, paragraph 555	The Commission directed ATCO Electric, in future capital tracker applications, to provide and support its overhead costs in a similar manner to the information contained in ATCO Electric's IR responses and rebuttal evidence filed in Proceeding 3218, and be prepared to explain any significant year-over-year changes in the items that make up the overhead pool. To the extent that a company limits the year-over-year increases to an item in the overhead pool to I-X, the Commission considers that to be a reasonable approach for capital tracker purposes. However, the company is not required to limit its increases to its overhead items to I-X if it can demonstrate that an increase in excess of this amount, is prudent.	Section 3.6
Decision 3218-D01-2015, paragraph 562	The Commission directed ATCO Electric to provide evidence in future capital tracker applications on the effect, if any, of the separation of its distribution and transmission functions on the applied-for capital trackers, and where there is an effect on the applied-for capital trackers, ATCO Electric shall provide an explanation and quantification of the effect.	In Proceeding 3218, ATCO Electric confirmed that the Transmission and Distribution split had minimal impact on the capital trackers. ATCO Electric confirmed that this remains the case for the current application.
Decision 3558-D01-2015, Appendix 3 1. Schedules and related evidence	In addition to the materials required pursuant to paragraph 1091 of Decision 2013-435, a company must include in each capital tracker true-up application and in each capital tracker forecast application a set of Microsoft Excel® schedules setting out all the elements of the accounting test, materiality test and the resulting K factor calculation as directed in Decision 2013-435. a. The schedules provided must demonstrate that the revenue generated under the I-X mechanism for each capital tracker project or program are not covered by the actual or forecast revenue	Appendix A – Project Net Cost Schedules Section 4 ATCO Electric provided the accounting test that demonstrates that the revenue generated under the I-X mechanism does not cover the revenue requirement associated with the capital program. Appendix A included both capital tracker and non-tracker capital programs. The schedules set out all

Decision reference	Commission direction	ATCO Electric's response and application reference
	requirement associated with that capital project or program. b. The schedules provided must list each capital project and program, both capital tracker projects and programs and non-capital capital projects and programs with actual or forecast capital additions in the year. The schedules must also demonstrate, in Excel format with linked and working formulas, that the amounts of depreciation, overheads and income tax allocated to each capital tracker and noncapital tracker project or program, reconciled to the total amount for all projects or programs. c. Evidence that the capital cost allowance amounts have been reconciled with the amounts filed with the Canada Revenue Agency.	elements of the accounting test in Excel format, with linked and working formulas. Appendix A - Schedule 6-4 provided the capital cost allowance amounts that have been reconciled with the amounts filed with the CRA.
Decision 3558-D01-2015, Appendix 3 2. Capital tracker projects or programs	a. The rationale for the project, including the nature, scope, location, timing and cost of the project. (To the extent the scope and nature of an approved on-going multi-year project remain significantly unchanged year-over-year, this information is not required.) b. A summary of the services provided by an affiliate, the amounts paid and identification of how those amounts were determined. c. Any context for the project, which may include related past, present and future plans (e.g., for multi-year capital expenditures). d. Evidence demonstrating that in the absence of the proposed capital expenditures, deterioration in service quality and safety would result. e. Qualitative and, to the extent possible, quantitative descriptions of the service quality and safety risks addressed by the project. f. Evidence that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program. g. A discussion of any reasonable alternatives, including the rationale for recommending the proposed solution. h. A detailed forecast of costs for the project or project components, in sufficient	Preamble to each capital tracker program. Appendix A attached to each business case and project update.

Decision reference	Commission direction	ATCO Electric's response and application reference
	detail to allow an evaluation of the reasonableness of the forecast. i. A comparison of actual expenditures to forecast expenditures on similar projects over at least the previous five years, if available, including an explanation of any differences. j. With respect to proposed capital trackers, an explanation of any differences between the forecast costs of projects proposed for capital tracker treatment and the actual or updated forecast costs of similar projects undertaken in the prior year. This explanation should provide a breakdown of the project costs that includes both units and costs per-unit on a forecast and actual or updated forecast basis. k. With respect to the true-up of capital tracker projects, an explanation of any differences between the forecast costs of projects approved for capital tracker treatment and the actual cost of these projects undertaken in the prior year. This explanation should provide a breakdown of the project costs that includes both units and costs-per unit on a forecast and actual basis.	
Decision 3558-D01-2015, Appendix 3 3. Non-Capital tracker projects or programs	a. Project descriptions of all non-capital tracker projects and programs with actual or forecast capital additions in the year, that adequately describe, for the purpose of understanding project or program groupings, the nature and purpose of the proposed project or program.	Appendix G
Decision 3434-D01-2015, paragraph 70	The Commission directed the companies to update the ROE and capital structure used in the second component of the accounting test to reflect the approved values resulting from the Proceeding 2191. Furthermore, the Commission considered that in the second component of the accounting test, it is necessary to update the ROE to incorporate the most recently approved ROE, and those values will continue to be updated in future GCOC proceedings. Similar to the ROE, the Commission considered that the capital structure also should be revised in the second component of the accounting test to	ATCO Electric acknowledged that the Commission has initiated the 2016 generic cost of capital, Proceeding 20371, and that its applied for 2016 and 2017 K factors will remain interim until the ROE and capital structure have been finalized by the Commission for the year in question.

Decision reference	Commission direction	ATCO Electric's response and application reference
	match decisions made in future GCOC proceedings. To the extent there is a time lag between when capital tracker decisions are released and when the decisions on future GCOC proceedings for the same year are released, similar to the current situation, where the Commission has issued some decisions on 2013 capital tracker true-up applications but the ROE and capital structure for 2013 have not yet be finalized in the decision in Proceeding 2191, all capital tracker amounts will remain interim until the ROE and capital structure have been finalized by the Commission for the year in question.	
Decision 3434-D01-2015, paragraph 76	The Commission directed the companies in their 2016 and 2017 capital tracker applications to use their forecast cost of embedded debt and preferred shares, if applicable, when calculating the revenue requirement associated with a proposed capital tracker.	ATCO Electric forecast debt issuances for 2016 and 2017 are based on the rate that resulted from the company's most recent (2014 actual) debt issuance. Section 4.2 Appendix H
Decision 3434-D01-2015, paragraph 89	The Commission directed the companies to use their forecast cost of embedded debt in calculating the forecast revenue requirement associated with a proposed capital tracker in the second component of the accounting test, to reflect the correct funding requirements associated with expenditures made on capital tracker projects. Similarly, the Commission found that the forecast cost of embedded debt should be trued-up to the actual cost of embedded debt incurred by the utility in the year for which the capital tracker was approved. The Commission agreed with Calgary that the embedded debt rate used in the second component of the accounting test in the true-up process should match the rate that appears on the company's Rule 005 filing from the associated year, and if it does not match, the Commission directed the company to provide an explanation of why it does not match, in its capital tracker true-up application.	ATCO Electric updated the WACC rates to include its actual/forecast embedded cost of debt rates, as well as the approved ROE of 8.3 per cent and the approved equity thickness of 38 per cent. Schedule 2.3-D in ATCO Electric's 2014 Rule 005 Filing. Section 4.2
Decision 3434-D01-2015, paragraph 92	The Commission directed that in capital tracker true-up applications, for the second component of the accounting test, a	ATCO Electric updated the WACC rates to include its actual/forecast embedded cost of

Decision reference	Commission direction	ATCO Electric's response and application reference
	company's WACC will reflect the company's current embedded debt rate based on its actual debt issues, and will use the ROE and capital structure for the year, as approved in the most recent Commission decision establishing the deemed ROE and capital structure for the company.	debt rates, as well as the approved ROE of 8.3 per cent and the approved equity thickness of 38 per cent. The 2014 actual embedded cost of debt rate used can be referenced to ATCO Electric's 2014 Rule 005 Filing.



IN THE MATTER OF

BRITISH COLUMBIA UTILITIES COMMISSION

GENERIC COST OF CAPITAL PROCEEDING (STAGE 1)

DECISION

May 10, 2013

Before:

**D.A. Cote, Commissioner/Panel Chair
R. Giammarino, Commissioner
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner**

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EXECUTIVE SUMMARY

By Order G-20-12 on February 28, 2012, the British Columbia Utilities Commission (Commission) initiated the Generic Cost of Capital (GCOC) proceeding pursuant to section 82 of the *Utilities Commission Act* to review and determine among other things, the following:

- The setting of the appropriate cost of capital for a benchmark low-risk utility;
- The possible return to an automatic adjustment mechanism (AAM) for setting the return on equity (ROE) for the benchmark utility each year; and
- The establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt.

By Order G-48-12 on October 11, 2012, the Commission established the following:

- The proceeding will have two stages; Stage 1 will determine the cost of capital for the benchmark utility and Stage 2 will establish the cost of capital for other utilities as compared to the benchmark.
- Fortis Energy Inc. (FEI) in its pre-amalgamation state will serve as the benchmark utility for the GCOC proceeding; and
- An oral public hearing commencing on December 12, 2012, will be held to determine the cost of capital for the benchmark utility.

Fair Return Standard

The Fair Return Standard is foundational for cost of capital proceedings and has three requirements for a fair and reasonable return on capital: the comparable investment requirement, the financial integrity requirement, and the capital attraction requirement. The Commission Panel, consistent with previous decisions and the regulatory compact, confirms that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. In the current proceeding, the Commission Panel has not considered the rate impacts of the revenue required to yield the fair return but has noted that by seeking an optimal capital structure and the opportunity cost of capital, the needs of customers are being served.

Contextual Issues

Three important issues were raised that were contextual in nature; the significance of past cost of capital decisions, the significance of decisions from other jurisdictions and the relevance of the disparity between “allowed” and “actual” ROE.

With respect to past cost of capital decisions and appropriate points of reference, the Commission Panel accepts that the 2009 Decision is a reasonable point of reference with respect to long-term risk as this is the most recent proceeding and has been used extensively by the parties. The Panel also remains open to looking back to the 2006 ROE Decision where appropriate.

With respect to reliance upon data from US jurisdictions, the Commission Panel has determined that it is appropriate to continue to accept the use of historical and forecast data but do not accept that US data should be considered to be the same or be given equal weight as data for Canadian utilities. Concerning Canadian jurisdictional decisions, the Panel acknowledges the importance of considering methodologies, approaches, and regulatory principles related to other jurisdictions’ decisions but does not accept the use of results and values for the purpose of calibration.

Concerning the relevance of disparity between FEI’s “allowed” and “actual” ROE, the Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from FEI’s positive track record. However, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management’s proactive approach. Additionally, the Panel is of the view that these differences are assessed in revenue requirement proceedings.

Capital Structure

In determining an appropriate capital structure for the benchmark utility, the Commission Panel considered FEI’s long and short-term risk, development of an optimal capital structure, credit ratings and metrics and experiences of other jurisdictions.

The Commission Panel is supportive of maintaining an “A” category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard. The Commission Panel finds that reductions in long-term risk are warranted with respect to provincial climate and energy policies as well as the competitive position of natural gas relative to electricity. While acknowledging that there has been little change in short-term risk since the 2009 Decision, the Panel has determined that only minimal weight can be given to short-term risk as an impediment to earning a fair return. In consideration of both long and short-term risks, the Commission Panel has determined that a reduction in common equity ratio of 1.5 percent to 38.5 percent is appropriate. The Commission Panel considers a 38.5 percent common equity ratio reflects the reduced long-term risk, yet balances this against potential disruption caused by a significant weakening of credit metrics. The awarded common equity ratio falls within the upper end of the range of comparative utilities in other Canadian jurisdictions.

Return on Equity

The Commission Panel considered expert evidence on various model approaches to determine ROE. The Panel finds that the discounted cash flow model and the capital asset pricing model should be given equal weight in determining the ROE of the benchmark utility. No weight was given to the equity risk premium and comparative earnings models. The Commission has determined that an ROE of 8.75 percent inclusive of a 0.50 percent allowance for financial flexibility is appropriate for the benchmark utility. The benchmark utility ROE will be effective January 1, 2013 and will be effective until December 31, 2015, subject to updating as a result applying the AAM formula.

Automatic Adjustment Formula

Consideration was given to re-instituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings, which had been eliminated in the 2009 Decision. In addition, consideration was given to the status of AAMs in other jurisdictions and what optional AAMs might be considered. The Commission Panel has determined that it is appropriate to re-establish an AAM formula noting that it better meets the FRS than giving no consideration to the market changes over the period between ROE proceedings. The Panel has directed that a two variable model considering changes to utility bond spreads and the long-term Canada bond yield be

established to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. Implementation of the AAM will be subject to an actual Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula will not be in effect as long as the long Canada bond yield is below 3.8 percent.

Cost of Capital – Small Utilities

Stage 1 of the GCOC proceeding considered the cost of capital for the benchmark utility, FEI. Stage 2 will assess the differences in short and long-term risk faced by regulated utilities in British Columbia other than FEI and their impact on the capital structure and ROE for these utilities. The Commission Panel has recommended that the utilities be separated into three groups, each of which will be handled separately. The Commission Panel has also made a number of determinations and findings with respect to the handling of the size factor as a business risk and deemed short and long-term debt interest rates.

1.0 INTRODUCTION

1.1 Background

The 2009 ROE Decision¹ (2009 Decision) was issued concurrently with Order G-158-09 on December 16, 2009. The Order set the return on equity for FEI, the benchmark utility in British Columbia, at 9.5 percent effective July 1, 2009, and the equity ratio at 40 percent effective January 1, 2010. Order G-158-09 also eliminated the AAM, which had been utilized to set the ROE for the benchmark utility annually. Since that Order, there have been no further adjustments to the ROE or capital structure of the benchmark utility.

This Decision for Stage 1 of the Generic Cost of Capital (GCOC) proceeding sets out:

- the new approved ROE and capital structure for FEI;
- the new automatic adjustment formula and the conditions under which it will be in effect; and
- the framework to review the cost of capital for small utilities.

Stating that changes have occurred in the financial markets since the 2009 Decision, the Commission, by Order G-20-12 dated February 28, 2012, initiated the GCOC proceeding pursuant to section 82 of the *Utilities Commission Act (UCA)* to review and determine, among other things, the following:

- the ROE and capital structure for a benchmark low-risk utility;
- the possible return to an AAM to set the ROE for the benchmark utility each year; and
- a deemed capital structure and deemed ROE for small utilities, particularly those utilities without short-term debt.

Order G-20-12 established that all public utilities would be considered applicants in the GCOC proceeding and included a preliminary scoping document, which set out a list of matters to be examined and determined within the proceeding. The Order further divided the list of utilities regulated by the BCUC into Affected Utilities and Other Utilities. The Affected Utilities have been so designated given their active participation in previous ROE proceedings or their anticipated interest

¹ In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and capital Structure Decision, December 16, 2009.

in the GCOC proceeding as investor-owned utilities. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. The Other Utilities are so designated as they have not actively participated in previous ROE proceedings and they were not expected to file evidence in the GCOC proceeding.

On April 18, 2012, the Commission, by Order G-47-12, issued a final scoping document, which set out the purpose and scope of the proceeding. On April 19, 2012, the Commission issued a preliminary draft of the minimum filing requirements. Following submissions by Registered Interveners, the Commission issued Order G-72-12 on June 1, 2012, which set out the minimum filing requirements for those utilities expected to participate and a preliminary regulatory timetable. In an attachment to Appendix A to the Order, the Commission also placed on the record the terms of reference for a Survey of Cost of Capital Practices in Canada prepared by the Commission consultant, the Brattle Group (Brattle Report).

On October 11, 2012, following a procedural conference held on October 4, 2012, the Commission by Order G-148-12 established that in 2012, FEI in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding. The Order also established an oral public hearing to commence on December 12, 2012, to hear the cost of capital for the benchmark utility. In addition, it was determined that the proceeding will have two stages: Stage 1 establishing the ROE and capital structure for FEI the benchmark utility, and Stage 2, establishing a cost of capital for other utilities as compared to the benchmark utility.

1.2 Purpose and Scope of the Generic Cost of Capital Proceeding

The Commission determined the purpose and scope of the GCOC proceeding in Order G-47-12, with certain outstanding matters such as the appropriate utility, which would serve as the benchmark utility, determined by Order G-148-12 dated October 11, 2012. The purpose and scope of this proceeding are as follows:

PURPOSE OF THE PROCEEDING

The main purposes of the GCOC Proceeding are:

- I. to establish a method to determine the appropriate cost of capital for a benchmark low-risk utility in British Columbia, commencing January 1, 2013, and to establish how the Benchmark return on equity (ROE) will be reviewed, and if required, adjusted on a regular basis;
- II. to establish a generic methodology or process on how to establish each utility's cost of capital based on the cost of capital for a benchmark low-risk utility; and
- III. to establish a framework for determining the appropriate cost of capital for other smaller utilities in the province.

SCOPE OF THE PROCEEDING

- I. The appropriate cost of capital for a benchmark low-risk utility effective January 1, 2013. Cost of capital includes capital structure, return on common equity, and interest on debt.
- II. Establishment of a Benchmark ROE based on a benchmark low-risk utility effective January 1, 2013 to December 31, 2013 for the initial transition year.
- III. Whether re-establishment of an ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is accepted as a result of the GCOC Proceeding, it would be implemented January 1, 2014. If not, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013 on a regular basis.
- IV. A generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility.
- V. In certain circumstances, a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt. This would involve setting a methodology on how to calculate a deemed interest rate.
- VI. In certain circumstances for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM). If warranted, the Interest AAM would be implemented for January 1, 2014. If not warranted, setting a future regulatory process on how the deemed interest for a benchmark low-risk utility would be adjusted in future years beyond December 31, 2013.

1.3 Regulatory Process

As noted previously, the Commission retained The Brattle Group to prepare a survey report on the Cost of Capital Practices in Canada. The Brattle Report, filed as Exhibit A2-3 on June 8, 2012, provides a description of the cost of capital estimation methods and the common approaches in implementing the results in Canadian jurisdictions. The Brattle Report was intended to provide context and background for the establishment of the cost of capital of a low-risk benchmark utility

in B.C. All parties were provided with the opportunity to file Information Requests (IRs) on the Report.

In accordance with Order G-72-12, the following utilities filed minimum filing requirements:

- FEI, FortisBC Inc. , FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC (Whistler) Inc. (FEW),[collectively (FBCU)];
- Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. [collectively (PNG)]; and
- Corix Utilities (Corix).

The Industrial Customers Group of FortisBC Inc. (ICG) and the BC Utility Customers comprising the Association of Major Power Customers of BC (AMPC), the British Columbia Pensioners' and Seniors' Organization (BCPSO), and the Commercial Energy Consumers of BC (CEC) were active in the proceeding. Two rounds of IRs with respect to evidence filed by Affected Utilities and one round of IRs on evidence filed by Interveners took place.

The oral public hearing, including an *in camera* session on FBCU's confidential reports, took place over a period of seven days between December 12, 2012 and December 21, 2012. FBCU tendered five witness panels for cross-examination and Corix, BC Utility Customers, and the ICG each had one witness panel for cross-examination.

A list of procedural orders in the GCOC proceeding is included in Appendix A. A list of Appearances is included in Appendix B and Appendix C contains a list of witness panels that gave evidence. Appendix D contains the List of Exhibits. Appendix E contains a risk matrix used in a recent Commission decision with respect to a small utility that is Appendix B to Order C-1-13, Appendix F contains summary tables of ROE estimates by expert witnesses retained by the utilities and ratepayer groups, and. Appendix G is a list of acronyms.

1.4 Approach to Decision

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

There are a number of broader issues of importance, which were raised by this proceeding. These are contextual in nature and include the following:

- importance of past cost of capital decisions;
- consideration of decisions from other jurisdictions; and
- the relevance of the disparity between “allowed” and “actual” ROE.

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

Section 4 deals with an appropriate capital structure given FEI’s level of risk with consideration of credit ratings and metrics and decisions in other jurisdictions. Section 5 considers the appropriate ROE for the benchmark utility with a review of some of the key issues and models employed by the expert witnesses. Section 6 examines potential AAM models and whether there is justification to return to a reliance on such a mechanism. Section 7 considers issues related to cost of capital for small utilities, and Section 8 examines the need for financial models presented in proceedings such as this to have a sound theoretical basis.

2.0 LEGISLATIVE FRAMEWORK – THE FAIR RETURN STANDARD

2.1 Legislative Requirement

The enabling legislation for the BCUC, the *UCA*, provides that a public utility must not make, demand or receive:

- (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia;
- (b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

A rate is “unjust” or “unreasonable” if it is:

- (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;
- (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or
- (c) unjust and unreasonable for any other reason.²

The *UCA*, and other Canadian legislation delegating power to regulatory tribunals, follow what is known as the “Regulatory Compact.” In general terms, the Regulatory Compact states that in exchange for an exclusive franchise to serve a defined area:

- a regulated utility must provide safe, reliable, non-discriminatory service to its ratepayers at cost-based rates as prescribed by the regulatory tribunal, and
- the regulatory tribunal must allow the regulated utility an opportunity to earn a fair return on its invested capital.

(Exhibit C4-9, p. 7; BCPSO Final Submission, p. 3)

The approach to determining a fair return on the cost of invested capital in a regulated utility has normally been referred to as the Fair Return Standard (FRS).

² *UCA* sections 59 (1) (a) (b), 59(5), 60 (1) (a) (b) (i)

2.2 Elements of a Fair Return Standard

The Supreme Court of Canada decision in *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186, (*Northwestern Utilities*) at pages 192-193 describes the FRS as follows:

“The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, (which will be net to the company,) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company’s enterprise.” (per Lamont J.)

The Brattle Report notes that the legal decisions, which provide the overarching principles of the FRS, do not prescribe how to determine comparability, how to estimate the cost of capital for the comparable companies, or how to apply those estimates when setting allowable rates. The cost of capital is the expected rate of return in capital markets on alternative investments of equivalent risk. The expected rate of return investors require is based on the risk-return alternatives available in competitive capital markets. In other words, the cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. (Exhibit A2-3, pp. 2-3)

On page 8 in the 2009 Decision, the Commission endorsed the National Energy Board’s (NEB) articulation of the Fair Return Standard in NEB Decision RH-1-2008 where NEB stated:

“The Fair Return Standard requires that a fair or reasonable overall return on capital should:

- Be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
- Enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement).”

Ms. McShane, the expert witness for FBCU, submitted that the standards for a fair return arise from legal precedents and there are three requirements the utility must:

1. Earn a return on investment commensurate with that of comparable risk enterprises;
2. Maintain its financial integrity; and
3. Attract capital on reasonable terms.

According to Ms. McShane, the legal precedents make it clear that the three requirements are separate and distinct. The FRS is met only if all three requirements are satisfied. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8)

Dr. Laurence Booth, the expert witness for the BC Utility Customers, submitted that the definition of a fair rate of return was confirmed in *BC Electric [Railway Co. Ltd. v. Public Utilities Commission of B.C. et al]* ([1960] S.C.R. 837)] when Mr. Justice Lamont adopted the definition of a fair rate of return, put forward in *Northwestern Utilities*.

Dr. Booth submitted that the definition in the *Northwestern Utilities* is referred to as an opportunity cost, in that the fair return is what could be earned by investing in similar securities elsewhere. Only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair, i.e., they will neither reward the owners with excessive profits, nor ratepayers by charging prices below cost. Dr. Booth further submitted that to any modern financial economist, Mr. Justice Lamont's definition of a fair rate of return as an opportunity cost means a risk adjusted discount rate or expected rate of return. (Exhibit C6-12, pp. 7, 8)

2.3 Application of the Fair Return Standard

The Commission Panel observes that the application of the FRS leaves room for disagreement, judgment and discretion. The methods relied upon by various regulators and practitioners therefore differ substantially. For example, while some regulators set rates by determining the weighted-average cost of debt and equity that the regulated company should be allowed to earn on its invested capital (as a whole), others determine separately the cost of equity and possibly the percentage of equity that should be allowed in the regulated company's capital structure. (Exhibit A2-3, p. 2)

The Panel also notes the words of the Alberta Utilities Commission (AUC) on this subject related to conflicting evidence and applying judgment:

“....the determination of a fair return on equity for Alberta utilities requires the assessment of three criteria: return on comparable investments, ability to attract capital and maintenance of financial integrity. As noted by Mr. Justice Rothstein in the TransCanada Pipelines decision cited above, the determination of the rate of return on equity for a regulated utility is difficult given that the correct answer is not readily apparent. This determination requires an expert tribunal to apply its judgment in assessing often conflicting evidence and to consider the differing interests and perspectives on risk of debt and equity investors. This exercise is even more complex in Canada, and in Alberta in particular, given the limited number of stand-alone utilities issuing debt and the lack of any utilities that issue equity directly to investors.”³

The Commission Panel further notes the words of the Federal Court of Appeal’s ruling in *TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149* on just and reasonable tolls. It quotes the *Northwestern Utilities* and states:

“Tolls which reflect a fair return on capital will be just and reasonable to both the Mainline and its users.

It further states:

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

(*TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149, para. 33, 34*)

³ AUC 2009 Generic Cost of Capital Decision, November 12, 2009, p. 28

Submissions by Parties

None of the parties disagree with the Fair Return Standard as the applicable test. The Utilities and Interveners, however, disagree on how this test should be applied.

FBCU take the position that the overall rate of return allowed for FEI must be based on the utility's true cost of capital without compromising the legitimate cost of service to achieve lower rates in the short-run. FBCU submit that the combination of allowed ROE and capital structure should permit FEI to maintain credit ratings that are at a minimum in the "A" credit category in varying market conditions. This matter is further addressed in Section 4.5.

FBCU argue that a fair return is not synonymous with the lowest possible return. It pointed out that in the 2006 ROE Decision (2006 Decision),⁴ the Commission had articulated that the "lowest possible" was not the appropriate test. Therefore, FBCU submit that the Commission should not rely on evidence on rate impacts and that the view of Dr. Safir, ICG's expert witness, that the outcome of a "fair return" should always favour the lower range is fundamentally inconsistent with the authorities on the FRS. (FBCU Final Submission, pp. 1, 7, 11-12)

The AMPC/CEC do not dispute the definition of the FRS based on the NEB Decision RH-1-2008 and endorsed by the Commission in the 2009 Decision. However, the AMPC/CEC disagree with FBCU's submission that the three requirements listed are the only factors to be considered when deciding what constitutes a fair return, with no consideration of the Commission's broader mandate to balance the interest of customers and regulated utilities. AMPC/CEC submit that when acting as the surrogate for competition, the Commission cannot and must not protect FEI from all business and financial risk by unnecessarily raising the ROE and common equity at the expense of customers; and the Commission must scrutinize whether the cushion FEI asks for is truly necessary to meet the FRS in light of its broader mandate to protect consumers. In Section 4.5 of this Decision, the Commission Panel discusses the application of the FRS and the role of credit metrics in the implementation of the FRS requirements.

⁴ In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism Decision and Order G-14-06, March 2, 2006.

According to AMPC/CEC, Dr. Booth's evidence shows that he recommended a fair return by applying the principle in the FRS that "only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair." In addition, AMPC/CEC state that among other things, Dr. Booth checked his findings against numerous independent, reputable sources which confirmed that his estimates were reasonable. (AMPC/CEC Final Submission, pp. 5-7)

The BCPSO agrees with FBCU's characterization of the FRS and agrees that utilities are entitled to a competitive return as defined in the FRS' three tests regardless of the rate impact. However, BCPSO submits that it is not the same as to say that customer interests carry no weight in setting an appropriate deemed cost of capital as utility customers have an interest in ensuring that the utility's cost of capital is not overstated. BCPSO submit that a fair return is one that takes into account the right of utility customers to pay no more than a fair and reasonable charge for the service provided. Based on its logic, BCPSO submits that the evidence from Exhibit B1-42 which compares the rate impact of a 5 percent change in the equity ratio to a 50 and 100 basis point change in ROE is admissible; and furthermore, if the utility can be provided a competitive return with less rate impact, that option should be chosen. (BCPSO Final Submission, pp. 3-5)

ICG submits that the interests of customers should be paramount to those of the shareholders and reiterates Dr. Safir's testimony that where a range of competitive returns is available for evaluation, the outcome of a "fair return" should always favour the lower range presented. (ICG Final Submission, p. 3)

In Reply, FBCU submit that the Commission would err in accepting ICG's argument that regulation is simply to benefit customers. FBCU submitted that the Commission, in the 2009 Decision, had been explicit that it was not accounting for rate impacts in reaching its decision. (FBCU Reply, pp. 2-3)

Commission Determination

In previous decisions, the Commission concluded that the opportunity to earn a fair return must be provided to each regulated utility as a separate obligation from those service and financing requirements detailed in other sections of the *UCA*. For instance, on page 8 of its 2006 ROE Decision, the Commission said:

“In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital.”

The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility. This Decision reiterates the principle articulated in the 2006 ROE Decision and the 2009 Decision, and argued by FBCU on pages 7 to 9 in its Final Submission, that the Commission does not consider the rate impacts of the revenue required to yield the fair return. However, by seeking an optimal capital structure and the opportunity cost of capital we are serving the needs of the customer.

While this Commission Panel has not considered the rate impacts of the revenue required to yield the fair return *per se*, we are of the view that the capital structure of the utility should be set efficiently and, therefore, there is value in finding an optimal capital structure. Exhibit B1-42 provides comparative information on revenue requirements for FEI based on either a change in equity thickness or a change in ROE. The ICG submits that the Commission should reduce the ROE before reducing the capital structure of FEI. (ICG Final Submission, p. 4) In this regard, the Commission Panel finds the information on rate impacts as presented in Exhibit B1-42 useful. An optimal capital structure is discussed further in Section 4.4.

3.0 CONTEXTUAL ISSUES

This section considers important issues raised by this proceeding that are contextual in nature; they include:

- The significance of past cost of capital decisions;
- The relevance of US data and the significance of decisions from other jurisdictions; and
- The relevance of the disparity between “allowed” and “actual” ROE.

3.1 Past Cost of Capital Decisions

An important issue arising within the 2012 GCOC proceeding is whether a previous cost of capital decision is an appropriate reference point against which evidence in the current proceeding can be compared. Specifically, the questions facing the Commission Panel are: (1) whether a reference point is required, and (2) in the event it is, what reference point would be most appropriate and to what extent should it be relied upon in the Commission Panel’s decision - making process. Within this proceeding, the primary comparative reference point has been the 2009 Decision, which has been relied on to illustrate changes in capital markets as well as changes in short and long-term risk since that time. Each of these referenced areas will be discussed in turn.

Submissions by Parties

3.1.1 Changes in Capital Markets

Throughout this proceeding, the FBCU have relied upon and underlined the Commission’s statement that changes have occurred in capital markets since the 2009 Decision was issued. They have taken the position that capital markets are similar (albeit for different reasons) to what they were in the fall of 2009 when the previous cost of capital proceeding took place. The FBCU have relied very heavily on the 2009 Decision as a reference point for the current proceeding and have provided comparisons between what they believe exists today as opposed to conditions which existed at the time of the 2009 Decision. FBCU have relied upon the opinion evidence prepared by two of their expert witnesses, Ms. McShane and Mr. Engen, which showed that many of the key indicators of conditions within capital markets are similar and in some cases worse than the same indicators reflecting capital markets late in 2009. FBCU maintain that the experts along with market indicators

and Bank of Canada published information all suggest that equity capital markets in Canada are challenging and volatile and the market cost of equity has risen since 2009. In summary, FBCU maintain that current market conditions provide no basis for reducing FEI's overall return as argued by interveners. (FBCU Final Submission, pp. 1-2, 16-30)

ICG takes issue with FBCU on their choice of 2009 as an appropriate reference point and argue that a more appropriate reference point was the 2006 Decision. ICG submits that the 2009 Decision did not appropriately balance the interests of customers and shareholders and gave inappropriate weight to the interests of shareholders. Moreover, ICG submits that the 2009 Decision represented a significant departure from previous Commission cost of capital decisions. With respect to its Canadian peers, ICG points out that the weighted equity return component was materially lower (by 0.47) in 2005 through 2009 and materially higher (by 0.57) in the 2010 to 2012 period. ICG argues that the 2009 Decision should not be a point of reference for this decision given a steady decline in FEI's business risks since 2005. (ICG Final Submission, pp. 11-12)

BCPSO also takes issue with the use of the 2009 Decision as a reference point for this decision, expressing concern as to whether the capital market conditions comparator dates are consistent across the two proceedings. BCPSO submits that the current proceeding is forward looking with respect to capital conditions and snapshot-style evidence of past capital conditions is of limited value. In its view, the economic tests such as equity risk premium (ERP), comparable earnings (CE) and discounted cash flow (DCF) provide a better basis in assessing cost of capital stating that they "are more precise, forward looking, and can be made industry or company specific." The primary value of evidence relating to general market conditions lies in the trends it demonstrates. (BCPSO Final Submission, p. 6)

AMPC/CEC submit that regulators do not base a cost of capital decision on immediate circumstances only. They assert that the Commission will consider economic and financial conditions occurring since the last hearing and will also consider the outlook on a going forward basis. Referring to Mr. Engen's S&P/TSX Composite Index 10 Year Performance data, AMPC/CEC state that the difference now "is that the last few years have witnessed the market hold or increase ground it recovered, whereas in the lead up to the 2009 hearing, it had just suffered a dramatic crash." They further point out the FBCU argument that capital markets are similar to what they were in 2009 is in conflict

with their own witnesses' (Ms. McShane and Dr. Vander Weide) DCF calculations, which have declined considerably since the close of evidence in the last hearing. (AMPC/CEC Final Submission, pp. 28-29; Exhibit B-1-9-6, FBCU Evidence, p. 14, updated in Exhibit B-1-49)

In Reply to ICG, the FBCU state that the choice of 2009 as a point of comparison is because that proceeding is where the Commission most recently assessed FEI's business risk. To disregard this in favour of the 2006 Decision because ICG preferred the outcome in FBCU's view is indefensible. (FBCU Reply, p. 21)

Concerning the AMPC/CEC's submissions regarding the inconsistency in capital markets being similar to 2009 and FBCU's witnesses' DCF calculations, the FBCU state the following:

- Mr. Engen's evidence relates to the overall capital market and trends in the market cost of equity which indicate the market cost of equity is higher today.
- Ms. McShane's and Dr. Vander Weide's DCF calculations relate to a narrow segment of the overall market and deal specifically with FEI's cost of equity. (FBCU Reply, p. 5)

3.1.2 Changes in Long-Term Risk

While there has been considerable disagreement with respect to relying upon 2009 capital markets as a reference point for comparison, there has been little concern raised by the parties with respect to using the 2009 Decision as a reference for changes in long-term risk. Both the FBCU and interveners have relied heavily on what has changed since 2009 and in some cases referred back to the period prior to the 2006 Decision as a source of comparison.

Commission Discussion

The Commission Panel accepts that many of the indicators reflecting the current state of the capital markets are similar to what they were in 2009. This, however, does not mean that the conditions under which the 2009 Decision was made are the same as they are today. As noted in Mr. Engen's evidence, the current period is characterized by concerns for a sustained US economic recovery, fears of an economic slowdown related to weak economic data from the US and the European Union and the European sovereign debt crisis, among other things. These are not at all descriptive

of the period in latter 2009. (Exhibit B1-9-6, Appendix E, Engen Evidence, pp. 7-8) Moreover, as pointed out by AMPC/CEC, since that time markets have demonstrated a degree of stabilization in sharp contrast to the situation preceding the 2009 Decision which followed a dramatic crash. Therefore, while there are some similarities between the current period and late 2009, the Panel is of the view there are significant differences. By contrast, the markets, while maintaining volatility, have experienced a few years of comparative stability and the investor has been distanced from the financial conditions characterizing the period leading to the 2009 proceeding.

The Commission Panel is mindful that many of the key indicators of capital market conditions are similar to those of 2009 but does not consider them alone to be determinative in reaching a decision on the cost of equity. While considering changes in capital markets, pricing models some of which reflect the market outlook, are very important in reaching a determination on the appropriate rate of return in this proceeding.

The Commission Panel does accept that the period leading up to the 2009 Decision is a reasonable point of comparison with respect to changes in long-term risk as this is the most recent proceeding and notes that this has been used extensively by the parties. However, the Panel remains open to looking back further to the 2006 Decision where appropriate. In the view of the Panel, a determination on the degree of change in long-term risk is a much more discrete process. It is dependent upon an assessment of the level of risk, which exists in the current circumstances as compared to those which existed at a previous point in time. Therefore, we consider the periods prior to both the 2009 Decision and the 2006 Decision as appropriate reference points in assessing the level of long-term risk faced by FEI.

The Commission Panel does not accept ICG's argument that the 2009 Decision fails to appropriately balance the interests of customers and shareholders. In the view of the Panel, there is no value in re-examining the 2009 Decision nor is there evidence to support the need for doing so.

3.2 Consideration of Other Jurisdictions

Throughout the evidentiary portion of this proceeding there has been considerable reliance among the parties upon data and cost of capital decisions from both US and Canadian jurisdictions. The Commission Panel considers these separately as the issues related to each differ.

3.2.1 Relevance of US Data and Decisions

In the 2006 Decision, two issues related to reliance upon US data in cost of capital proceedings were dealt with by the Commission:

- 1) Opportunities exist for investors to commit capital on a global basis. The Commission Panel noted that there was considerable foreign exchange risk and was not convinced that the Federal Government's easing of foreign content in retirement portfolios was sufficient reason to raise the equity return of a utility.
- 2) The necessity of looking beyond Canadian data in measuring the risk premium. The Commission accepted the use of historical and forecast data for US utilities "when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results." (2006 Decision, p. 50)

In the 2009 Decision, the Commission accepted the use of historical and forecast data of US utilities as outlined in the 2006 Decision. In addition, the Commission supported the need for utilities to compete in a global marketplace and reiterated its acceptance of the use of historical and forecasting data. In the 2009 Decision, the Commission also noted the lack of relevant Canadian data and considered the potential for US gas utilities to act as a proxy in the determination of cost of capital and credit metrics. (2009 ROE Decision, pp. 15-16)

Submissions by Parties

In the current proceeding, the FBCU take the position that the Commission should find that US data remains useful and that US utilities can be appropriate comparators based on total investment risk. In support of this, they rely on the evidence of Ms. McShane and Dr. Vander Weide who make the following assertions:

- The operating, regulatory and business environments for US and Canadian regulated companies are generally similar.
- Capital markets in Canada and the US are significantly integrated and the cost of capital environment is similar.

In further support of their argument, the FBCU note that Dr. Safir acknowledged the integration of capital markets in his evidence and utilized US companies in his Capital Asset Pricing Model (CAPM) and DCF analysis. Further, the FBCU argue that Dr. Booth, in spite of his concern with the use of US data, conceded there was a high degree of integration between US and Canadian markets. (FBCU Final Submission, pp. 96-97)

AMPC/CEC's witness Dr. Booth raised two concerns with the use of US data:

- US financial markets exhibit greater risk than Canadian markets and have generated higher premia in the past.
- Regulatory implementation differs even though US and Canadian principles of regulation are the same.

(Exhibit C6-12, Dr. Booth Evidence, Appendix B, p. 106)

AMPC/CEC submit that there is ample support for Dr. Booth's assertion that US markets are riskier than those in Canada. They point out his evidence demonstrates that over the period 1926-2011, US returns showed greater volatility than Canadian returns and the risk premium was higher in the US than the equivalent in Canada. They further submit that during Ms. McShane's cross-examination, she agreed that a typical US utility could be viewed as higher risk than a Canadian one and point out that her report aligns with Dr. Booth's as it presents a historical risk premium of 4.7-4.8 percent for Canada compared to 5.5-5.7 percent for the US. (AMPC Final Submission, p. 46) Concerning the difference between Canada and the US with respect to the implementation of regulatory principles, AMPC/CEC state that the Commission in the 2009 Decision was cognizant of the danger of relying on US comparables and cites the following statement of the Commission Panel in that decision:

"The Commission Panel agrees with Dr. Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short term, earn its allowed return than the Value Line US natural gas LDC enjoy." [emphasis added by AMPC/CEC]

Additionally, AMPC/CEC point to Dr. Booth's finding that Canadian utilities have higher bond ratings in spite of poorer financial ratios, which in his view reflects the importance bond rating agencies place on the differing regulatory approaches in Canada and the US. In summary, AMPC/CEC submit that the Commission should continue to approach US data based results with caution, adjusting them downward to reflect differences in financial and regulatory contexts between the two countries. (AMPC/CEC Final Submission, pp. 46-47)

FBCU argue that the evidence does not support a downward adjustment to US results and state the following:

"Since the financial crisis, long term interest rates have been similar in Canada and the US across a broad range of bond types, equity market volatility has been virtually identical, and market risk premium surveys show virtual identical values." (FBCU Reply, p. 28)

None of the parties have suggested that the Commission should put no weight on US data and decisions.

Commission Determination

The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. **Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.**

In making this determination the Commission Panel would like to be clear that while we accept there are similarities between the two jurisdictions, we do not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities. Canadian investors considering US utility investments are subject to currency exchange risk that would not be the case with Canadian utility investments. Additionally, the US regulatory

environment while similar is not identical to that of Canada. The 2009 Decision's reference to the array of deferral mechanisms resulting in greater certainty for the Canadian utility is just one example of potential differences between the jurisdictions. Moreover, Ms. McShane has acknowledged under cross-examination that the universe of US utilities is focused on vertically integrated utilities and, to the extent that there is a smaller number of Canadian investor-owned, vertically integrated utilities, the typical US utility could be viewed as higher risk than the typical Canadian utility. (T3:466-467) Therefore, in the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.

3.2.2 Consideration from other Canadian Jurisdictions

Throughout this proceeding the parties have chosen to utilize information and related decisions from other Canadian jurisdictions as support for the position they have taken on an issue. The Commission Panel notes that decisions in all jurisdictions result from the judgment of evidence specific to a region or a particular utility that in each case is unique. To the extent that the ROE and equity thickness of a specific utility in another jurisdiction can be used as a comparator, we are open to considering it if it helps inform our decision. However, considerable reliance on decisions from other jurisdictions in our view would lead to circularity that would ensure that only the status quo is maintained -- perhaps at the risk of common sense. The Commission Panel acknowledges the importance of considering the methodologies, approaches and regulatory principles related to other jurisdictions' decisions. However, we do not accept that it is appropriate for results and values to be used for the purpose of calibration in B.C.

3.3 **Relevance of Disparity between "Allowed" and "Actual ROE"**

3.3.1 Outline of the Issue

As described in Section 2.1, when setting a rate under the subsection 60 of *UCA*, the Commission must have due regard for, among other things, whether the rate is insufficient to yield fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property. This standard does not mean, however, that a utility must be guaranteed its allowed return on equity. It simply means that a utility must be given an opportunity to earn this return. In any particular year, the actual ROE earned may be below or above the

allowed ROE. The rates are set based on a forecast revenue requirement for the year, which includes a provision for the allowed ROE, grossed up for income taxes. The utility's actual performance during the fiscal year will determine how close the actual ROE will be to the allowed ROE.

Short-run risks in general relate to a utility's ability to annually earn its allowed return on equity. The issue for the Panel, therefore, is to determine the relevance of the difference of realized and allowed ROE. From the investors' perspective, this risk relates to the relative stability of year-to-year variations in earnings or cash flows and the value of those cash flows. Therefore, the Panel first has to assess the relevance of the disparity between "allowed" and "actual" ROE in relation to the question of whether FEI faces any short-run risks. FEI has a track record of generally achieving, and often exceeding, the allowed ROE in any particular year. Does this strong track record imply FEI having "no material short-run risk, or the risk of return on capital" as claimed by Dr. Booth? (T8:1464)

FEI's track record was explored extensively in the proceeding as shown below:

- From 2002 to 2011, there was only one year when the actual ROE was below the allowed ROE, whether assessed on a pre or post earnings sharing mechanism basis. This year was 2010, when 9.42 percent was achieved as compared to the 9.50 percent allowed, resulting in a net income variance of \$1.2 million. (Exhibit B1-20, BCUC 1.95.1)
- A similar trend is also apparent from 1994 to 2001. (Exhibit B1-10, BC Utility Customers 1.2.1; Exhibit C6-12, pp. 27-29)
- FBCU stated that the data set used by Dr. Booth is largely from years in which a Performance Based Rate (PBR) mechanism was in place for FEI. During the PBR period, O&M and capital were set through a formula, not based on forecast spending. The PBR formula approach was designed to result in savings to be shared with customers, primarily from the operational consolidation of three separate utilities. The Commission-approved framework expressly anticipated earnings that were above the allowed ROE. FBCU argue that when the periods under PBR are excluded, the variances between FEI's achieved return and allowed ROE from 1994 to 2011 were not that significant. (FBCU Final Submission, p. 40; Exhibit B1-20, BCUC 1.96.1.1)
- For the PBR period 2004 to 2009, after sharing, the average ROE over the period is .67 percent over the allowed ROE. (Exhibit B1-32, Rebuttal Evidence, p. 3)

Submissions by Parties

FBCU submit that the relative consistency of utility sector earnings in Canada tends to suggest lower short-term risk than for non-regulated companies, but “is not synonymous with an absence of short-term risk.” (FBCU Final Submission, p. 39)

ICG submits that the Commission Panel should not accept that consistent over-earnings can be explained by PBR, and that consistent over-earning is attributable to how effectively FEI manages the regulatory risk, which it claims is its largest risk, not how effectively FEI operates the utility. ICG further argues that one should think of over-earnings during the PBR period as a regulatory benefit that can be enhanced to provide increased earnings that exceed the Fair Return Standard, and that “...the historic returns suggest that FBCU have come to expect returns that exceed a fair return.” (ICG Final Submission, p. 16)

AMPC/CEC first observe that FEI has not experienced any significant risk as “the shareholder has not cumulatively lost any money whatsoever since 1994.” AMPC/CEC submit that “year after year, FEI continues to face very little short-run risk, such that this pattern of consistent overearnings is clearly a long-term phenomenon.” (AMPC/CEC Final Submission, p. 9)

In Reply, FBCU submit “the similarly long track record among Canadian utilities of achieving or exceeding their allowed ROE suggests that Canadian regulators have long recognized that it is reasonable for a well-managed utility to be able to achieve its allowed ROE on a consistent basis.” (FBCU Reply, p. 10)

Commission Determination

The Panel notes that FBCU did not explain why, even after allowance for the sharing mechanism, the over earnings have continued. For instance, in 2011 the actual ROE was 10.15 percent as compared to the 9.50 percent allowed. Consequently, the Panel observes a noteworthy asymmetry between allowed and actual ROEs that is apparent in the frequent occurrence of annual overearnings in contrast to very few years of under earnings.

In the view of the Panel, the differences in actual and allowed ROE relate to revenue requirements and are influenced by management's ability first to forecast and then to control costs for each test period.

The Commission Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from the track record of FEI. However, there is no evidence to suggest they are likely to make a major distinction between short-term and long-term risk. Accordingly, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach.

4.0 CAPITAL STRUCTURE

4.1 Definition of Risk

Dr. Booth has described the most basic definition of risk as “the probability of incurring harm, which in a financial sense means losing money.” Ms. McShane agreed with this definition noting that it was consistent with her own testimony which defined risk as the probability that the utility’s future returns (including the return on and of capital) will fall short of returns that investors expect and require. Mr. Dall’Antonia put a finer point on it as he described a loss as not earning a fair return or more specifically, a loss is anything that is less than the allowed ROE. (Exhibit B6-12, Dr. Booth Evidence, p. 26; Exhibit B1-15, AMPC 1.4.1; T2:123-124)

The Commission Panel takes no issue with the basic definition of risk as provided by Dr. Booth. However, for this Decision, the Commission Panel views risk as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations. In addition, the Panel recognizes the risk of potential financial disruption. We also accept the distinction outlined in both the 2006 Decision and the 2009 Decision where investment risk was described as comprising the sum of business risk, financial risk and regulatory risk.

Both Ms. McShane and Dr. Booth addressed business risk in terms of short-term and long-term risks, a distinction the Commission Panel considers appropriate. Each of these is discussed separately in Sections 4.2 and 4.3.

Dr. Booth has described short run utility risk as the risk of earning a return on capital and long run utility risk as the risk of earning a return of capital. (Exhibit C6-12, p. 25) Ms. McShane comments that both the capital structure and the ROE incorporate elements of long-term and short-term risks. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 39) The Commission Panel does not disagree with Ms. McShane but notes that long-term risk, which Ms. McShane outlines as being of primary importance to the utility investor, is primarily reflected in the equity structure determined for FEI considering the investors’ ability to recover their invested capital. This is because if the underlying risk decreases, more debt can be issued; if it increases, the common equity ratio would increase resulting in less debt. Therefore, as pointed out in the 2009 Decision: “The assessment of risks has

a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes.”

4.2 FEI’s Long-Term Risk

In the 2009 Decision, eight factors that influenced FEI’s long-term risk were identified. They were:

1. Provincial Government climate and energy policies;
2. The effect of aboriginal rights issues;
3. The competitive position of natural gas relative to electricity;
4. Percentage of new construction being captured by Terasen Gas Inc. (TGI);
5. Natural gas vs. Electricity in high density housing;
6. The impact of Alternative Energy Sources on TGI;
7. Changes in demand related to fuel switching; and
8. Use of natural gas per customer account.

FBCU has stated that the same risk factors are at play in the current proceeding, although they have been expressed and organized somewhat differently. (FBCU Final Submission, pp. 47-48)

For the purposes of examining the long-term risk of FEI, items 4 and 5 related to the capture rate of new construction and the energy choice for high density housing are combined under the more general heading “Customer Growth.” Items 7 and 8 related to use per customer and fuel switching related demand are also combined under the new “Market Demand and Throughput” heading. In addition, two new factors which received little or no coverage in the 2009 proceeding are addressed: “Supply Risk” and “Regulatory Risk.”

4.2.1 Provincial Government Climate and Energy Policies

In the 2009 Decision, the provincial government climate and energy policies of the previous few years played a significant role. During the period leading up to the proceeding, the provincial government published the “BC 2007 Energy Plan,” introduced numerous pieces of legislation (principally in the area of greenhouse gas emissions reduction) and in 2008 implemented the BC Carbon Tax. In the 2009 Decision, the Commission was in agreement with TGI’s position that the climate change legislation had created a level of uncertainty which did not exist during the 2005

hearing and stated that the change in government policy “will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity.” (2009 Decision, pp. 36-38)

Submissions by Parties

The Commission Panel notes that there is considerable disagreement among the parties concerning the level of risk related to provincial government climate and energy policies. In the current proceeding, FBCU have ranked political risks in the number 2 risk category and submit that the risks associated with policy and legislation are equal to if not greater than in 2009. FBCU note that all of the legislation and policy relied upon by the Commission in the 2009 Decision remains in place and the introduction of the *2010 Clean Energy Act (CEA)* has had the following impacts:

- It has precluded natural gas utilities from using incentives to promote fuel switching (electricity to gas).
 - It has required the Commission to account for enumerated energy objectives in the course of considering certain types of applications.
- (FBCU Final Submission, pp. 53-56)

Both BCPSO and AMPC/CEC submit that conditions are far more favourable today and the resulting political risks are much lower today than TGI portrayed in 2009. In support of these submissions, they point to a number of factors:

- the lack of plans to increase the carbon tax;
- the introduction of the BC Natural Gas Strategy and its support of natural gas as a transportation fuel; and
- a collapse of the Western Climate Initiative and lack of progress on emissions-trading initiatives.

(BCPSO Final Submission, pp. 15-16; AMPC Final Submission, pp. 22-23)

Commission Determination

The Commission Panel finds that the risks related to provincial government climate and energy policy are less significant when compared to the period leading up to the 2009 Decision. At the time of the 2009 proceeding, there was considerable concern and uncertainty related to provincial

energy policies, how they would be shaped in the future and what impact this would have on Terasen's gas utilities. In addition, the Commission placed importance on the Nyboer Report as reflected in the following statement:

"In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers." (2009 Decision, p. 37)

The Commission Panel does not consider the current environment to be as threatening to FEI as it was perceived to be in the period leading to the 2009 Decision. As BCPSO points out, there are no plans to raise the carbon tax beyond the current \$1.50 per GJ level and as AMPC/CEC reports, the Western Climate Initiative has collapsed and emission trading has become a dormant issue. These all reflect a less threatening current environment and with it, a lessening of risk associated with provincial government climate and energy policies.

4.2.2 Aboriginal Rights

In the 2009 Decision, the Commission Panel acknowledged that risks posed by First Nations did not exist previously and to the extent that they were currently perceived, represented an increase in risk over natural gas local distribution companies operating in other provinces. However, the Commission did not consider that risks posed by First Nations cast doubt over Terasen Gas Inc.'s "ability to earn a return on or of its capital." (2009 Decision, p. 37)

Submissions by Parties

FBCU acknowledge that aboriginal rights issues, which they rank in category 2, are much the same now as they were in 2009 and note that this issue was not addressed by the parties in IRs or at the hearing. (FBCU Final Submission, p. 49)

BCPSO argue the amount of aboriginal rights risk should be reduced relative to 2009, given the FBCU experience and understanding of aboriginal rights and title claims resulting from First Nation consultations tied into CPCN Applications. (BCPSO Final Submission, p. 17)

AMPC/CEC submit that this risk remains unchanged from 2009 where it was given no weight and this remains appropriate. (AMPC/CEC Final Submission, p. 24)

Commission Determination

The Commission Panel agrees with the FBCU and AMPC/CEC and find that there is no evidence to suggest that there has been a significant change to risk associated with aboriginal rights based on the evidentiary record of this proceeding. We also concur with the 2009 Decision that the risk associated with aboriginal rights has little impact on the FEI's ability to earn a return.

4.2.3 Competitive Position of Natural Gas Relative to Electricity

The competitive position of natural gas to electricity is an existing risk which bears scrutiny at each cost of capital proceeding. In the 2009 Decision, the Commission Panel took note of the interveners' position that the risk related to the competitive price of natural gas and electricity had diminished since 2005. However, the Panel considered that the competitive edge which existed was dependent on too many significant variables to be considered permanent. (2009 Decision, p. 36)

Submissions by Parties

The FBCU acknowledge that natural gas prices have fallen but submit that this occurred prior to the 2009 Decision and take no issue with the fact that the development of shale gas is a "game changer" or that there has been an increase in electricity prices. They do take issue with Dr. Booth's conclusion that long-term business risk has declined since 2009 and argue that his reliance on considerations related to cost-effectiveness paints an incomplete, distorted view of FEI's overall competitive position. FBCU make the following arguments in support of their position:

- Natural gas prices fell substantially prior to the 2009 hearing due to shale gas development and this was reflected in the evidentiary record leading to the 2009 Decision.
- Volatility in natural gas prices affect natural gas to electricity competitiveness and has increased due to the suspension of hedging instrument tools resulting from the 2011 Price

Risk Management Decision (PRMP Decision).⁵ Looking ahead to 2017 there is a wide potential price range for natural gas based on the AECO Forward Curve. (see Figure 2 below)

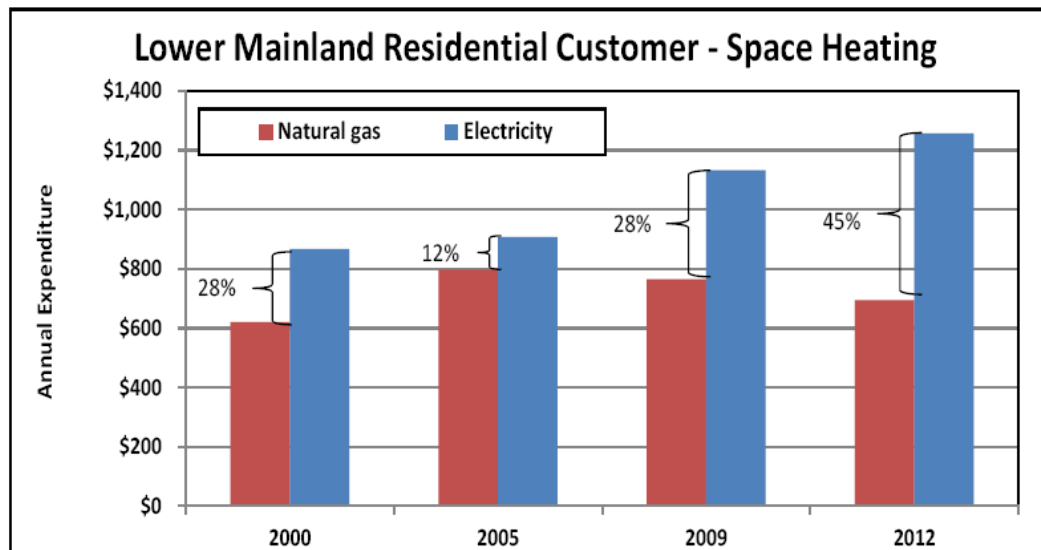
- The price of the natural gas commodity has decreased but the delivered cost of natural gas remains almost the same as 2009.
- Higher capital costs for natural gas heating materially diminish the operating cost advantage of natural gas over electricity.
- Non-price factors such as the desire to create a smaller carbon footprint have resulted in more customers being willing to adopt lower carbon and renewable energy sources.

(FBCU Final Submission, pp. 57-71)

ICG, relying on Figure 1 below, argues that there has been a significant improvement with respect to cost competitiveness between natural gas and electricity since both the 2005 and the 2009 proceedings.

Figure 1: Estimated Annual Expenditure

Figure 1: Estimated Annual Expenditure for FEI Lower Mainland Residential Customer – Natural Gas and Electricity for Space Heating

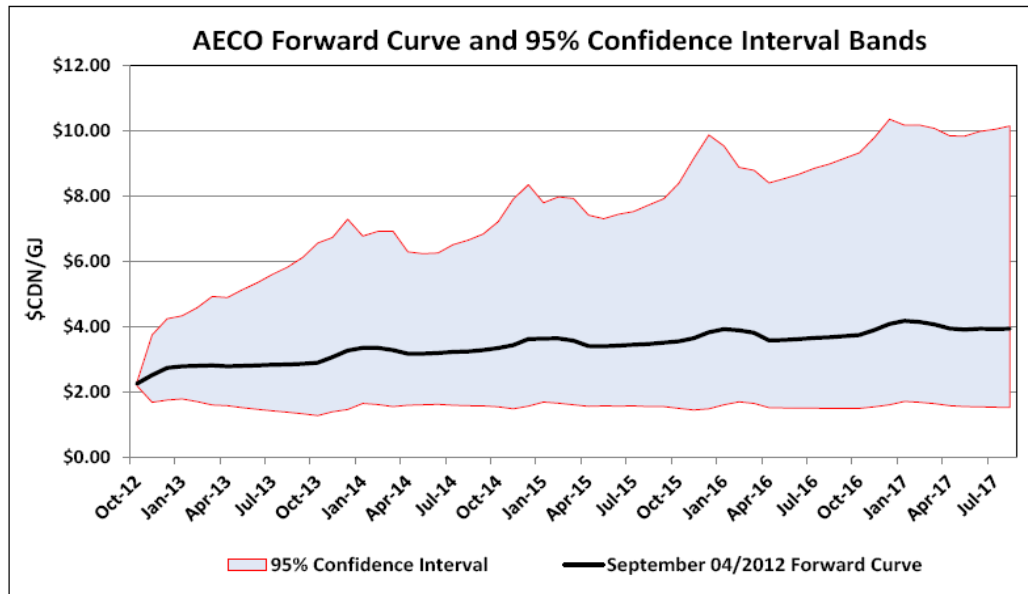


(Source: Exhibit B1-11, FBCU Response to BC Utility Customers, 1.4.2)

ICG contends that shale gas has been a game changer for natural gas prices, which has resulted in a “seismic” shift in the competitiveness of natural gas versus electricity. (ICG Final Submission, p. 11)

⁵ Order G-163-11

Figure 2: AECO Forward Curve



(Source: Exhibit B1-20, BCUC 1.105.1)

BCPSO notes that there has been no change in FBCU's rating of capital cost and it is the same as in 2009. It argues there is no evidence that the effect of higher capital costs will offset any competitive gain made through lower commodity prices. Further, BCPSO submits that the AECO Forward Curve relied upon by FBCU demonstrates only an increasing level of price uncertainty over time, not volatility. BCPSO also takes issue with the FBCU claim that there is effectively no reduction in the customers overall bill. The important comparison is not natural gas against itself but against electricity, and this comparison is very favourable to FEI. (BCPSO Final Submission, pp. 9-10)

AMPC/CEC state that price is a key determinant of natural gas competitiveness and deserves the greatest weight when considering changes to FEI's business risk. In answer to FBCU's claim that the delivered cost of natural gas is similar to 2009, AMPC/CEC argue that prices are at or near a ten-year low and by FBCU's evidence (in Figure 3 below) are lower than 2009 and even more so when compared against 2005. (AMPC/CEC Final Submission, pp. 11-13)

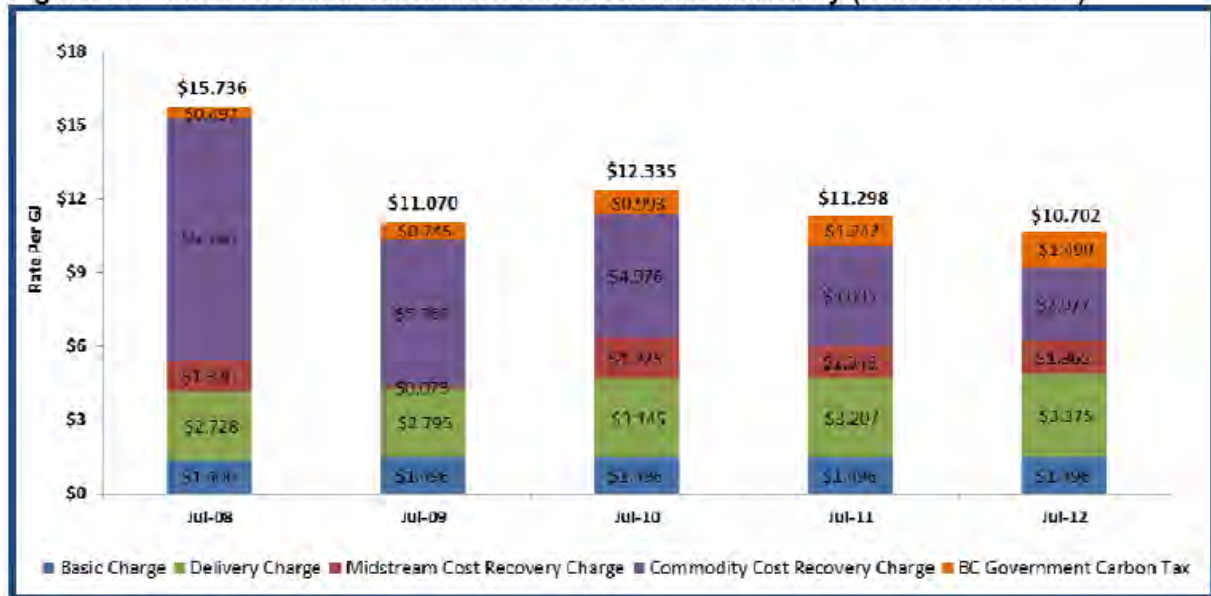
AMPC/CEC assert that the volatility is manageable through options, including equal payment plans and deferral accounts which FEI currently uses. AMPC/CEC notes that in addition to these options, FEI is proactive in communicating the natural gas cost advantage relative to other sources.

AMPC/CEC also submit that a telling point with regard to competitiveness is how it compares to electricity. They assert that FBCU's response to AMPC/CEC 1.4.2 (Exhibit B1-15) outlines the savings of natural gas over electricity for space heating (and to a lesser extent water heating) and demonstrates a trend that continues to widen. In their view, this information demonstrates that FEI is the beneficiary of both a reduction in gas prices and rising BC Hydro rates. (AMPC/CEC Final Submission, pp. 11-16)

In Reply, FBCU argue that using November 2009 rather than July 2009 is a more appropriate point of comparison and represents a variance of less than 3 percent. They also point out that this difference has been insufficient to drive behavioral changes in new and existing customers. (FBCU Reply, p. 14)

Figure 3: Delivered Cost of Natural Gas

Figure 34. FEI Lower Mainland Annual Residential Bill History (Rate Schedule 1)



(Source: Revised Exhibit B1-9-6, Appendix H, p. 51, Figure 34)

Additionally, FBCU state that they have not suggested that there is an increase in price volatility, but rather they have fewer tools to deal with it. Overall, FBCU submit that commodity price volatility is a risk factor which remains undiminished since 2009. (FBCU Reply, pp. 14-15)

Commission Determination

The Commission Panel considers price, because of the importance placed on it by the consumer, to be a key determinant and deserves significant weight when considering changes to FEI's risk. **The Commission Panel finds that there has been some reduction in the level of risk associated with the competitive position of natural gas as compared to electricity.** It is difficult to reach any other conclusion given there has been a reduction in the total billing costs while over the same period the cost of electricity has risen regardless of the timeline one chooses for comparison. The evidence relied upon by the interveners in Figure 1, which details the growing variance between natural gas and electricity, is persuasive and it is unlikely that a price conscious customer would move away from natural gas in these circumstances. Looking ahead, and relying upon the information in Figure 2 above, the Panel notes that in spite of the range considered to fall under the 95 percent interval band, the September 4, 2012 AECO Forward Curve projects relatively stable natural gas commodity costs looking out to 2017. While hardly definitive, this does point to some level of stability over the next few years.

Notwithstanding these favourable conditions, the Commission Panel does place some weight on the lack of change in the purchasing behaviour of new and existing customers. In our view, some of this relates to the higher capital costs required to convert to or install natural gas service and the move to multi-family dwellings, which is discussed in Section 4.2.4.

FBCU state that price volatility is a risk factor that remains undiminished since 2009. Based on the evidentiary record we agree. However, we are not in agreement with the assertion that FEI have fewer tools to manage volatility. In the PRMP Decision, the Commission Panel offered a number of suggestions or options FEI may wish to consider. Included among these was offering the PRMP program to existing customers on a permission basis. There is no evidence before the Panel to indicate any action that FBCU has taken to bring alternatives forward.

4.2.4 Customer Growth

Submissions by Parties

FBCU note that a continuing trend has been its lower capture rate on new construction and reports a decline in the rate of net residential customer additions when 2011 is compared against 2007. In addition, the FBCU submits that new customer usage is roughly half what it used to be and therefore, the trend that existed in 2009 has not changed. FBCU states that this trend is closely associated with growth of multi-family dwellings in BC, a market where FEI has low penetration driven by unfavourable installation economics. This shift toward multi-family dwellings means that FEI's capture rate will further decline over time. (FBCU Final Submission, pp. 50-51; Exhibit B1-9, Appendix H, pp. 33-37)

AMPC/CEC point out that in spite of the challenges faced by FEI in growing customers, its total customer base continues to grow. The number of residential customers grew by 8 percent over the period 2005-2011 and the number of commercial customers grew by 5 percent over the same period while there was some decline in the number if not the consumption of industrial customers. (AMPC/CEC Final Submission, pp. 16; Exhibit B1-11, BCUC 1.4.4)

Commission Determination

The Commission Panel notes that the circumstances related to unfavourable installation economics and the shift toward multi-family dwellings existed at the time of the 2009 Decision. In spite of this, the total number of customers continues to grow if not the market share of potential new customers. **Therefore, the Commission Panel finds that there is no persuasive evidence to suggest there has been a shift in risk related to customer growth.**

4.2.5 Impact of Alternate Energy Services on FEI

Submissions by Parties

FBCU state that the "adoption of energy forms produced in combination with newer technologies represents a challenge to FEI's core business for providing natural gas for space and water heating." The recent number of energy projects approved serves to demonstrate the momentum behind

alternative energy which FBCU rate in the number 2 risk category. In FBCU's view, the growing consumer awareness of alternative energy and its green attributes and increasing cost effectiveness demonstrate the importance of this risk factor for FEI. (FBCU Final Submission, p. 52; Exhibit B1-9, Appendix H, p. 28)

AMPC/CEC argue that this represents double counting and there is no evidence to suggest that there is more risk posed by alternative energy to FEI than that which existed in 2009. Further, they argue that the new transportation technology will result in improved prospects as it allows natural gas to replace diesel in heavy trucking thereby increasing natural gas demand in the future. (AMPC/CEC Final Submission, p. 18)

Commission Determination

The Commission Panel notes that the impact of AES sources on FEI is not a new risk. However, we do acknowledge that in the three years since the 2009 proceeding, there has been greater momentum behind alternative energy forms and the adoption of new technology related to them. Therefore, the Panel is mindful that there is the potential for an increase in risk related to AES but, given that much of this risk has been accounted for in reference to FBCU's share of multi-family dwellings, it is difficult to quantify.

4.2.6 Market Demand and Throughput

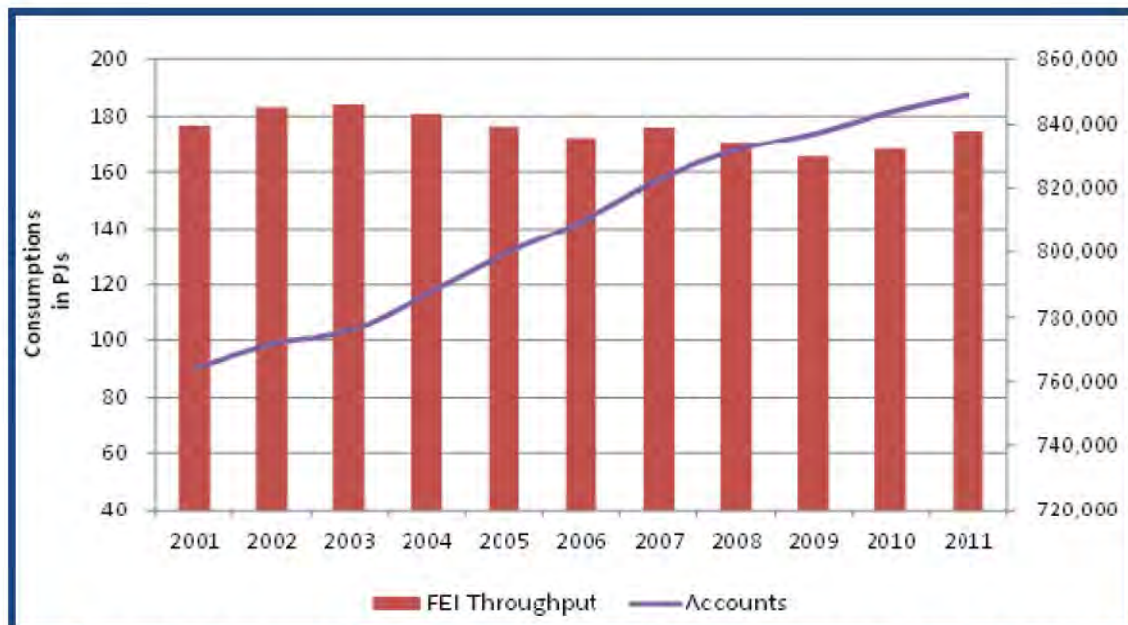
Submissions by Parties

The FBCU state that FEI's use per customer (UPC) for both new and existing customers has been declining; this trend, based on a Conservation Potential Review Study, is expected to continue until 2030. Contributing to this decline are a variety of factors including technological advances and energy efficiency improvements. In addition, the decline in UPC can, in part, be attributed to increased efficiency standards, better building envelopes and a move to smaller dwellings. Further, FBCU state that new construction research since the 2009 hearing shows that natural gas has been increasingly used as a secondary fuel source in new homes rather than the primary source. The FBCU state that there is no reason to believe the drivers behind these market trends will cease. (FBCU Final Submission, pp. 52-53; Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

ICG states that Exhibit B1-41 shows that there has been no decline in system throughput since 2009. In addition, ICG asserts that there is an upward trend in industrial throughput, which is reflective of lower natural gas prices over the same period. Given this recent trend, ICG argues that the Commission should not accept the FBCU's 2013-2016 lower industrial throughput evidence and conclude that business risks are in fact lower than in 2009. (Exhibit B1-41, Undertaking No. 6, p. 3; ICG Final Submission, pp. 7-9)

BCPSO notes that the Commission acknowledged the risks related to throughput in its 2009 Decision and, as a result, they are not new. BCPSO, like AMPC/CEC, further submit that based on graphical information in Figure 4 below, the trend of declining throughput has reversed itself in 2009 and has increased each year since. (BCPSO Final Submission, pp. 13-14)

Figure 4: FEI's Total Throughput (Normalized Demand vs. Customer Accounts)



Note: This graph includes Lower Mainland, Inland, Columbia and Revelstoke service areas. Industrial demand includes both sales and transportation volumes.

(Source: Exhibit B1-9-6, Section H, p. 9)

AMPC/CEC submit that the evidence presented by FBCU shows that both commercial and industrial UPC has increased since 2009, while residential UPC has decreased only marginally.

AMPC/CEC further submit that as the Commission considers the issue of declining UPC, it should consider two points:

- The residential throughput would have to decrease by 83 percent in 2012 to drive its distribution margin to a level equal to BC Hydro Tier 2 Rates; and
- The negative trend related to the creation of energy efficiency is no different than that faced by BC Hydro.

AMPC/CEC argues that these energy trends are not new and there is only risk if they affect the utility's ability to earn a fair return which, in their view, is not supported by the evidence on the record. (AMPC/CEC Final Submission, pp. 16-18)

In Reply, FBCU submit that revenues related to increased throughput are largely unaffected due to the structure of industrial contracts that only generate additional revenue if consumption exceeds an agreed upon level. Therefore, the declines in residential and commercial UPC continue to have a disproportionate impact on FEI. FBCU also point out that AMPC/CEC's reliance on Tier 2 rates is inappropriate. In addition, they argue that the AMPC/CEC's position is based on the view that existing customers will not leave natural gas until there is no longer a price advantage. FBCU state that this assumption is unwarranted given recent research that people are less committed to natural gas, irrespective of price. (FBCU Reply, pp. 16-17)

Commission Determination

The Commission Panel finds that there is insufficient evidence to support a finding that there has been a shift in risk related to market demand and throughput.

The Commission Panel notes that the decline in UPC and overall throughput were issues raised in the 2009 proceeding. Based on the evidence in this proceeding, it is apparent that the overall throughput has increased since 2009 and UPC, while decreasing overall, has increased for both commercial and industrial customers. In the view of the Panel, these are all positive but not conclusive signs.

The Commission Panel places little weight on the FBCU submission that the increased throughput has not resulted in increased revenue due to the structure of industrial contracts. Notwithstanding our understanding that industrial contracts are subject to competitive negotiations, in our view, FBCU nonetheless has some control over the structure of and risks related to the contracts it negotiates.

The Commission Panel does not consider the research indicating existing customers are less committed to natural gas in spite of the price advantage to be persuasive. The Panel notes that much of the research referred to in this context was related to AES options, which have been considered as part of the growth of multi-family dwellings addressed in Section 4.2.4. (Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

4.2.7 Supply Risk

Submissions by Parties

FBCU's position is that BC's shale deposits do not guarantee a reliable supply of natural gas at reasonable prices. Due to the higher cost of development relative to other areas and a lack of infrastructure for resource development and market connection, FBCU state that growth of production in northeastern BC has stopped and there is risk of current levels declining. This is in contrast to developments like the Marcellus Formation in the northeast part of the continent that is thriving. FBCU submit that this leads to the possibility of stranded resources or, at a minimum, higher market prices and an expansion of access infrastructure to encourage expansion of BC's shale gas resources.

FBCU also submit there is a lack of new development of infrastructure to move gas to FEI's service territory. They argue that the development of gas transmission infrastructure projects connecting BC sources with Alberta and Eastern markets, combined with the potential for LNG exports, could change the historical pricing relationship between BC supply and Alberta production leading to higher consumer prices in the future. (FBCU Final Submission, pp. 60-61)

AMPC/CEC describe the potential for stranded resources in northwestern BC as nonsensical. They submit that the impact of shale gas development on prices was not recognized, as it was not mentioned in the 2009 Decision. They also refer to the following statement of Ms. Des Brisay in the current proceeding:

“What was not fully understood is how low the cost could be in terms of how we produced that resource, and that’s really where we have seen the shifting of the curve has been as we have a better understanding of the economic feasibility of the development of shale gas reserves in different parts of North America.”
(T2:161)

Therefore, AMPC/CEC argues the existence of reserves may have been known in 2009, but the understanding of the economic feasibility of development has shifted since then. (AMPC/CEC Final Submission, p. 19)

AMPC/CEC submit that any weight the security of supply factor deserves pales when compared to the availability of supply. The Commission Panel notes they did not comment directly on the potential change to the historic pricing relationship between Alberta and BC. (AMPC/CEC Final Submission, pp. 18-20)

As noted previously, FBCU acknowledge that shale gas has been a “game changer” and that supply risk has declined. They did make the following points:

- There was knowledge of natural gas reserves prior to the 2009 proceeding.
- The price of natural gas must be higher (leading to higher rates) before supply will be extracted.
- FEI’s ability to access cost effective supply could be challenged as there are competing markets for natural gas.

FBCU argue that it is the factors affecting demand for delivered natural gas, not energy supply considerations, that are the key supply risk for FEI. (FBCU Reply, pp. 19-20)

Commission Determination

The Commission Panel finds that there has been a decrease in the risk associated with the supply of gas but an increase in the risk associated with access to this gas at low prices. Balancing the two, there has been no material change in the level of risk related to energy supply.

The Commission Panel accepts the statement of Ms. Des Brisay as informative and a reasonably accurate reflection of where matters stood at the time leading up to the 2009 Decision. There is clearly no disagreement among the parties with respect to the existence of adequate supply of natural gas and FBCU have conceded that the actual supply risk has declined. Therefore, the issue is not whether natural gas will be available but whether sufficient natural gas will be available at the low commodity price levels that the consumer has come to expect. To this end, FBCU have laid out a number of facts and potential scenarios which they argue will have a significant impact on the supply of low cost natural gas. None of the interveners have challenged this information except AMPC/CEC who characterized the potential stranding of assets as “ludicrous.”

In our view, the potential for some of FBCU’s concerns to become a reality cannot be dismissed. The stability of the current environment remains uncertain, as does the magnitude of future development of the LNG business. Until this has been determined, the continuity of current low price levels for natural gas will be at some risk. However, the risk of supply to the extent that it existed, has abated and shifted to the risk associated with maintaining existing commodity price levels with no resulting increase in overall risk.

4.2.8 Regulatory Risk

Submissions by Parties

FBCU has ranked regulatory risk as their highest risk area with a number of factors in the “higher risk” category. In assigning this weighting, FBCU states that FEI is dependent on regulatory approvals that determine its revenue requirements, cost of service recovery and approval of investments. FBCU submit that the pace of change in the energy policy and environment has

increased at a time when the Commission's role in implementing and applying policy has expanded. This has contributed to increased uncertainty in the regulatory environment and added process as compared to 2009. (Exhibit B1-9-1, Section H, pp. 5-6)

BCPSO points out the FBCU witnesses have confirmed that the regulatory environment is predictable and stable and regulatory risk should not be viewed as its number one risk factor. (BCPSO Final Submission, pp. 14-15)

AMPC/CEC questions the FBCU ranking of regulatory risk as there is no compelling evidence to suggest that FEI faces greater regulatory uncertainty than it did in 2009. (AMPC/CEC Final Submission, pp. 10, 20)

In Reply, FBCU acknowledge that the relative stability and predictability of the BC regulatory framework reduces regulatory risk. However, they point out that the breadth of the Commission's influence on FEI's business is undeniable and individual decisions can have significant implications for FEI particularly in the short-term. While they identify "regulatory risk as being 'higher,' any change since 2009 was not material to FEI's overall risk." (FBCU Reply, p. 12)

Commission Determination

The Commission Panel finds that there has been no material change in the level of risk associated with regulatory risk.

The Commission Panel accepts that the BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI. However, we agree with the parties that argue there has not been a material change since the 2009 Decision.

4.3 FEI's Short-Term Risk

There are two issues that must be considered by the Commission Panel with respect to short-term risk. The first is whether there has been a change in short-term risk since the 2009 Decision. The second is how much of FEI's short-term risk has been mitigated and, as a result, how much of the remaining risk must be considered. In the view of the Commission Panel, this will be determinative

as to the level of weight to be placed upon the short-term risk in this proceeding. FBCU has expressed disagreement with the need to determine the level of short-term risk in reply to BCSP0 submissions:

“The Commission need not attempt to characterize or quantify FEI’s short-term risk to determine a fair return for FEI. The question requiring a determination is the extent to which FEI’s short-term risk has changed since 2009.” (FBCU Reply, p. 9)

The Commission Panel disagrees. There are many measures of risk. The overall level of risk may not have changed substantially but one needs to consider the individual risk elements and their weighting. These may have changed and therefore, not considering them may be a mistake.

4.3.1 Change in Short-Term Risk

Submissions by Parties

The FBCU submit that short-term risk is essentially the same as in 2009. (FBCU Final Submission, p. 45)

Both FBCU and the interveners have focused their submissions on two areas in examining short-term risk:

- FEI’s record of generally being able to earn its allowed ROE; and
- The amount of risk mitigation provided by deferral accounts.

Matters related to FEI’s history of typically earning its ROE were dealt with in Section 3.3, where it was determined that actual earnings versus approved earnings history is more appropriately a matter for consideration in revenue requirements proceedings.

Concerning the use of deferral accounts, FBCU submit that “FEI’s ability to manage short-term risk with deferral accounts is a function of the portion of the overall revenue requirement covered by deferrals, irrespective of the number of accounts providing that coverage.” They also submit that there has been no material change in the collective scope of deferrals having an effect on earnings

volatility. In the view of FBCU, their evidence on deferral accounts shows that the percentage of revenue requirements covered by deferral accounts has decreased and has resulted in a credit to customers. (FBCU Final Submission, pp. 38-45)

AMPC/CEC acknowledge that some of the additions in deferral accounts since 2009 are a reflection of accounting changes, but submit that three new accounts (Compliance to Emission Regulation Account, Customer Service Variance Account and Depreciation Variance Account) are significant. They further submit that while the new accounts may not represent a monumental change, they are an indication of FEI's ability to obtain such accounts. Therefore, this risk factor is lower today than in 2009. (AMPC/CEC Final Submission, p. 22)

BCPSO agrees with the submissions of AMPC/CEC and submits that the addition of the three new accounts demonstrates the Commission's willingness to mitigate the impact of short-term uncertainties. It concludes that the new accounts indicate short-term risk is no greater and likely less. In sum, BCPSO submit that short-term business risk is lower than in 2009. (BCPSO Final Submission, pp. 8-9)

FBCU, in reply, assert that the submissions of AMPC/CEC are at odds with the evidence of their witness, Dr. Booth, "who admitted that FEI risk hadn't changed "in the slightest."" The Commission Panel notes that Dr. Booth (T8:1475) was referring to ROE and not overall risk. FBCU conclude that short-term risk when compared to risk faced by its peers in other jurisdictions, remains unchanged. (FBCU Reply, p. 9)

Commission Determination

The Commission Panel, after reviewing the evidence, finds that there has not been a material change to FEI's short-term risk since the 2009 Decision. However, to the extent that there have been additional deferral accounts added, there is a greater ability to mitigate short-term risk. The Commission Panel agrees with BCPSO that the Commission's approval of the new deferral accounts demonstrates a willingness on the part of the Commission to mitigate the impact of uncertainty. However, in the Panel's view it is not important how the deferral account came to be. It is the

effect. Therefore, the fact that the Depreciation Variance Account was ordered by the Commission, as noted by FBCU, in our view, is immaterial. More important is the fact that the deferral account now exists, as it reduces the risk associated with unforeseen variances in depreciation amounts.

4.3.2 Magnitude of Short-Term Risk

The second question to be considered by the Commission Panel with respect to short-term risk relates to the level of mitigation which has or could be applied against short-term risk. Much of the evidence related to this was focused on the use of deferral accounts which we explore below.

Revenue Related Deferral Accounts

The FBCU consider the overall risk for residential and commercial sales to be moderate and have assessed the risk of industrial sales to be high.

In 2011, residential and commercial sales accounted for 87.9 percent or \$485.4 million of the total delivery margin revenue of \$552.3 million. FBCU are protected for changes in use per customer for residential and commercial sales through the Rate Stabilization Adjustment Mechanism (RSAM). In assessing these risks as moderate, FBCU point out they are not protected for any differences in actual and forecast number of new customers in a given test period. The Commission Panel notes that impact of any variance in customer additions is likely to be minor, given the relatively small number of new customer additions as a function of the existing customer base. **Given the relatively heavy reliance on existing customers for most of the revenue and the existence of the RSAM, the Commission Panel finds the short-term risk related to residential and commercial sales to be low rather than moderate as suggested by FBCU.**

Industrial sales account for 12.1 percent or \$66.8 million of the delivery margin revenue in 2011. FBCU assess the risk as high in this area because there are no deferral accounts utilized with this customer group. (Exhibit B1-20, BCUC 1.96.1)

In reviewing the submissions, the Commission Panel notes the following statement made by FBCU in reply to AMPC/CEC submissions: “Increased consumption by industrial customers only generates additional revenue if the consumption **exceeds a customer’s fixed contract demand** (i.e., the ‘take

or pay' volume).” [emphasis added] Notwithstanding the impact on revenue as addressed in this statement, it appears to the Panel that the lack of deferral accounts in the industrial category is because there is no need as this area is run on a contract basis with a reliance on “take or pay” contracts. (FBCU Reply, p. 16) It is therefore evident that potential risk is mitigated to a large extent by the existence of such contracts. **For these reasons, the Commission Panel finds that a “high” risk rating for industrial sales is inappropriate and a moderate to low rating is more appropriate to the level of risk.**

Expense Related Deferral Accounts

Table 1 of the FBCU response to BCUC IR 1.96.1.1 indicates that in 2011, 75.3 percent (\$1,160.7 million) of the FEI revenue requirement or 31.0 percent (\$171.1 million) of the Revenue Margin Delivery Requirement was covered by way of deferral accounts. Overall, the single biggest expense item was cost of gas, which at \$989.6 million is 100 percent covered by deferral mechanisms.

FBCU’s Operation and Maintenance (O&M) Expense totalled \$184.6 million. Of this, approximately 9 percent encompassing Pension & OPEB Variance, Insurance Variance and BCUC Levies Variance Deferral is covered by deferral accounts. FBCU rates the overall risk of O&M Expense as high citing the small portion covered by deferral accounts in explanation.

The Commission Panel also notes that of the remaining revenue requirements categories, Property and Sundry Taxes (\$50.2 million), Financing Costs (\$108.5 million) and Depreciation and Amortization (\$99.9 million) are at or near 100 percent deferral account protection levels. (Exhibit B1-24, BCUC 2.182.1; Exhibit B1-20, BCUC 1.96.1)

The most significant area not covered to a large degree by deferral accounts is O&M Expenses. O&M Expenses are also an area where there is a history of under spending approved O&M amounts. Under cross-examination, Mr. Dall’Antonia explained that risks at the start of each test year are the same and the success of managing within budgets can be attributed to management’s experience and being sound managers. (T3:344) While the Commission Panel does not take issue with Mr. Dall’Antonia’s comments, we are of the view that in addition to this, FEI has a broad range of options available to it to manage O&M budgets effectively. For example, many of the initiatives in an approved O&M plan can be postponed for short periods or in some cases not implemented

within the test period. This could include items such as routine maintenance, new staff additions, replacement of staff vacancies or delaying of new programs or initiatives. This may, in part, account for the fact that O&M expenditures were less than forecast in 8 of the last 9 years. (Exhibit B1-24, BCUC 2.182.1) Therefore, in the view of the Commission Panel, this is an area where FEI has a high degree of control. **Accordingly, the Commission Panel finds that a high risk rating for O&M expenses is not appropriate and a moderate to low rating is more reflective of the risk FEI faces.**

Another area with a high risk rating due to limited use of deferral accounts is Other Operating Revenue which encompasses things like late payment charges, NSF cheques, and connection charges. This item has been in the \$20 to \$25 million range over the last nine years, which is a relatively small part of revenue requirements. However, as outlined in Undertaking No. 8, there have been consistent negative variances (meaning revenues were less than approved) in the \$2 million range for all but the most recent completed year. (Exhibit B1-24, BCUC 182.1; Exhibit B1-20, BCUC 1.96.1; T2:293-294; Exhibit B1-43)

The Commission Panel acknowledges that many of the Other Operating Revenue areas are less predictable and controllable in nature and most items are not covered by deferral accounts. Therefore, the Commission Panel finds that a high risk rating is appropriate.

Commission Determination

Given our findings with respect to revenue risks and risks in expense areas not covered by deferral accounts, the Commission Panel is not persuaded that on balance FEI faces significant short-term risks to its achieving its allowed ROE in a given test period. While including items that are less predictable or controllable, the Other Operating Revenue item generally shows a consistent pattern of under earning revenues. However, their impact on the total revenue requirements is relatively small. **Therefore, acknowledging that there has been little change in short-term risk since the 2009 Decision, the Commission Panel has determined that only minimal weight can be given short-term risk as an impediment to earning a fair return.**

4.4 Developing an Optimal Capital Structure

An important component of the Panel’s task is to determine an allowed capital structure. This section is devoted to the discussion of the evidence presented that relates to the capital structure decision and presents the Commission Panel’s findings. In this section, we set out the context within which this evidence has been considered.

4.4.1 Capital Structure and the Fair Return Standard

Background on the role of capital structure on the cost of capital is provided in the Brattle Report, which recognizes that “underlying asset risk in each company is typically divided between debt and equity holders – making them derivatives of the underlying asset return.” In addition, the result of a specific capital structure is a particular Weighted Average Cost of Capital.

$$WACC = r_d(1 - T_c) \cdot \frac{D}{V} + r_E \frac{E}{V}$$

where: r_d = market cost of debt; r_E = market cost of equity; T_c = corporate income tax rate; D = market value of debt; E = market value of equity; and V = the market value of the firm (i.e., $V = D + E$).

(Exhibit A2-3, pp. 38-40)

This cost of capital reflects the equity risk and the debt risk, both of which in turn reflect both operating and financial risk, as well as the tax advantage of debt.

The integration of the capital structure decision with the ROE decision is recognized in the argument of AMPC/CEC:

“Capital structure is important for two main reasons: (1) the cost of equity is higher to reflect the greater risk of investing in shares as opposed to bonds, and (2) the cost of debt (interest) is tax deductible, whereas the cost of equity (dividends) is paid out of after-tax income. Consequently, equity is substantially more expensive than debt. . . . FEI’s customers have a right to expect that its capital structure will be efficient and the common equity component will reflect the real risks equity shareholders are exposed to.” (AMPC/CEC Final Submission, p. 32)

Ms. McShane submits that the inter-dependence between capital structure and ROE is largely based on the FRS with its three requirements i) the ability to attract capital on reasonable terms, ii) maintenance of financial integrity; and iii) comparability of returns. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 34)

These considerations translate into a focus on credit metrics and the need to maintain a particular credit rating. The FBCU does, however, discuss at length the possible disruptions that might take place if FBCU experienced a rating downgrade. AMPC/CEC submit that FBCU's credit metrics are not weak and that a 35 percent common equity ratio (as compared to its existing 40 percent ratio) "is entirely consistent with the objective of maintaining FEI's existing credit rating." (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 35-37; FBCU Final Submission, pp. 12-15; AMPC/CEC Submission, pp. 32, 34-36)

4.4.2 Commission Panel Discussion

The Commission Panel accepts the view put forth by AMPC/CEC that the capital structure should be set efficiently. The Panel also notes that debt comes with advantages, primarily the deductibility of interest payments from taxes.

At the same time, the Commission Panel recognizes the argument made by FBCU that the excessive use of debt could disrupt the operations of the company by making it difficult to finance the ongoing operations.

The Commission Panel accepts, therefore, that there are both expected benefits and expected costs associated with the use of debt. The task faced by the Panel is to determine the 'optimal' capital structure, one that is efficient in reducing the total or WACC through the use of debt without creating potential financing disruptions that could offset these benefits to the point where the net benefit is reduced.

The discussion of the capital structure evidence and determination found in this section reflects the Panel's desire to find an efficient or optimal capital structure. In doing so it applies the following principles to guide its analysis:

1. While credit ratings are important indicators of the risk of disruption, a particular rating is not in and of itself the definition of an efficient capital structure. Possible ratings downgrades are important but must be considered in terms of the attendant costs and benefits.
2. The long-run risks discussed by all parties are important considerations in determining an optimal capital structure. They indicate operating uncertainties that can cause financial distress and the possible attendant disruption and distraction of management. Since the concern is with financial disruption, both diversifiable and non-diversifiable risks must be recognized in assessing the risk of financial disruption.
3. The stand-alone principle implies that the risk of disruption due to financial distress is assessed within the context of the risks to the benchmark utility. It is in this sense that the Panel agrees with FBCU's view that FEI is not a diversified investor. (FBCU Final Submission, pp. 130-131) As discussed in Section 5, however, this does not imply that the Panel accepts this view with regard to the ROE.

4.5 Credit Ratings and Metrics

An important issue for the Commission Panel is to determine how important it is for FEI, as the benchmark utility, to maintain an "A" category credit rating among credit agencies. Credit ratings are important indicators of potential financial disruption as discussed in Section 4.4. A lowering of credit agency ratings raises concerns about the cost of debt and access to the credit market at reasonable cost. Therefore, there are clearly advantages of maintaining an ROE and capital structure which will allow for existing credit agency ratings to be maintained. However, the Commission Panel must consider whether there is a point where maintenance of a particular credit rating may result in a capital structure or ROE that is suboptimal in the circumstances. In such instances, what importance should the Commission Panel place on the maintenance of a credit rating and at what additional cost?

Presently, FEI is rated by Moody's and DBRS, with Moody's providing the lower credit rating at A3, which is just one level above a Baa rating. DBRS provides a slightly higher A rating, which is comparable to a Moody's A2 rating. (Exhibit B1-58) The Moody's rating is considered to be more vulnerable to a downgrade due to weaker credit metrics, which, with further deterioration and a less predictable and supportive regulatory environment, could result in a drop to the Baa rating. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 59) This Baa rating could reduce the financial integrity of FEI by reducing its ability to maintain credit and access capital on as reasonable terms as an A3 rating.

The Commission determined in the 2009 Decision that Moody's rating should be the focus of attention because it was the lower in the group, and that the Moody's A3 rating should be maintained with a margin of cushion to ensure the financial integrity of FEI. (2009 Decision, p. 15)

None of the interveners took the position that FEI's 'A' rating should be jeopardized. AMPC/CEC submit that a reduction of the ROE to 7.5 percent at the existing 40 percent equity ratio would still leave FEI with strong credit metrics, including a cash flow coverage ratio of 2.67, and that a combined ROE reduction to 7.5 percent and lower equity ratio to 35 percent would leave FEI with a 2.35 ratio, which would still be above Moody's stated threshold of 2.3 to maintain the A3 rating. (AMPC/CEC Final Submission, pp. 35-36)

FBCU state that their current credit metrics are already weak for the existing rating and that the combined reduction in ROE and equity ratio as suggested by AMPC/CEC would not allow it to have a margin of comfort. (FBCU Final Submission, p. 15) FBCU also state that Moody's assessment of regulatory support had already weakened because of BC provincial energy policy. (T3:366) FBCU further state that under the Trust Indenture, Dr. Booth's recommendation would result in a coverage ratio of approximately 1.97. (FBCU Final Submission, p. 77)

Ms. McShane noted that the importance of 'A' category credit ratings arises from two factors: market access and cost. With respect to market access, Ms. McShane testified that regulated issuers can at times be closed out of the market if they have less than an 'A' category rating. Ms. McShane further testified that "during the period June 2008 to January 2009, there was not a single issuer without at least one "A" credit rating who was able to issue long term debt on any terms in the Canadian market." With respect to cost, Ms. McShane states that in addition to market access issues, a rating downgrade would result in a cost increase to additional debt the company needs to raise. Further, it will also affect all of the utilities' outstanding debt as the increased cost of new debt will increase the required yield on existing debt and reduce the value of that debt. This higher cost of debt to the utility results in a higher cost of debt for ratepayers.

Ms. McShane further submits that institutional investors continue to have limits upon the amount of 'sub A' category debt they are able to hold or are restricted from holding Baa/BBB debt at all. This underscores the importance of 'A' credit ratings given the relatively small size of the Canadian market for Baa/BBB debt. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 35-37)

Mr. Engen submits that the 10 year bond yield spread for BBB/A rated utilities has been volatile and as of July 6, 2012, is at 38 basis points (bps). This is less than the 100 bps common during the 2008 financial crisis. According to Ms. McShane, over the past 15 years, the average spread between typical A and BBB rated utilities has been 75 bps. (Exhibit B1-9-6, Engen Evidence, Appendix E, p. 34; Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 36)

Commission Determination

The Commission Panel accepts that continued access to debt capital at an attractive price is an important element which benefits the shareholder and may benefit the customer. Based on the evidence of Ms. McShane and Mr. Engen, a drop to the equivalent of a BBB rating by both rating agencies would result in a borrowing rate difference which would be significant. That being said, the Panel is mindful that credit agencies like Moody's rely upon the embedded cost of debt rather than the marginal cost of debt when calculating a utility's credit metrics as argued by AMPC/CEC. (FBCU Reply, p. 22) Based on the testimony of Ms. McShane the approved cost of debt for 2013 (at 40 percent equity) is 6.8 percent. The Panel notes that current marginal rates are substantially below this level. Therefore, we conclude that the embedded cost of debt is likely to be reduced over time, even in the event of a credit downgrade.

The Commission Panel will continue to be guided by the Fair Return Standard with its three tests of financial integrity, capital attraction and comparable return in determining an appropriate capital structure and ROE. The Panel supports the maintenance of an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard.

The Commission Panel finds that there is sufficient evidence to conclude that the maintenance of an "A" category credit rating is desirable, but not at all costs.

4.6 Other Jurisdictions

There is general agreement among the parties that the major natural gas utilities in Canada should serve as comparables for FEI for the purposes of assessing FEI's capital structure. This group which includes ATCO Gas, Union Gas, Enbridge Gas Distribution and Gaz Metro was used extensively throughout the proceeding as comparators. Dr. Booth also identified Nova Scotia Power Inc. as a reasonable comparator, being a province-wide integrated electric utility.

The equity thickness ratios of the comparator group of utilities are listed below in Figure 5. The equity ratios of the Canadian comparator group range from 36 percent to 39 percent in contrast to Dr. Booth's recommended equity ratio of 35 percent and FEI's current equity ratio of 40 percent:

Figure 5: Canadian Comparative Utility Equity Ratios

Company	Equity Ratio (%)
FEI	40.00
Dr. Booth on FEI	35.00
ATCO	39.00
Union Gas	36.00
Enbridge Gas Distribution	36.00
Gaz Métro (*Quebec)	38.50

(Source: FBCU Final Submission, p. 78)

While there is common agreement as to comparable gas utilities, there is considerable disagreement among the parties as to what these comparables suggest about FEI's required common equity ratio. (FBCU Final Submission, p. 78)

4.6.1 FEI Risk Level Relative to Alberta and Ontario Utilities

FBCU submit that the Commission should find that FEI faces higher long-term risk than natural gas distribution utilities in Alberta and Ontario for the following reasons:

- Alberta and Ontario marketplaces are more favourable from the perspective of supply and infrastructure for natural gas, overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the regions, and overall gas flows;
- Electricity costs in Alberta and Ontario are not heavily influenced by low embedded costs of “heritage hydroelectricity;”
- Eastern based utilities, by virtue of their proximity to the Marcellus Formation, have seen greater benefits from shale gas than FEI;
- The growing prevalence of multi-family dwellings in BC. The FBCU note that in a hearing before the Alberta Utilities Commission in 2011, Dr. Booth described this “condification” as a “significant competitive pressure;” and
- Government policy and legislation is a long-term risk factor for FEI. Among the provinces, BC is at the forefront of GHG reduction initiatives.

(FBCU Final Submission, pp. 77-81)

FBCU point out that regardless of the analysis relied upon by Dr. Booth, his approach ended up recommending a 35 percent common equity ratio for all Canadian Utilities excepting Gaz Metro. (Exhibit C6-12, AMPC/CEC Evidence, Dr. Booth Evidence, p. 43) In this instance, FBCU had the following concerns with the analysis leading to his recommendation of 35 percent:

- Absent from the comparison was ATCO Gas which was the highest comparator at a 39 percent common equity ratio. FBCU notes that Dr. Booth puts ATCO Gas in the same risk category as FEI and perhaps a little riskier.
- There was no reference to Gaz Metro’s deemed preferred shares in his portraying them as having a common equity ratio of 38.5 percent. This effectively understated Gaz Metro’s effective deemed common equity ratio.

(FBCU Final Submission, pp. 77-82)

AMPC/CEC submit that all of the comparators have common equity ratios that are below the current 40 percent common equity ratio of FEI. They also concede that at 38.5 percent, Gaz Metro is at the top of the range. However, they submit that Gaz Metro is in a far more difficult and risky climate than FEI, given FEI’s advantage over electricity is 5 times as great as that of Gaz Metro. AMPC/CEC conclude that a common equity that is the same or greater than Gaz Metro’s 38.5 percent would be unreasonable on comparative terms. (AMPC/CEC Final Submission, pp. 33-34)

FBCU submit that neither BCSPo nor AMPC/CEC made any attempt to reconcile the inconsistencies in the comparative analysis among Canadian utilities' capital structures. FBCU further submit that Dr. Booth's submission "that ATCO Gas risk was in the same risk bucket or slightly less risky than FEI" is significant because it suggests that the 40 percent common equity ratio for FEI is justified as ATCO has a 39 percent common equity ratio. (FBCU Reply, pp. 24-25)

Commission Determination

The Commission Panel has previously considered this matter in Section 3.2. The Panel has considered the common equity ratio decisions of other Canadian jurisdictions. **However, because each province is different in terms of its levels of regulatory protection and each utility has its own set of unique circumstances which are only minimally covered in the record of this proceeding, the Commission Panel has determined that only limited weight is to be given to the outcomes of proceedings in other Canadian jurisdictions.** Accordingly, evidence related to the equity ratios of other jurisdictions is used as a reference point only in determining whether FEI's is in an appropriate range.

4.7 Capital Structure – Commission Determination

The Commission Panel has determined that a common equity ratio of 38.5 percent is appropriate for FEI effective January 1, 2013.

The Commission Panel has examined the factors contributing to long-term risk in this proceeding and considered the submissions of each of the parties. The Panel has found that reductions are warranted in long-term risk associated with provincial government climate and energy policies as well as the competitive position of natural gas relative to electricity. Both of these risk areas were rated by the FBCU as category 2 risks. To offset these there is not a single area where the Panel has been persuaded the level of long-term risk has been demonstrated to have increased materially since 2009.

The Commission Panel notes that the 2009 Decision put considerable emphasis on the uncertainty created by climate change legislation that did not exist during the previous cost of capital proceeding. In addition, the 2009 Decision acknowledged the change in the competitive position of

natural gas versus electricity but concluded that there were too many variables at play for this to be considered permanent. The Panel's finding that there is lower long-term risk related to both of these factors since 2009 is indicative of a reduction in overall risk to FEI which needs to be reflected in the common equity ratio.

Consideration being given to both long and short-term risk, the Commission Panel determines that a reduction in the common equity ratio of 1.5 percent to 38.5 percent is appropriate.

Considering the discussion of optimal capital structure in Section 4.3, the Commission Panel notes that the reduction in common equity ratio to 38.5 percent is reflective of reduced long-term risk and yet balances this against potential disruption caused by a significant weakening of credit metrics.

With respect to credit ratings and metrics, the Commission Panel notes that considerable concern has been raised concerning FEI's credit metrics. In Section 4.4 we found the evidence supportive of maintaining an "A" category credit rating but not at all costs.

The Commission Panel notes that the 38.5 percent equity ratio awarded FBCU in this proceeding falls within the upper end of a range of comparative utilities in other Canadian jurisdictions and considers it to be reasonable on a comparative basis.

FEI is to file within 30 days of this Decision and the accompanying Order G-75-13 a document setting out how and when it will implement the change to its capital structure.

5.0 RETURN ON EQUITY

5.1 Key Issues

The Commission Panel is of the view that an important consideration in this proceeding is the determination of a return that provides investors with the opportunity cost of their investments. The Brattle Report recognizes and elaborates on this fundamental principle:

“[The cost of capital is] Defined as *the expected rate of return in capital markets on alternative investments of equivalent risk*, it is the expected rate of return investors require based on the risk-return alternatives available in competitive capital markets. Stated differently, the cost of capital is a type of opportunity cost: . . .” (Exhibit A2-3, pp. 2-3)

However, even if one accepts the concept of the opportunity cost as a foundation of a Return on Equity determination, a remaining challenge is that risk and expected return of the relevant ‘alternative investments of equivalent risk’ are in the eyes of investors who have access to well functioning capital markets. These expectations are not directly observable to Panel members or to parties in this proceeding who provide evidence for the Panel to consider. Instead, estimates of investors’ expectations are based on data that are interpreted through *models* of competitive capital markets. The Panel finds an observation offered in the Brattle Report to be instructive:

“It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured.” (Exhibit A2-3, pp. 3, 5-6)

The evidence presented to the Panel was based on a large variety of specific models that fall into four broad classes: (i) DCF models; (ii) CAPM (iii) ERP models and (iv) CE models. Within these four classes are numerous specific implementations that vary in structure, assumptions, and the data from which they were estimated. For instance, there are multiple DCF models with multiple estimates of the appropriate opportunity cost of an equity investment in the Benchmark Utility FEI. The estimates of the investor’s opportunity cost of equity, summarized in Appendix F to this Decision, range from 6.15 percent (Dr. Safir CAPM) to 11.50 percent (Dr. Vander Weide’s FRP model).

The models and approaches used by the expert witnesses in this proceeding to estimate the ROE are summarized in Tables included in Appendix F of this Decision.

The key issue then in the determination of the appropriate ROE is assessing how much weight to give to each of these models and their estimates. In turn, the weight given to each estimate depends on a judgment of the validity of the conceptual base of the four broad model classes and a judgment of how reasonable the model inputs are. The Panel has based this judgment, as much as possible, on the objective of determining the opportunity cost of equity.

The Panel finds that the two most compelling frameworks for assessing the cost of equity are the DCF model and the CAPM. These models have well understood theoretical bases and explicitly recognize the opportunity cost of capital. Accordingly, these two models are given equal weight in determining the allowed ROE. As discussed in Sections 5.4 and 5.5, the ERP models (with the exception of Ms. McShane's CAPM based equity risk premium) and comparable earnings model are not based on compelling foundations. Furthermore, model inputs and estimates are largely *ad hoc* and assessments of the validity of these inputs and estimates are based on subjective evaluations with minimal logical guidance. Consequently, both the ERP and CE approaches are given no weight in the Panel's determination of the appropriate ROE for the benchmark utility.

5.2 The Capital Asset Pricing Model

The CAPM is based on consideration of individual investors making portfolio decisions in a well functioning capital market. As such, it is a model of the shareholders who own the shares of the firm. Of all the models used to present evidence to the Panel, we consider that the CAPM provides the underpinnings of investor choice in greatest detail.

The CAPM is based on portfolio theory, a theory that answers the question: If an investor wishes to achieve a particular rate of return and is able to invest in a large set of securities, what investment strategy will deliver the target expected return at lowest possible risk? (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 78) The somewhat surprising answer given by portfolio theory is that all investors will hold a combination of two mutual funds; one made up of all risky securities available, referred to as 'the market portfolio' and the second made up of risk free securities. In contrast to intuition, individual risk aversion will not determine which specific securities to invest in but will

determine how much of an investor's wealth will go in the market portfolio and how much will go into risk-free securities. A more risk-averse individual will hold less of their wealth in the market portfolio and more in treasury bills than a less risk-averse individual.

The result that investors will hold well diversified portfolios instead of individual stocks provides great guidance in elaborating on the seminal Supreme Court of Canada decision of *Northwestern Utilities* that the allowed return on capital is to be comparable to the return that would be earned on "... the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise." (Exhibit A2-3, p. 2) The CAPM tells us that these 'other securities' are not other comparable firms but are instead comparable portfolios that combine the market and the risk free rate.

The Commission Panel notes that the reason investors are better off holding a mutual fund instead of picking individual stocks is diversification. Diversification builds on another bit of intuition: don't put all your eggs in one basket. As The Brattle Report states:

"...when security returns are positively correlated (i.e., have a tendency to move in the same direction, to some degree), trade in capital markets allows investors to reduce their total risk exposure by holding portfolios, which serve to diversify the risk of the individual securities. Diversification permits investors to obtain lower variance for a given expected return or a higher expected return for a given level of variance, where variance of returns over time is a measure of risk."
(Exhibit A2-3, pp. 6-7)

Since diversification is a driving force in investor's decisions, leading them to hold broadly diversified portfolios, when they consider the value of an individual stock they do not consider the total risk of the stock in isolation. They instead consider the amount of risk the stock will add to the risk of the mutual fund, recognizing the effect the stock has on the total diversification achieved. The amount of risk that remains after the benefits of diversification is referred to as non-diversifiable or systematic risk. The measure of the systematic risk is called beta. (Exhibit A2-3, pp. 6-7; Exhibit C4-9, p. 9; Exhibit B1-9-6, Appendix F, p. 88)

The CAPM builds on portfolio theory by providing a risk return relationship that recognizes beta as the risk measure. The theoretical foundation and the formulation of the CAPM is discussed in the evidence of Dr. Safir (Exhibit C4-9, pp. 8-11) and in the Brattle Report, which states:

“The presence of a market underlies the “opportunity cost” interpretation of cost of capital – by investing in a security A, an investor foregoes (some) investment in an alternative, “comparable risk,” investment B obtainable through the market.” (Exhibit A2-3, p. 6)

The opportunity cost of an investment is based on the return on a risk free investment, which is the risk free rate. To this is added a ‘risk premium’. In turn there are two parts to the risk premium. The first is the extra return that would be earned by holding the market portfolio on its own instead of the risk free security. The expected return on the market is denoted r_m and the risk premium over the risk free return, r_f , is denoted by $(r_m - r_f)$. This is referred to as the ‘the market price of risk’ or the ‘market risk premium’. The second component of the risk adjustment is beta which adjusts the market risk premium to account for the degree to which the individual stock contributes to the market risk; low beta stocks contribute less than average and earn less than the market rate, high beta stocks earn more.

The advantage of the CAPM is that it distils the complex interactions among risk averse investors trading with each other to a simple equation with three parts:

$$r_e = r_f + (r_m - r_f)\beta$$

where r_e is the opportunity cost of equity.

So, to estimate the investor’s opportunity cost requires an estimate of the risk free return, the market risk premium and the beta. In spite of the CAPM’s strong theoretical underpinnings, the estimation of these model inputs presents challenges as outlined in the Brattle Report (Exhibit A2-6, pp. 16-25) and in the evidence of Ms. McShane. (Exhibit B1-9-6, Appendix F, pp. 67-70) The challenges include the role to be played by the US data in the analysis.

The Panel recognizes the growing importance of US and indeed global securities in the portfolios of Canadian investors as pointed out in the evidence of Mr. Engen and of Ms. McShane. (Exhibit B1-9-6, Appendix E, pp. 11, 43-50; Appendix F, pp. A-14, A-15) The Panel also recognizes that none of the evidence was based on data related to global portfolios held by investors; for instance, market portfolios were defined as either the Canadian or US market separately and none of the evidence dealt with an integrated global portfolio. Furthermore, currency risk was not considered nor was the magnitude of foreign ownership of FEI. The evidence presented includes CAPM estimates on either US or Canadian data. In light of these concerns with respect to the lack of a complete global

perspective and the potential for risk (including currency risk), the Panel concludes that the more appropriate of these two perspectives is that of the Canadian based CAPM. Therefore, the Panel places greater weight on Canadian based CAPM estimates.

The Panel received a great deal of evidence on various estimates of the following three inputs.

(1) The Risk Free Rate, r_f

Evidence submitted to the Panel indicates that, at the time of filing, returns available to Canadian investors on long-term Government of Canada default free bonds were in the 2.6 to 3 percent range. (Exhibit B1-9-6, Appendix F, p. 77; Exhibit C6-12, pp. 53-71) Although this return was available to investors and therefore seems to meet the requirement of an opportunity cost, all of the experts submit that the appropriate opportunity cost is better measured by the *forecasted* yield on a long-term risk free instrument and that in some cases even this estimate should be adjusted.

Estimates of the risk free return available to investors, based on forecasted long-term Government of Canada Bond Yields, range from a low of 2.95 percent estimated by Dr. Vander Weide (Exhibit B1-9-6, Vander Weide Evidence Appendix G, p. 35) to a high of 4.0 percent by Ms. McShane and Dr. Safir. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 77; Exhibit C4-11, BCUC 1.4.1) Dr. Booth submitted that 3.0 percent was the forecasted yield on long-term Government of Canada Bonds but he considers forecast long Canada bond yields of 3.0 percent to be “well below any ‘equilibrium’ yield since they are only 1% above the forecast inflation rate and mean locking in a negative real yield for a typical taxable investor.” (Exhibit C6-12, p. 60) Dr. Booth testified in cross-examination that:

“...we do have foreign official flows of money coming into Canada because we are a triple A rate country and they are basically buying Canadian government bonds, pushing up prices, pushing down yields, and pushing them down to a value that I do not think reflects the proper trade-off between risk and return by “an ordinary private investor” making these decisions.” (T8:1516)

Accordingly, Dr. Booth adds 0.8 percent to the 3 percent to recognize the alternative, and to arrive at his “Base adjusted LTC forecast” of 3.8 percent. (Exhibit C6-12, pp. 84-85, 93; Exhibit C6-15, BCUC 1.30.3)

In summary, the evidence presented seems consistent in stating that the current rates available on risk free government securities is between 2.6 percent and 3 percent. However, the Panel also agrees with the experts that current monetary policy is historically unusual and subsequently results in the possibility of a higher effective risk free rate. **Therefore, the Panel determines that the estimate of 3.8 percent for the risk free rate is reasonable, corresponds to Dr. Booth's estimate, and is within the relatively narrow range of estimates presented by all experts.**

(2) Market Risk Premium ($r_m - r_f$)

Estimates of the market risk premium range from 5 percent to 6 percent according to Dr. Booth (Exhibit C6-12, Appendix B, p. 16) to a high of 7.5 percent submitted by Ms. McShane. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 98) The basic estimation methodologies used by all experts were similar in that they were based on historical data on market returns and returns on risk free securities. They differ in some important details.

Ms. McShane bases her estimate on the average return on an investment in the market and shows, in Table 10, page 80 of her evidence that the average return on equities in Canada over the 1924-2011 period is 11.4 percent. From this number, Ms. McShane subtracts the *current* forecasted long-term Government of Canada Bond yield of 4 percent to arrive at her 7.5 percent estimate of the risk premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 87) The Commission Panel understands that it is typical to base the risk premium on the average historical difference between the return on the market and the risk free rate. It is our understanding that this approach is to deal with, among other things, the fact that historical market returns and historical bond yields reflect historical inflation while current returns reflect current inflationary expectations. This is an especially important consideration in the current environment where inflationary expectations are at a historically low level. (T3:483-485; T5:713-715)

To illustrate our concern with the approach used by Ms. McShane, the Commission Panel notes that there are times in the last 30 years where this approach would have yielded a very small or even negative risk premium. For instance, Schedule 2 of Ms. McShane's evidence reports that the yield on Long-term Canadian Government bonds in 1990 was 10.69 percent. If this was subtracted from the average market return it would have yielded an unreasonably low market premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, Schedule 2, p. 1; T8:716-717)

Ms. McShane was asked if she could provide a single reference to a textbook or Journal article that advocated using her approach. Her response was that she 'probably could not' (T5:717-718). Accordingly, the Panel gives no weight to the risk premium estimate of 7.5 percent provided by Ms. McShane.

Dr. Booth provides evidence that the historical risk premium is between 5 percent and 6 percent. He adjusts this range for 'Operation Twist' to obtain a risk premium estimate of 5.8 percent to 6.8 percent with a midpoint of 6.3 percent. (Exhibit C6-12, p. 93) Operation Twist refers to monetary policy intended to influence returns at various maturities including long maturities.

Dr. Booth provides two tests of the robustness of his estimate. One robustness test is to compare his estimate of the market risk premium with expectations used by FEI in assessing its defined benefit pension liability. Dr. Booth takes the expectation of market return of 7 percent, provided by FEI's consultants, and converts this geometric return to an arithmetic return. From this, Dr. Booth infers that FEI has, for purposes of valuing its pension liability, accepted an expected market return of 9 percent. Based on this he concludes, on page 93 of his evidence, that "[a]s a result, FEI's data seems consistent with a market risk premium of about 6.2%." In their Final Submission, FBCU submit that the Panel should not rely on data used in assessing pension liabilities. FBCU assert that, since actuaries provided the data, they naturally reflect a conservative bias. FBCU cited its witness Ms. McShane, who stated that pension fund managers and actuaries "... have absolutely no incentive to be anything but very conservative because they have a lot on the line. A pension fund needs to be able to assure that it has funds available to pay its retirees." (FBCU Final Submission, p. 151)

The Panel does not accept the assertion that the actuarial expectations are conservatively biased and should be rejected. Actuaries are charged with fairly assessing pension plan liabilities. The Panel finds, therefore, that this robustness test is indeed helpful in assessing the risk premium.

In a second robustness test, Dr. Booth uses the DCF model to estimate an expected return on the entire market. The resulting estimate is 9.3 percent and Dr. Booth notes that this is very close to the expectation held by FEI's own actuaries. (Exhibit C6-12, Booth Evidence, p. 86) This is a forward looking estimate of the market return so that a forward looking risk free investment can be used to compute the risk premium. Since Dr. Booth concludes in his first robustness test that a 9 percent

market return implies a 6.2 percent risk premium, his estimates of 9.3 percent for the market suggests a market risk premium of about 6.5 percent.

FBCU argue that the DCF cannot be used to assess the market as a whole. (FBCU Reply, pp. 29-30) The Panel disagrees with this assertion. Although the model is typically illustrated and applied to a single company, the logic of investors setting prices based on expected cash flows applies equally to a mutual fund or portfolio of shares. The Panel, therefore, does not agree that this approach cannot be taken to estimate the expected return on the market. The Panel therefore finds the DCF based estimate of forward-looking market returns to be helpful as a check.

Other estimates of the risk premium were also in the range of 5.96 percent (Dr. Safir's Canadian estimate, Exhibit C4-9, p. 12, Table 1) to 6.6 percent. (Dr. Vander Weide's estimate, Exhibit B1-9-6, Appendix G, p. 38) **Given the preceding discussion, the Commission Panel accepts a market risk premium of 6.4 percent as it is within reasonable forecasts presented.**

(3) Betas

Evidence on the beta estimates is largely based on a standard approach of regressing returns from comparable firms on market returns. Since FEI does not have traded equity, estimates of beta must be based on comparable firms. In the evidence submitted, the set of comparable firms include Canadian firms as well as, in some cases, US-based firms.

Dr. Vander Weide submits a beta estimate of 0.92 based on the historical ratio of the average utility risk premium to the S&P risk premium. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 42) Aside from the fact that this is a beta estimate for US Utilities (T6:1092), the method differs significantly from the more commonly accepted method(s) of calculating a beta estimate as set out in the Brattle Report (Exhibit A2-3, pp. 15-16), and as calculated by the other witnesses in the proceeding. Accordingly, the Panel places no weight on this beta estimate.

The other beta estimates submitted range from a low of .36 by Dr. Safir for his Canadian CAPM estimate (Exhibit C4-9, pp. 12, 15), to a high of 0.65-0.70 by Ms. McShane. (Exhibit B1-9-6, pp. 97-98) Dr. Booth provides an intermediate estimate of 0.45-0.55. (Exhibit C6-12, Appendix C, p. 14) All

estimates begin with a regression of returns of the comparator firm on market returns with the 'raw beta' being the slope coefficient of the regression.

The differences among estimates largely result from adjustments that are made to the raw betas. Empirical evidence indicates that the regression based beta estimates seem to understate the betas of low risk firms and overstate the betas of high risk firms. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 96; Appendix A to Ms. McShane's Evidence, pp. A-21-26; Exhibit B1-9-6, Appendix G, p. 41) Since, by construction, the beta of the market is one, the adjustments are intended to bring the estimated beta's closer to one. To accomplish this, Ms. McShane contends that it is appropriate to adjust utility betas towards the market average of 1.0. (Exhibit B-19-6, McShane Evidence, Appendix F, p. 96) Both Dr. Booth and Dr. Safir, on the other hand, contend that the adjustment should be to the utility average beta that is in the range of 0.5 - 0.6. (Exhibit C6-12, Booth Evidence, p. 71; Exhibit C4-9, Safir Evidence, p. 15)

None of the evidence presented revealed the actual bias in beta estimates; instead the experts assert a particular adjustment. In cross-examination Ms. McShane acknowledges that utility betas may indeed not trend towards one.

Mr. HOBBS: And because regulation protects companies, isn't it also true that you would not expect betas for utilities to ever trend towards 1?

Ms. McSHANE: To trend towards 1. I guess I don't disagree with that. I never said that they would. (T4:549)

Similarly, in cross-examination at T6:1073, Dr. Vander Weide says:

DR. VANDER WEIDE: Yes. And I readily recognize that betas for utilities don't adjust toward 1.0.

In their Reply, FBCU argued:

"Ms. McShane's relative risk adjustment of 0.65-0.70 for a benchmark utility, based partly on adjusted betas, recognizes the past relationship between utility returns, both in Canada and the U.S., and the returns on the equity market as a whole. Over the longer-term, utility investors have achieved risk premiums that have been significantly higher than 45% to 55% of the risk premiums achieved on the equity market portfolio. That experience is consistent with the empirical evidence that lower (higher) beta stocks generally have achieved higher (lower)

returns than the CAPM and beta would have predicted. It is not logical to conclude that, based on that experience, utility investors now only expect to achieve an equity risk premium that is 45% to 55% of the equity market risk premium (or Dr. Safir's lower 36%) simply because utility share price movements have not exhibited a high degree of correlation with price movements in the overall equity market." (FBCU Reply, p. 35)

An adjustment of beta to the market average of one seems inconsistent with the lower risk in the industry, while realized return seems to indicate a beta that exceeds the industry average. The Panel finds that none of the positions fully explain the beta value and therefore accepts an intermediate beta estimate of 0.6 representing the range of reasonable estimates presented.

5.2.1 Adjustments to the CAPM

A number of experts raised concerns about the validity of the simple 'single factor' CAPM. The term single factor refers to the reliance of the prediction of the model on only the market portfolio, the factor implied by the theory. Ms. Ahern introduced in evidence a summary article that shows how other factors such as firm market capitalization (size) and market-to-book ratios can provide added explanatory power to the single factor CAPM. (Exhibit B2-7, Evidence of Ms. Ahern, pp. 13-14; Exhibit B2-7, Attachment PMA-1, Exhibit PMA-9)

The CAPM is by far the most widely studied asset-pricing model and it is not surprising that more is known about its empirical performance than other asset pricing models. This evidence also implies that improved performance can be achieved by including these well-studied extensions of the model. The Panel notes, however, that none of the experts relied on the extensions as found in the literature findings in dealing with the shortcomings of the single factor CAPM. (Ms. McShane, T5:720-722); Dr. Vander Weide, T6:1102-1108; Dr. Safir, T7:1259-1262; Ms. Ahern, T7:1355-1357; Dr. Booth, T8:1658-1663) Instead, the evidence presented by different experts responded to the relatively poor empirical performance of the CAPM in a number of *ad hoc* ways.

Dr. Vander Weide's response to the weak empirical performance of the CAPM is to place no weight on CAPM estimates even though he provides estimates himself. In cross-examination, however, Dr. Vander Weide testified that he did not attempt any standard adjustments to the CAPM that might improve performance. For instance, he did not adjust for the importance of international markets to Canadians, he did not adjust for changes in capital structure and he did not study the ability of a

multi factor model to capture returns. (T6:1108-1111) As a result, the Panel does not accept Dr. Vander Weide's response to the relatively poor performance of the CAPM and continues to place weight on the model.

Ms. McShane and Dr. Booth both attempt to improve the performance of the CAPM by adding empirical analysis in order to augment the basic model. Dr. Booth is clearest in his objective when he states: "I regard this sort of adjustment as converting the CAPM into a conditional CAPM where the CAPM holds conditional upon the state of the financial markets." (Exhibit C6-12, p. 81)

Dr. Booth testified that an academic literature exists that supports the analysis of a conditional risk premium and his credit spread adjustment is consistent with that literature. (T8:1659)

Ms. McShane does not provide the same link to the academic literature and acknowledged, in cross-examination, that her work is along the lines of a multi factor CAPM. (T5:718-720)

The Commission Panel appreciates the efforts of the experts to recognize and deal with the shortcoming of the single factor CAPM. The evidence suggests there are two main thrusts to this effort: i) improving the estimate of the risk premium by conditioning on the current state of the capital markets; and ii) improving estimates of the risk return relationship by adding the factors to the single factor CAPM. Notwithstanding the efforts, the Commission Panel finds that we are not able to assess the validity of the extensions to the single factor CAPM that were presented as there is insufficient evidence involving the use of multi-factor models in this proceeding. The experts expressed reluctance to include other potential extensions to the CAPM that they thought were too complex. This is further addressed in Section 8.

In this regard, the Panel agrees more generally with the specific concern of ICG who argues that in Ms. McShane's CAPM based ERP, she "...makes an adjustment to the market risk premium of approximately 100-150 basis points because in her opinion market risk premium are in fact correlated with the risk free rate." ICG cites Dr. Safir as characterizing the adjustment as arbitrary and not in keeping with the CAPM model. ICG submits that before the Commission Panel accepts this adjustment there must be very strong evidence to support it. In the absence of such strong evidence, the CAPM specifications should not be changed. ICG goes on to say that: "The evidence regarding the correlation (inverse relationship) between the market risk premium and the risk free rate is in fact just that, it is a subjective judgement, with at best, very limited evidence in support of Ms. McShane's proposed departure from the CAPM model." (ICG Final Submission, p. 19)

In support of its argument that there is limited evidence in support of Ms. McShane's adjustment ICG submits that her evidence in support of a relationship between the market risk premium and the risk free rate is presented on a cumulative basis. It argues that when the same data is provided on a non-cumulative basis the US risk premiums do not follow income returns in the manner she suggests (Exhibit B1-53, Undertaking No. 14) and in some instances the data support the opposite conclusion to that observed by Ms. McShane.

Rather than relate the models presented in this hearing to the academic literature, as presented by Ms. Ahern for instance, the extensions seem to be somewhat *ad hoc* leading to the sort of concerns raised by ICG. There is no evidence, therefore that the models present were not the result of a "fishing expedition." That is, the Panel does not know if other adjustments or specifications would produce different results and we cannot assess whether other non-reported specifications should logically be ignored. In the absence of persuasive evidence that these are of value, the Panel is content to consider simple single factor models. At this time the Panel is not persuaded that the specific model extensions that are presented are valid and hence places no weight on them. However, the Panel recommends that in the future improvements in the model can also be brought into evidence, but the evidence should then include both the model extensions as well as a basis on which to judge the validity of the extensions.

5.2.2 CAPM Based Estimate of ROE

Summarizing the discussion above, the Commission Panel has applied the required judgment and accepts the CAPM estimate at 7.64 percent. This reflects a risk free rate of 3.8 percent, a risk premium of 6.4 percent, and a beta of 0.6.

5.3 Discounted Cash Flow Approach

The basis of the DCF approach is the principle that in a competitive market investors who purchase securities are essentially bidding for expected future cash flows that the security entitles them to. Competition implies that investors search for 'good deals', ones that offer the lowest price for a particular cash flow of a particular risk. The higher the price paid, the lower the expected return, so, in an attempt to improve their lot, investors search for securities that trade at a low price generating a high expected return. In their quest for high returns, they are willing to pay a price up to a level

that would make the purchase at least as good as the next best alternative, i.e. equal to their opportunity cost. Of course, in a competitive market, other investors are also looking for good deals and, as a result, competition ensures that observed prices generate returns equal to the opportunity cost.

The theory implies that if one can observe prices and expected cash flows one can infer the investor's opportunity cost. The DCF model applies this logic to equity investment in order to infer the opportunity cost of equity. It is assumed that cash flows to investors consist of dividends and that stock prices reflect investors' expected dividends and the opportunity cost of the investment. If we observe prices of equity and estimate all future dividends that the equity gives title to, then one can infer the opportunity cost of equity. (Exhibit A2-3, pp. 26-29; Exhibit B1-9-6, McShane Evidence, Appendix F, Appendix C, p. C-1)

An attractive feature of the DCF model is that it assumes, unlike the CAPM, that investors hold realistic investment horizons; both short and long-term investors estimate all dividends that the firm will provide over its lifetime. As with the CAPM, a significant disadvantage to the Commission is that for FEI none of the inputs, for example, price, dividends, or opportunity cost, are directly observable. The equity of the benchmark utility is held by Fortis Inc. and not actively traded. Therefore, future dividends are in the eye of the beholder as is the opportunity cost of capital. As a result, the opportunity cost estimate rests entirely on inferences that are commonly based on comparable firms. Not only should these firms be comparable, they should also have actively traded equity, and a source for estimating expected dividends.

Simplifying assumptions make the task of estimating dividends easier and the evidence submitted was all based on one of two simplifications or models. The 'Perpetual Constant Growth' model assumes that investors estimate the next dividend to be paid by the company and a single rate at which dividends will grow in perpetuity. The validity of the constant growth model is reduced when the estimated growth rate comes close to the opportunity cost (as this implies an extremely large stock price) and the model is invalid if the expected growth rate is greater than or equal to the opportunity cost of equity. The second model, 'the multi-stage growth' model, also requires an estimate of the next dividend to be paid but then allows investors to see multiple stages of constant growth; for example, the investor might expect growth of 4 percent for the next five years, 3 percent for the 5 years after that, followed by a constant perpetual growth rate of 2 percent starting

11 years hence. Although the long-term perpetual growth stage must meet the same growth restrictions as the constant growth model, the earlier stages are not restricted in this way. Therefore, multi stage growth models allow considerable more flexibility in dealing with growth forecasts. The Commission Panel has considered DCF-based ROE estimates presented by Ms. McShane, Dr. Vander Weide, and Dr. Safir.⁶ Dr. Booth's DCF estimate for the market as a whole was used as a check on his CAPM estimate and is discussed with that estimate previously in Section 5.2.

1) Ms. McShane's estimates

Ms. McShane provides five different estimates with ROE estimates based on the DCF model. The estimates range from 8.6 percent to 11 percent. The estimates were variously based on 12 US Utilities or 5 Canadian utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 113) FBCU submit that: "The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.1% to 9.8% (mid-point of approximately 9.4%)." (FBCU Final Submission, pp. 105-107) The FBCU also point out that Ms. McShane relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations, minimizing the need to superimpose on the analysis her own subjective view of growth expectations. (FBCU Final Submission, p. 106) Ms. McShane recognizes, however, that the forecast period for analysts' long-range earnings and dividend forecasts is typically three to five years over a business cycle (Exhibit B1-9-6, Appendix F, Appendix C, p. C-4), and that extending these forecasts into perpetuity in the constant growth model can overstate expected return. (T4:664-665)

2) Dr. Vander Weide's estimates

Dr. Vander Weide only presents evidence based on a constant growth DCF and only for a sample of US Firms. He relies on I/B/E/S Thomson Reuters Mean Growth forecasts to estimate dividend growth. Dr. Vander Weide's application of the DCF model to his comprehensive group of utilities produced a result of 10.3 percent, and to his smaller group of utilities, 10.0 percent, including 0.50 percent for flotation costs. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, pp. 27-31; Exhibits

⁶ Dr. Booth employed a Constant Growth model but only to estimate the market wide expected return. This was used as a check on his CAPM estimate and so is not included in this discussion.

6 and 7 of his evidence) The FBCU submit that "...Dr. Vander Weide's DCF estimates are reasonable and should be given significant weight." (FBCU Final Submission, p. 108)

3) Dr. Safir's estimates

Dr. Safir uses a two stage DCF model to develop two estimates; one of 8.99 percent based on 5 Canadian firms and one of 8.86 percent based on a sample of 18 US utilities, before adding flotation costs amounting to 5 percent of the initial ROE estimates. (Exhibit C4-9, pp. 24-26, and Schedules 3 and 4)

Commission Panel Discussion

The Brattle Report observes: "The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence unlikely to correspond to reality." Elsewhere the report is more specific: "The major source of debate for the DCF model is determining the dividend growth rate, particularly for the long-term. There is generally no publicly available data on forecast growth rates for periods longer than 5 years." (Exhibit A2-3, p. 30)

The FBCU urges the Panel to give the DCF considerable weight, while the AMPC/CEC submits that "a DCF analysis can provide a helpful "check" on CAPM estimates, but the Commission should be cautious not to rely too heavily on it." (FBCU Final Submission, p. 89; AMPC/CEC Final Submission, p. 41)

The Commission Panel is of the view that, notwithstanding the concerns expressed about the approach, considerable weight should be given to the DCF but also accepts that caution should be used in assessing the growth estimates presented. A number of specific concerns arise with respect to the evidence presented:

a) Reliance on analysts' short-term forecasts as the long run forecasts in constant growth formulas:

This reliance appears in the single stage models presented by Ms. McShane and Dr. Vander Weide. For instance, Ms. McShane's estimate based on Canadian comparable firms assumes perpetual dividend growth of 7.5 percent. Since this is larger than her estimate for long run GDP growth of 4.3 percent, Ms. McShane seems to imply that FEI will grow to be an increasingly larger segment of the economy. This is inconsistent with the evidence presented in Appendix F of her testimony where she enumerates many reasons why consumers, both residential and commercial, will migrate from natural gas to other sources. Similarly, Dr. Vander Weide's estimates of the cost of capital use short-term analysts' forecasts to estimate the constant growth model. Similar to Ms. McShane, the resulting implication is that FEI will become a larger component of the economy over time, a conclusion that seems inconsistent with FEI's submissions regarding a shrinking market share and falling customer capture rates. (FBCU Final Submission, p. 53) We also note that Dr. Vander Weide included firms whose growth rate exceeded his estimate of the cost of equity in his comparable firms. As noted above, such a growth rate is inconsistent with the DCF constant growth model yet were included in his sample without adjustment. This calls into question the DCF estimates presented by Dr. Vander Weide.

The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages.

b) Reliance on comparable firms operating in the US:

The AMPC/CEC submits that the use of US based comparable firms renders DCF estimates of limited value. In their submission, AMPC/CEC cites Dr. Booth as follows:

"[In the past] we had lots of pure play utilities in Canada, where you could do a DCF. In particular, all the local telephone companies were still regulated by the CRTC on a rate of return rate based method, and we had Island Telephone traded, Maritime Tel traded, NewTel traded, Bruncor Traded, Bell Canada traded, B.C. Tel traded. So we had a lot of traded rate of return regulated utilities that we could actually do DCF tests on. Unfortunately, they don't exist anymore." (T8:1493-1494)

While the Commission Panel concurs with the concern about comparability of US based firms, it also agrees with the argument of FBCU that, given the paucity of comparable Canadian firms, also recognized by Dr. Booth, augmenting Canadian data with US firms is appropriate. (FBCU Final Submission, p. 94) The Panel also recognizes the need for careful informed judgment in adjusting the US based estimates to reflect differences in the respective environments.

c) Analysts' forecast bias:

Given the heavy reliance on the forecasts of equity analysts, the AMPC/CEC submit that analyst bias may inflate DCF ROE estimates. (AMPC/CEC Final Submission, p. 59) FBCU argues that analysts' forecasts for utilities are not biased. (FBCU Final Submission, p. 111) The Brattle Report notes that studies have shown that analysts' forecasts are likely to be more accurate in utilities than in other sectors and bias is likely to be less in utilities than other sectors. (Exhibit A2-3, pp. 28-29)

The Panel finds that there is reason to be cautious of potential analyst bias in the utility sector. The expert testimony at this time does not, however, convince the Panel that an adjustment for analyst bias should be made. The Panel expects that future hearings will be informed of the latest research on bias in the analyst's reports on the utility sector.

Overall Assessment

The Commission Panel finds that the constant growth DCF models presented have growth assumptions that render the estimates questionable given the discussion above. Therefore, we place little weight on the submitted estimates that are based on the constant growth DCF. The estimates that the Panel found most helpful are Ms. McShane's multi-stage estimates in the range of 8.6 percent to 9.2 percent and Dr. Safir's estimates of 8.86 percent to 8.99 percent (two-stage). (Appendix F) Applying the appropriate judgment required, **the Commission Panel accepts an 8.9 percent DCF based estimate of the opportunity cost of equity.**

5.4 Equity Risk Premium Models

5.4.1 Introduction

FBCU's witnesses Ms. McShane and Dr. Vander Weide each provided results from various models, classified as equity risk premium models. Ms. McShane provided the results of three different 'types' of ERP models, comprising numerous estimates. Dr. Vander Weide used two types of ERP models, which he termed "Ex-Ante" and "Ex-Post" risk premium tests, and used two different samples for each of the two types of tests. None of the other witnesses relied on the ERP.

The Brattle Report summarizes the form and some of the issues concerning ERP models. According to the report, the ERP is frequently implemented using either a historical estimate of the risk premium or a forward-looking or expected risk premium. It notes that the historical risk premium is commonly estimated as the historical spread between equity and debt returns, so the primary choices for the analyst become which equity returns and debt instrument to use as well as the sample period over which the estimate of the spread (i.e., the risk premium) is to be based. The Brattle Report states that it is important that the analysis is consistent in its choice of a debt instrument to determine the cost of debt and that used to determine the risk premium. It also notes that the realized risk premium is highly dependent on the time period over which it is estimated, so that choice is also important. (Exhibit A2-3, p. 31)

The Brattle Report states that the forward-looking model requires that the analyst determine a proper measure of the cost of debt and how to estimate the expected risk premium. It says that because the yield to maturity of an investment grade bond serves as a proxy for the expected return, yield to maturity measures are natural candidates for the expected bond cost. However, determining the expected equity return is more difficult and requires the reliance on an estimation technique. It notes that it is common to rely on DCF models to determine the risk premium in the forward-looking version of the model. (Exhibit A2-3, pp. 31-32)

5.4.2 Discussion of the ERP Method and Results

The Brattle Report states that the risk premium model is a derivative of the CAPM so the comments that apply to the CAPM also apply to the Risk Premium Model, but that "...the Risk Premium Model

does not have the same level of theoretical support. The tie between theory and implementation is weakened because the interest rate in the Risk Premium Model is not necessarily equal to the risk-free rate and the risk premium is not explicitly based upon the product of the investment's beta and the MRP." (Exhibit A2-3, p. 33) Moreover, there is a concern that the historical risk premium approach to the ERP assumes that a historically realized risk premium is an appropriate measure for expected returns, but that over any given period, especially short periods, realized returns can differ substantially from expected returns. (Exhibit A2-3, p. 31)

A strength of the model identified in the Brattle Report is that the information on which the model relies is auditable. However, it notes that because inflation and other factors that are not directly related to the cost of equity capital may affect bond yields, the model will not necessarily produce like results for like conditions. It further states that the implementation of the model largely determines its ability to capture the systematic risk of companies, noting that, unless a forecasted return for relevant companies is used, the model will be unable to estimate reliably the cost of capital across different economic conditions. (Exhibit A2-3, pp. 34)

Commission Determination

The purpose of a rate of return model is to provide structure to the discussion of 'what a fair rate of return is.' Models used to assess this question provide structure and clarity and, in turn, a basis for the data to consider the appropriate interpretation to give it and the estimates.

The lack of a strong theoretical footing for ERP, as noted in the Brattle Report, may explain the large number of ERP estimates submitted to the Panel and the potentially intractable discussion of the merits of the models. There is simply little to help focus the analysis and as a result many models can be submitted as 'true' even though there is little on which to judge the validity of the submission.

The large number of estimates along with the absence of a compelling framework raises the following reservations about the estimates and indeed about the entire approach:

1. The models combine elements of the CAPM and the DCF with other ad hoc adjustments. Since evidence was presented on both the CAPM and DCF, it is not clear what is added by looking at these alternatives.

2. While it is not clear what is gained through these ERP models, it is clear that clarity is lost. In particular, the assumptions used in various estimates are difficult to evaluate. Ms. McShane, for instance, uses return estimates based on a sample of US firms with the 30-year Canada Bond rate in some estimates of the risk premium but in others uses 30-year A-rated utility/government bond yield spreads. (Exhibit B1-9-6, Appendix F, p. 99) Similar ad hoc assumptions are also found in Dr. Vander Weide's analysis. For instance, AMPC/CEC point to Exhibit C6-21 to demonstrate that if bond returns rather than bond yields were used in the analysis, the average Ex-Post risk premium for utilities would be approximately 4.47 percent or 2.3 percent less than Dr. Vander Wiede's estimate. Consequently, the AMPC/CEC argues that the Ex-Post estimates of Dr. Vander Weide must be ignored or if not ignored, then reduced by 2.3 percent. However, FBCU state that it is appropriate to use bond yields as the true risk-free rate. It is not clear, however, why the risk free rate is not estimated using a risk free return.

Again, while judgment is always needed to evaluate estimates, without a theoretical base, there is no consistent way in which these differences of opinion can be assessed.

3. Since the model variations are ad-hoc they are subject to the concern that they may be subject to a "fishing' expedition" criticism. In contrast, while we can obtain various results from the CAPM or DCF models by changing parameters such as the risk premium in the CAPM or the growth rate in the DCF, the reasonableness of the selected parameter can be questioned.

Given these concerns along with the fact that there is ample evidence on both CAPM and DCF based estimates, the Panel places no weight on the ERP estimates submitted.

5.5 Comparable Earnings Approach

The Brattle Report states notes that the CE method is one of the traditional approaches to the cost of capital estimation, but that it does not have a financial economics foundation or strong theoretical basis. The report states that the legal decision, *Federal Power Commission et al v. Hope Natural Gas Co.*,⁷ which stated that the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks, is often cited in the use of comparable earnings, but that neither the Canadian nor the US Supreme Courts has identified any specific methodology to determine a "fair return." (Exhibit A2-3, pp. 11, 36) The Commission Panel observes that much has been learned about financial economics since 1944. In particular, the notion of a comparable investment has been carefully cast in terms of investments in portfolios of

⁷ 320 U.S. 591 (1944); 64 S. Ct. 281; 88 L.Ed. 333 (1944) U.S. Lexis 1204

comparable risk since portfolios are more efficient in achieving any expected return than is a single security.

The CE method requires the use of a sample of unregulated companies as comparators, since the use of regulated companies to estimate the comparable cost of capital would be circular. The Brattle Report notes that because the comparable companies are unregulated entities, it is necessary to adjust for any risk differences between the sample companies and the target company, and because the estimates from the model do not come from regulated companies or activities, the method does not recognize the regulatory context in which the cost of capital is being applied. (Exhibit A2-3, pp. 35, 38)

The Brattle Report states that a major issue with the comparable earnings method is whether realized book returns are a good proxy for the return that investors expect going forward and notes that it is a backward looking measure with no consideration of current market conditions. (Exhibit A2-3, pp. 36-37)

Ms. McShane submits that the fair return standard "...is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained and the return allowed is comparable to the returns of enterprises of similar risk. The BCUC has recognized that the comparable return requirement is distinct from the capital attraction standard...." (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8) [emphasis in the original] In her view, the comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard and it is critical that the regulator recognize the comparable returns standard when setting a fair return. (Exhibit B1-9-6, Mc Shane Evidence, Appendix F, p. 114)

Ms. McShane submits that the comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values.

Ms. McShane arrived at her comparable earnings estimates based on the earnings on book-value of 21 unregulated Canadian companies from 2004-2011. (Exhibit B1-9-6, Appendix F, pp. 113-116) She arrives at the following result: "To recognize the unregulated companies' higher risk, a

downward adjustment of 125 to 150 bps to their returns on equity was made, resulting in a comparable earnings result in the range of 11.0% to 12.0%.” (Exhibit B1-9-6, Appendix F, p. 116)

To complete her comparable earnings estimate, she assesses the need for a market/book adjustment to the comparable earnings results. She submits that “[t]he similar to lower average market/book ratios of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicate no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies’ returns on equity due to their market/book ratios.” (Exhibit B1-9-6, pp. 116-17)

Dr. Booth submits that the average ROE increases when one starts adding low-risk firms to a comparable earnings sample and then progressively decreases as more risky firms are added, particularly after the lowest risk firms are added. He argues that: “...to get a high ROE from a sample of comparable earnings firms simply means coming up with “reasonable” screens to narrow down the sample and exclude those firms with significant losses. (Exhibit C6-12, p. 6)

He used book-value based estimates for Corporate Canada as a whole, using Statistics Canada reported earnings for the period 1987 to 2011 and the TSX composite for the same time period. He arrived at a CE estimate for the Canadian market of 9.3 percent, and says that “Like the overall stock market return this then needs to be lowered for the lower risk attached to regulated utilities.” (Exhibit C6-12, Appendix E, pp. 3, 7, Schedule 2)

Dr. Booth submits that CE “...is totally unreliable unless a market to book adjustment is made which is rarely the case.” (Exhibit C6-15, BCUC 1.39.0) He also submits that a “...market to book adjustment is needed since low risk firms usually have market power which is reflected in higher ROEs. It is incorrect to then allocate to a utility an ROE from a sample of firms that reflects market power when regulation is designed to remove this market power.” (Exhibit C6-15, BCUC 1.67.1)

Dr. Booth also says that a problem with looking at past ROEs is that they are earned on historic accounting book equity that does not reflect what can be earned on investments today. (Exhibit C6-12, Appendix E, p. 5)

The AMPC/CEC argues that the Commission should place little or no weight on the comparable earnings test. (AMPC/CEC Final Submission, pp. 38, 60)

Dr. Safir used two market-value based estimates: one for the same Canadian sample of 21 companies used by Ms. McShane; the other based on a sample of 31 US companies in the consumer goods, industrial goods or service sectors using the same sample selection criteria as Ms. McShane used for her Canadian sample. (Exhibit C4-9, pp. 28-29)

Dr. Safir calculated his comparable earnings estimates "...using net income and market value of equity...." He submits that because his comparable earnings estimates were calculated using market-based values instead of book value, they more accurately capture the conditions in the current capital markets in which the benchmark firm would be competing for capital. He goes on to say that his method accounts for factors such as inflation, since both the net income and the stock prices will reflect the level of inflation occurring at the time these numbers were reported and that "[b]ook value-based calculations of comparable earnings will not account for inflation." (Exhibit C4-9, p. 30) Using his market-value based method of calculating CE Dr. Safir arrived at estimates of 6.85 percent for his Canadian sample and 5.81 percent for his US sample. He submits that the Canadian estimate should be given twice the weight of his US estimate and arrives at a weighted average estimate of 6.50 percent. (Exhibit C4-9, p. 33)

Dr. Vander Weide did not provide a CE estimate.

Commission Determination

The fundamental issue regarding the CE test is its lack of a basis in financial economics. The approach requires a sample of unregulated companies of similar risk, but creating a sample of unregulated companies that are, and can be shown to be, of similar risk is difficult without a theoretical basis such as the CAPM or the DCF. Dr. Booth has pointed out the issues that arise when even 'reasonable' screens are used to eliminate companies from the entire universe of companies to create a sample. Moreover, the CE method is retrospective, whereas the ROE to be established for the benchmark utility is prospective.

In her evidence, Ms. McShane submits that: “The economic principle guiding the fair return is the opportunity cost principle.” She also submits that one of the requirements of the FRS is that the return allowed is comparable to the returns of enterprises of similar risk and that it is critical that the regulator recognize the comparable returns standard when setting a fair return. She also states that the CE test is an implementation of the comparable returns standard and is to be distinguished from the cost of attracting capital standard. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 2, 8, 114)

During cross-examination a discussion on whether the comparable earnings test reflects an investor’s opportunity cost concluded with the exchange below:

COMMISSIONER GIAMMARINO: But you would agree that in terms of an opportunity cost, it doesn’t match up that closely to what we would consider the exact opportunity cost to the investor.

Ms. McSHANE: A: No, it is not an opportunity cost in the same sense that you were talking about. (T5:732-35)

The Commission Panel addressed the FRS in Section 2 and recognized that a fair or reasonable overall return on capital should be comparable to the return available from the application of the invested capital to other investments of like risk (comparable investment requirement). However, the Commission does not accept that this requirement means that it must use the comparable earnings method as a means of determining what return is required to meet the FRS. Modern finance theory has clearly established that comparable risk is assessed relative to a *portfolio* rather than a single stock. This is indeed the basis of the CAPM and other extensions of risk return modules. Searching for individual firms of comparable risk is consistent with this only if the comparison recognizes non-diversifiable risk as the relevant characteristic. This is exactly what is done when CAPM comparators are sought. But this is ignored when companies are considered comparable on dimensions other than systematic risk.

The preceding discussion highlights some of the serious problems the comparable earnings method contains as a means of determining the return required to meet the FRS. **Consequently, the Commission Panel places no weight on the comparable earnings results.**

5.6 Allowance for Financing Flexibility

Ms. McShane described financing flexibility allowance as intended to cover three distinct aspects: (1) flotation costs comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the “fairness” principle (Exhibit B1-9-6, McShane Evidence, Appendix F, p. F-1). Flotation costs and financing flexibility adjustments are typically applied to the market-based cost of equity estimates, i.e., the CAPM and the DCF models.

Ms. McShane provided an allowance of 50 basis points for each of her market based tests in order to maintain the market value at a small premium to the book value. In the alternative, should the Commission rely only on the market-based tests, Ms. McShane proposed an allowance for financing flexibility at 1.0 percent. (Exhibit B1-20, BCUC 75.2.1)

Dr. Vander Weide provided an allowance of 50 basis points for flotation and financing flexibility. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 35)

Dr. Booth provided an allowance of 50 basis points, stating that the market opportunity cost should be adjusted upwards to include issuing costs or a financial flexibility adjustment to make sure that shares can always be sold to net out the original cost included in the rate base, which is all that earns the fair ROE. He also noted that most regulators in Canada have allowed 50 basis points for these new issue costs (Exhibit C6-12, p. 8).

Dr. Safir referred to a survey of flotation costs, which determined them to be approximately 4.5 percent of the recommended rate of return. Based on the 4.5 percent, Dr. Safir applied 5 percent of the rate of return, an equivalent of around 32 to 40 basis points for his CAPM models and 47 bps for his DCF model, to reflect the marginally higher costs that would be faced by Canadian issuers either crossing the border to utilize the US market or in issuing in the smaller Canadian capital market. (Exhibit C4-9, pp. 16-18)

Commission Determination

The Commission Panel accepts the allowance for financial flexibility of 50 bps added to the CAPM and DCF tests in determining the fair ROE. As indicated in Section 5.5, the two market-based tests, CAPM and DCF are given equal weight in the determination of the allowed ROE for the benchmark utility.

With reference to Ms. McShane's proposed additional 50 bps if the CE test is not accepted, the Commission Panel is of the view that each test to estimate the fair return is applied separately to provide a different perspective and each test's results are not contingent upon the results of other tests. Therefore, the Commission Panel does not accept the conditional 50 bps in Ms McShane's alternative proposal.

5.7 Fair Return on Equity – Commission Determination

The Panel finds that the DCF and CAPM should be given equal weight in determining the ROE. Moreover, the Panel finds that CE and other ERP models have insufficient merit to be accorded any weight in the determination of the fair ROE. Considering the CAPM based estimate of 7.64 percent and the DCF estimate of 8.9 percent, the Panel concludes that the ROE, before adjustment for financing flexibility, of 8.25 percent is an appropriate base as it falls in the midpoint range of the two estimates. When an allowance for financial flexibility of 0.5 percent is added, the resulting ROE is 8.75 percent, to be effective January 1, 2013, provided for by Order G-47-12 and confirmed in Order G-187-12. **The ROE will be effective until December 31, 2015, subject to variation commencing January 1, 2014, by the Automatic Adjustment Mechanism formula discussed and adopted in Section 6.**

FEI is to file within 30 days of this Decision and accompanying Order G-75-13 amended rate schedules in accordance with paragraphs 1 and 2 of Order G-75-13 as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013. FEI shall inform all affected customers of the final rates by way of customers notice.

6.0 AUTOMATIC ADJUSTMENT MECHANISM

6.1 Introduction

In 1994, the Commission determined that the Benchmark ROE was to be estimated annually by an Automatic Adjustment Mechanism (AAM).⁸ This AAM was eliminated by Order G-158-09 issued concurrently with the 2009 Decision. In eliminating the AAM the Commission stated that: "... in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard." (2009 ROE Decision, p. 72)

One of the stated purposes of this proceeding was to review the possible return to an AAM for setting an ROE of the benchmark utility and examine potential AAM models. In this Section, the Commission determines that:

- Reinstating an AAM formula for annually setting the ROE for a benchmark utility between proceedings is appropriate.
- A two-variable model AAM is to be instituted to set the benchmark ROE on an annual basis commencing in the 2014 calendar year for a period of two years.
- Implementation of the model will be subject to the actual long Canada bond yield meeting or exceeding 3.8 percent.
- The new formula will initially utilize the ROE of 8.75 percent as determined in Section 5.7.

6.2 Should the Commission Re-institute an AAM?

In considering re-instituting an AAM, the Commission Panel reviewed proposed AAMs to determine whether they would meet the Fair Return Standard or whether, as FBCU submit: "The Fair Return Standard is best met in intervening years until the next comprehensive cost of capital reviews by holding the ROE constant." (FBCU Final Submission, p. 153) In addition, the Panel examined the status of AAMs in other Canadian regulatory jurisdictions.

⁸ In the Matter of Return on Common Equity – BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., -- Decision and Order G-35-94, June 10, 1994.

6.2.1 Status of AAMs in Other Canadian Jurisdictions

The Brattle Report surveyed the cost of capital practices in Canada including the formulas used to set the ROEs in Ontario and Quebec. (Exhibit A2-3, pp. 64, 72)

In the 2009 Decision, FBCU was directed to complete a study of AAM alternative formulas and report to the Commission. In compliance, FBCU filed the 2010 report, “A Review of Automatic Adjustment Mechanisms for Cost of Capital” prepared by Concentric Economic Advisers (Concentric). The 2010 Report provided an examination of the use of AAM formulas in other jurisdictions, contrasted these with alternatives and considered the merits of various approaches. While not recommending that a formula be adopted, Concentric identified attributes that should be considered if an AAM is adopted in the future. (Exhibit B1-9-6, Appendix I) In this proceeding, FBCU again engaged Concentric to provide an update of its analysis, which examined the use of ROE formulas in other jurisdictions. The update included the following observations with regard to Canadian jurisdictions:

- The Ontario Energy Board (OEB) continues to rely on its AAM which it modified in 2009. The modified formula is based on 50 percent of the change in forecast long-term Canada bond yields and 50 percent of the change in observed A-rated utility bond index over the 30-year Canada Bond yield.
- In Quebec the Régie de l'énergie (Régie) modified its previous formula in 2012 to incorporate 50 percent of the change in utility bond spreads in addition to the existing formula's 75 percent of change in government bond yields.
- In its December 2011 Decision, the AUC determined that the credit market remained volatile and therefore decided not to employ an AAM for 2012. The AUC indicated that it was not prepared to preclude a return to some form of formula-based AAM in future once the capital markets had stabilized.
- The Newfoundland and Labrador Board of Commissioners of Public Utilities, in June 2012, approved an 8.8 percent ROE (which was not set by formula) for Newfoundland Power stating that this was within a range of reasonable values. The Board did not disavow or abandon the formulaic approach for future rate proceedings.

Concentric has not changed its position on AAMs and stated that: “periodic rate hearings remain the only reliable method for the determination of utility ROE's.” However, Concentric noted that Canadian regulators have recognized that a sole reliance on simple relationships to government bonds cannot be relied upon to estimate ROE. Concentric points out that both Ontario and Quebec have incorporated utility bond spreads in their formulas and notes that this mitigates one fatal

weakness of past AAMs. Concentric views the two variable methodology utilized by Ontario as an improvement with a remaining concern being the lack of a specific link to the cost of equity , other than that conveyed by bond yields. (Exhibit B1-9-6, Appendix I, Concentric Update Report, pp. 1-4, 11)

The Commission Panel notes that both the OEB and the Régie formulas are variations of the model proposed by Dr. Booth and are discussed further in Section 6.2.2 below.

It appears that there is some acceptance by utility regulators in Canada of an AAM formula based on a two-variable model that uses the long-term Canada bond rate as a proxy for a risk free rate and a change in utility bond spreads as a proxy for credit risk. There is, however, reluctance in some jurisdictions to institute an AAM given the volatility of Canadian capital markets in recent years.

6.2.2 Submissions by Parties

AMPC/CEC

AMPC/CEC submit that the Commission abandoned the AAM in 2009 because it did not provide a fair return citing the following passage from the 2009 Decision: “the recent flight to quality has driven down the yield on long-term Canada bond yields, while the cost of risk has been priced upwards.” Therefore, AMPC/CEC submit that the question for the Commission is, “what formula will allow it to return to an AAM, while ensuring that the results are fair in light of the current financial conditions and the conditions FEI might encounter going forward.” (AMPC/CEC Final Submission, p. 62)

AMPC/CEC support a return to an AAM based on its contribution to regulatory efficiency because an AAM reduces the frequency of periodic ROE reviews. They note that FBCU have suggested that 3-5 years is a reasonable gap between comprehensive ROE reviews. AMPC/CEC points out that if the Commission agrees with this, an AAM would likely allow the reviews to be closer to five years rather than three, resulting in considerable efficiency benefits. (AMPC/CEC Final Submission, pp. 62-63)

Dr. Booth states that “The key problem with ‘old’ ROE adjustment models was that they *only* linked the ROE to the forecast long Canada yield. As a result, during the financial crisis the ROE formula

indicated declining ROEs while at the same time the utility cost of debt was increasing. An enhanced ROE formula has to deal with this, which can be done by incorporating the credit market adjustment I have used in my direct ROE estimates.” (Exhibit C6-12, pp. 97, 100)

Dr. Booth recommends “an ROE adjustment model where ROE adjusts by 75% of the forecast change in long Canada bond yields and 50% of the change in the credit spread. This would be subject to a minimum forecast long Canada bond yield of 3.80% ... Similar models are in use by the Régie and OEB.” (Exhibit C6-12, p. 3) Dr. Booth selects 3.80 percent as the “floor” stating that this “is the lowest rate consistent with a normal cyclical low.” (Exhibit C6-12, pp. 97, 100)

AMPC/CEC argue that Dr. Booth’s enhanced two variable ROE formula addresses the concern with the old ROE formula that during periods of financial crisis the allowed ROE and utility borrowing costs move in opposite directions. They argue that Dr. Booth’s formula obviates FBCU’s concern that the AAM won’t work because of the current unusual business cycle. The proposed 3.8 percent floor acts like a fixed rate ROE until the long Canada bond yields return to normal, and it provides an adjustment mechanism for periods when conditions are more typical. (AMPC/CEC Final Submission, p. 64)

ICG

Dr. Safir believes that an AAM for a limited number of years is appropriate because “It is simply not economically efficient to revisit the entire ROE setting mechanism annually” and also states that “the AAM is administratively efficient, resulting in significant savings by avoiding costly, annual rate hearings.” In Dr. Safir’s view, AAMs that reference long-term bond rates, such as the one previously used by the BCUC, are good ways to account for near term influences that affect a fair ROE. (Exhibit C4-9, pp. 36-37)

ICG observes that during the interim years between periodic cost of capital proceedings an AAM formula is more likely to result in an ROE that meets the FRS than no formula. It submits that the Commission should establish an AAM similar to the one discontinued by the Commission in 2009 that referenced long-term bond rates with a three year effective period. It would differ from the previous Commission AAM in that it would use a five year average for the forecast long-term Canada bond yield. (Exhibit C4-9, pp. 36-38; ICG Final Submission, p. 32; T7:1187)

ICG concedes that a multiple factor model may be more likely to meet the FRS than a single factor model, but given that the single factor model has been tested over a long period, it has been recommended to the Commission. (ICG Final Submission, pp. 32-33)

BCPSO

BCPSO submits that an AAM is beneficial because it ensures that the benchmark utility will not operate for more than a brief period of time with a higher than required ROE and therefore supports reinstatement of an AAM. (BCPSO Final Submission, pp. 19-20)

FBCU

FBCU does not support the return to an AAM. FBCU's main concern with the AAM is that the basis upon which the annual ROE adjustments are being made may be suspect. They submit that an AAM relies on a formula with a limited number of inputs that could never capture the complex factors affecting ROE, and that an AAM likely relies on long Canada bond yields and corporate spreads, which are still affected by atypical market conditions. In addition, any formula relies on imperfect proxies. In their view, the application of the FRS requires a significant degree of analysis, market information, and judgment that evolve over time. Formula parameters are static and based on historic relationships and fundamental relationships may shift, leaving the formula out of touch with current market conditions. FBCU take the position that there is no formulaic way to assign a value or weighting to specific risk factors or utility/utility sector characteristics that would apply across multiple utilities and generate the appropriate cost of capital for each one. This is supported by Ms. McShane who submits that the Commission should continue to address the appropriate cost [of capital] on a case-by-case basis: "There is no 'one size fits all' cost that should be determined by means of an interest automatic adjustment mechanism." (FBCU Final Submission, p. 153-156; Exhibit B1-9-6, p. 33; Exhibit B1-9-6, McShane Evidence, Appendix F, p. 7)

FBCU prefer to have the allowed ROE and capital structure set through a traditional process and remain constant between the periodic (three to five year) formal reviews, subject to events occurring that bring the results out of alignment with the FRS, which could result in an unscheduled full review process. This is preferable to having updates made on a basis that the FBCU believe is suspect. (Exhibit B1-20, BCUC 2.113.1)

FBCU argue that there is no efficiency gain associated with implementing the AAM, if there are to be periodic reviews. FBCU further argue that the regulatory burden associated with periodic cost of capital reviews is the same as that associated with periodic reviews with annual formula-driven ROE changes in the interim. FBCU also argue the FRS is best met in the intervening years until the next comprehensive cost of capital reviews by holding the ROE constant. (FBCU Final Submission, pp. 153-156)

FBCU further submit that “The rationale for why the Commission discontinued the AAM remains valid today. Meeting the Fair Return Standard is not optional.” FBCU state that “All of the experts agree that we are still experiencing unusually low interest rates, and the ability of any AAM to produce fair results is far from certain [when such conditions exist].” (FBCU Final Submission, p. 153)

With respect to the positions taken by Dr. Safir and Dr. Booth, FBCU make the following submissions:

1. FBCU submit that Dr. Safir is proposing to return to an AAM that has already been rejected by the Commission, with the only difference being the starting point for measurement of changes in the forecasted long Canada bond yields (i.e., the use of the five-year average forecast). They cite Ms. McShane’s statement that there is an inverse relationship between long-term government bond yields and the utility risk premium. FBCU also argue that Dr. Safir’s use of a five-year average forecast Canada bond yield as the base line in the formula is problematic because it suppresses ROEs despite increases in long Canada bond yields. FBCU submit that while this five year average is intended to compensate for present unusually low interest rates, it would be better to postpone consideration of a formula, rather than implement a “quick fix” that artificially suppresses the ROE. (FBCU Final Submission, pp. 159-160)
2. FBCU submit that the AAM proposed by Dr. Booth is biased downwards. FBCU notes that the current long Canada bond yield is well below the 3.8 percent that Dr. Booth employs as the floor, and points out that while he expects rates to increase, he does not expect the forecast to rise above the 3.8 percent for at least three years. FBCU submit that the combination of rock-bottom forecast yields and a slow rise in interest rates has two implications. First, rock-bottom interest rates means that further declines are not likely. Second, any increase in the forecast long Canada bond rate will not result in an increased ROE. In addition, FBCU submit that the cross-examination of Dr. Booth indicates that he expects credit spreads to fall while the long term Canada bond yield remains below 3.8

percent, an expectation shared by Mr. Coyne. FBCU propose that the result of this will be a progressively lower benchmark ROE after 2013 if Dr. Booth's formula is employed. (FBCU Final Submission, pp. 160-161)

FBCU's position is that if the Commission requires an ROE AAM, it should seek to rectify the problems of the old formula. A new formula would address changes in the equity risk premium, and not solely changes in long Canada bond yields. Any adjustment factor would need to reflect sensitivity to change in bond yields to ROE. (Exhibit B1-9-6, pp. 27-29)

Corix

Corix submits that there is a continued flight to quality and a still increasing cost of risk, so an updated AAM is not appropriate at this time. (Exhibit B2-9, BCUC 1.2.1, p. 3)

6.3 Commission Determinations

6.3.1 Re-instituting an AAM

The Commission Panel does not take issue with FBCU's argument that an AAM formula with limited inputs cannot capture all of the complex factors affecting ROE and therefore, relies on imperfect proxies. However, at the same time, the Panel is of the opinion that the issue is whether the adoption of an AAM formula is better than the alternative, which is to do nothing as suggested by FBCU and Corix. In other words, while implementing an AAM formula may not be perfect, the question is whether it better satisfies the FRS than leaving the ROE static for a period of time or conducting frequent costly and time consuming ROE proceedings. The difficulty with leaving the ROE static over a three year or longer period is that financial markets continue to change and investors' needs continue to evolve. Therefore, in the view of the Commission Panel, implementing a mechanism to capture the impact of some of these changes is far superior to the alternative of doing nothing. Furthermore, as the AMPC/CEC submits, "if there are reasonable grounds to believe the mechanism is not producing fair results, the benchmark utility always has the option of asking for a review." (AMPC/CEC Final Submission, p. 64)

The Commission Panel does not disagree with FBCU's argument that the regulatory burden associated with periodic cost of capital reviews with or without an AAM is similar. However, we are

of the view that the likelihood of a requirement for more frequent ROE proceedings is reduced by having in place an AAM formula. Thus, the Panel is persuaded that the application of the AAM has the potential to contribute to regulatory efficiency.

Therefore, the Commission Panel determines that re-instituting an AAM formula for annually setting the ROE of the benchmark utility between ROE proceedings is appropriate. Additionally, the Commission Panel finds the FRS is adequately met because implementing an AAM formula better meets the standard than taking no consideration of changes in the market over a three year period as suggested by FBCU. The AAM formula to be adopted and the timing of its use is addressed in Section 6.3.2.

6.3.2 Optional AAMs to be Considered

The Commission Panel acknowledges that interest rates have been atypical in recent years and have remained at historical lows. The historical AAM used by the Commission prior to 2009 relied exclusively on a single variable formula based on the long-term Canada bond yields as a proxy for risk free rates. This model was less than fully effective for utilities because the flight to quality kept interest rates abnormally low while the risk had been priced upwards. It could not assure that the FRS could be met in extended times of low interest rates.

As noted previously, Dr. Booth proposed a two-variable model that incorporates the traditional concept of tying the benchmark utility's ROE to the "risk free" long-term Canada bond yield, and also incorporates a credit market adjustment to reflect the relationship of ROE and credit risk within the utility sector. His model also utilizes a "floor" long-term Canada bond rate of 3.8 percent as the risk free proxy until such time as long-term Canada bond yields return to a more common level.

Concentric submits that any new AAM formula should address changes in the utility risk premium and not be based solely on changes to the long Canada bond yields. While it does not recommend a formulaic approach, it does provide several potential formulaic methodologies that could be used in British Columbia (Exhibit B1-9-6, Appendix I, 2010 Report, pp. 39-45)

In summary, possible options for re-instituting an AAM include:

- The single variable model used by the Commission prior to 2009 that was based on long Canada bond yields;
- The variety of approaches offered by Concentric (Exhibit B1-9-6, Appendix I, p. 11);
- Dr. Booth's two-variable model or a variation incorporating the long Canada bond yield, a floor level of long Canada bond yield to address the atypical low interest rates, and a metric to address credit spreads.

The Commission Panel recognizes the shortcoming of the single variable model used by the Commission prior to 2009 in that it fails to satisfy the FRS when interest rates continue at abnormally low levels. Accordingly, this model will not be considered.

While Concentric has explored a number of alternative formulas that could be used in British Columbia, the Commission Panel notes that none of these have been recommended by Concentric nor have they provided evidence as to their use and effectiveness in other jurisdictions. In addition, none of the interveners has expressed support for any of these. Given this lack of support and the lack of evidence to support their efficacy and relevance to British Columbia, the Commission Panel does not endorse any of the possible alternative AAMs explored by Concentric.

During cross-examination, Commission counsel asked Mr. Coyne of Concentric what advice he would give the Commission in terms of adjustments if the Commission were adopt an AAM similar to that of the OEB and the Régie. Mr. Coyne testified that a coefficient of 0.5 was a more accurate reflection of the historic relationship to long-term Canada bonds than 0.75. (T5:827)

Dr. Booth testified that he recommended 75 bps but that he could live with 50 bps and he did not believe that there would be a big impact. (T8:1622)

The Commission Panel is persuaded that a two-variable model similar to that proposed by Dr. Booth and currently utilized in Ontario is appropriate for application to the benchmark utility within British Columbia. (Exhibit C6-15, BCUC 1.44.5 attachment)

By utilizing the 50 percent adjustment of the change in the long-term Canada bond yield as a proxy

for risk free rates, it recognizes the relationship between ROE and risk while moderating the level of change resulting from any volatility in the long-term Canada bond rate. In addition, by utilizing the 50 percent adjustment in the change in the utility bond spreads, it recognizes the relationship between credit risk and ROE in the utility sector and moderates volatility in utility bond spreads. And finally, by utilizing a 3.8 percent floor for the long Canada bond yield, it recognizes the atypical relationship between ROE and cost of risk in periods of unusually low interest rates. Further, the application of similar models within both Ontario and Quebec supports its usefulness and acceptance within other Canadian regulatory jurisdictions.

Given the advantages, the Commission Panel adopts a two variable model AAM to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. The AAM formula will operate until December 31, 2015. The implementation of the model is subject to conditions outlined in Section 6.3.3. The formula will initially utilize the 8.75 percent ROE as determined in Section 5.7 as the base ROE.

The formula to be used and the basic method to determine the changes in long Canada bond forecast and the changes in utility bond spread are provided as follows:

$$ROE_t = \text{Base ROE (8.75\%)} + 0.50 \times (LCBF_t - \text{BaseLCBF}) + 0.50 \times (\text{UtilBondSpread}_t - \text{BaseUtilBondSpread})$$

Where:

LCBF_t is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent. The Base LCBF is 3.8%.

UtilBondSpread_t is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields and BaseUtilBondSpread will be determined.

6.3.3 Impact of a 3.8 percent Floor

FBCU has argued that the AAM proposed by Dr. Booth is biased downwards. The Commission Panel agrees that the potential for a downward bias does exist.

Dr. Booth has recommended that any change in the ROE be subject to a minimum forecast bond

yield of 3.8 percent as this is the lowest rate which is consistent with a normal cyclical low. The Commission Panel accepts this as reasonable since it is the risk free rate for the CAPM ROE as determined in Section 5.2.

With respect to the two-variable AAM formula, Dr. Booth has acknowledged that as long as the long-term Canada bond yields are below 3.8 percent, the only variable that can affect ROE is the corporate utility bond spreads. FBCU submit that if the credit spread drops or tightens before long Canada bond rates are above 3.8 percent, the ROE will drop further from whatever the starting point is under his formula. Further, Concentric states that “a troubling aspect of Dr. Booth’s proposed formula is that it sets a minimum floor LTC yield of 3.8 %, which will be applied for purposes of measuring year over year changes in the formula, but does not specify an objective bond forecast to reference for the starting point.” (Exhibit B1-32, Concentric Rebuttal Evidence, Concentric Response to Interveners, p.4) The Panel notes that all parties seem to agree that long-term Canada bond yields are well below what would be considered a cyclical low and have been influenced by monetary policy. Therefore, it is reasonable to assume that the likelihood of an increase in the yields of long Canada bond is much more likely than a decrease. If this were to occur with no corresponding change in utility bond rates, the result would be a decrease in the credit spread and, consequentially, the ROE. Given that a rise in the long Canada bonds yields may be driven by monetary policy and not a change in market conditions, and there is no evidence to suggest there would be a corresponding change in utility bond rates, the Commission Panel accepts that a potential for downward bias exists. **To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded. Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent.**

The Commission Panel has considered Concentric’s submission that Dr. Booth did not specify an objective bond forecast to reference as a starting point. We are of the view that the potential for downward bias will continue if attention is not paid to setting appropriate base rates for the formula. Therefore, the Commission will seek submissions from the parties with respect to determining appropriate base levels and developing an effective methodology for deriving the inputs to the formula.

The Commission Panel understands that the conditions placed upon the implementation of the AAM

formula may well result in the 8.75 percent ROE being in place for the term of this Decision ending December 31, 2015. However, in consideration of the FRS, the Panel is of the view that this is appropriate.

FEI is directed to file an application for the review of the common equity component and the ROE approved in Order G-75-13 by no later than November 30, 2015.

7.0 COST OF CAPITAL – SMALL UTILITIES

7.1 Introduction

When the Commission initiated the GCOC Proceeding, it identified the Affected Utilities, which included FEI and other FortisBC gas and electric utilities, PNG and Corix. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. In addition, the Commission identified Other Utilities that “may wish to participate in the GCOC Proceeding.” This list included among others:

- Big White Gas Utility Ltd. and Sun Peaks Utilities Co. Ltd.;
- Central Heat Distribution Ltd.;
- Dockside Green Energy LLP;
- Hemlock Valley Electrical Services Limited; and
- River District Energy Limited (River District).

The recent emergence of thermal energy services (TES) in British Columbia has resulted in the creation, over the last few years, of a number of new on-site thermal energy systems and district energy systems, which are subject to the Commission oversight. For instance, FortisBC Alternative Energy Service Inc. (FAES), an affiliate of FEI and a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), now owns and operates or is proposing to develop the following regulated TES projects:

- Delta School District Number 37;
- Tsawwassen Springs Development;
- PCI Marine Gateway;
- TELUS Garden Thermal Energy System; and
- Kelowna District Energy System.

Key purposes identified by the Commission Panel in its Final Scoping Document were to establish:

- (i) a method to determine the appropriate cost of capital for a benchmark low-risk utility in BC and how the Benchmark ROE will be reviewed and/or adjusted;

- (ii) a generic methodology or process for determining each Affected Utility's cost of capital in relation to the benchmark utility's cost of capital; and
- (iii) a framework for determining the appropriate cost of capital for other smaller utilities in the province.

Related to this framework, the scope of the proceeding included the following key activities:

- (i) establish a generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility;
- (ii) in certain circumstances, develop a methodology to establish a deemed capital structure and deemed cost of debt, particularly for those small utilities without third-party debt, which would involve setting a methodology on how to calculate a deemed interest rate.

(Exhibit A-3, Appendix B to Order G-47-12)

The Commission Panel also requested submissions regarding Stage 1 and Stage 2 review. The FBCU submitted it would be most efficient to break the process down into three groups which would be handled separately: one for the FBCU, a second for the PNG and a third for micro utilities including Corix and FAES and others. (Exhibit B1-22, pp. 10-11) By Order G-148-12, the Commission Panel directed that a Stage 2 will be added to this GCOC proceeding with the schedule to be determined prior to the end of Stage 1. (Exhibit A-21)

Transition to Stage 2

The purpose of the Stage 2 proceeding is to assess the differences in short and long-term risk faced by the Affected and Other Utilities as compared to the benchmark utility FEI. Based on this assessment the Panel will then determine how the risk differentials will impact the capital structures and the allowed ROE for these utilities.

The Panel acknowledges the FBCU submission that it may be efficient, given the small size of thermal energy systems, to have a single process to address cost of capital issues for TES systems, irrespective of the provider. This would include FEI and FAES's Thermal Energy Services, and similar systems to be operated by developers or providers like Corix. (Exhibit B1-9, p. 34) The Panel also notes the previously mentioned FBCU suggestion about dividing the Stage 2 process into three groups.

In anticipation of Stage 2, this section addresses issues related to the framework for determining the cost of capital for the smaller utilities, including all new small TES utilities. The appropriate method to determine interest rates for deemed debt will also be addressed. In this Decision, the definitions of “small utilities” and “micro utilities” are used interchangeably.

7.2 Framework for Establishing an Appropriate Cost of Capital – Equity Risk Premium

7.2.1 Is Size a Risk Factor in ROE and Capital Structure Determination?

Ms. Ahern, the expert witness for Corix states “it is conventional wisdom, supported by actual returns over time, that smaller companies tend to be more risky, causing investors to expect greater returns as compensation for that risk.” Ms. Ahern further explains that smaller companies, for instance, face more risk exposure to business cycles and economic conditions, both nationally and locally. Similarly, the loss of revenues from a few larger customers would have a greater effect on a small company than on a much larger company with a larger, more diverse customer base. Moreover, smaller companies are generally less diverse in their operations as well as experiencing less financial flexibility. (Exhibit B2-7, pp. 6-7)

Ms. McShane, the expert witness for FBCU states that in the assessment of investment risk, size has two dimensions that should be considered in determining a utilities common equity ratio and ROE:

1. A small utility does not have the opportunities to diversify its risks to the same extent as a larger utility. For example, assets are typically more concentrated in a limited geographic area, which limits operational flexibility.
2. Smaller utilities have fewer financing options, less institutional interest in acquiring their debt securities, issued debt would be relatively illiquid, and, if issued to third-parties would likely require stricter covenants than debt issued by large utilities.

Ms. McShane also points out that debt rating agencies often take size into account when rating companies and their debt issues. The impact of smaller size for rated utilities is frequently exhibited in lower debt ratings for these companies even in cases where their financial parameters are stronger than their larger peers. (Exhibit B1-9, Appendix F, p. 134)

PNG submits “there was little to no evidence submitted that suggested or countered that size was not a significant factor.” While precedents and empirical studies exhibit a broad range of explicit company size adjustments (150-436 bps), which introduces a degree of subjectivity, PNG further submits that “Stage 1 evidence concerning size as an independent factor was relatively uncontested.” (PNG Final Submission, p. 13)

7.2.2 Stand-Alone Principle

Both Ms. Ahern and Ms. McShane reaffirm the importance of the stand-alone principle, which is “a cornerstone of Canadian utility regulation with a history dating to at least 1978.” (Exhibit B1-9, Appendix F, p. 10, B2-9, BCUC 1.4.7) Therefore, even if a small utility is owned by a larger parent company, there should be no impact on the determination of the small size utility ROE and capital structure. Each utility within the Commission’s jurisdiction should be evaluated on a stand-alone basis.

Ms. Ahern further states there is ample academic evidence that investors demand greater returns to compensate for the lack of marketability and liquidity of the securities of smaller firms. She submits “it is the use of funds invested and not the source of those funds which gives rise to the risk of any investment.” She refers to the text of Brealey and Myers, which notes “Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put.” (Exhibit B2-7, p. 7)

7.2.3 Academic Evidence of the Size Effect in Literature

In her filed evidence, Ms. Ahern provides additional examples of the academic literature, where the risk effects of a company’s size on the investor required return is addressed:

Eugene F. Brigham, *Fundamentals of Financial Management*:

A number of researchers have observed that portfolios of small-firms have earned consistently higher average returns than those of large-firms stocks; this is called “small-firm effect.” On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; what the small-

firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of large firms.

(Exhibit B2-7, PMA-3, p. 4)

Giacchino and Lesser, *Principles of Utility Corporate Finance*:

In general, smaller firms face greater financial risk than do large firms... Generally, firm size is measured in terms of total capitalization (i.e., the market value of a firm's equity). Empirical studies have typically found that small firms typically have higher returns over the long run than larger firms. (Exhibit B2-7, PMA-4, p. 3)

Fama and French, in "*The Capital Asset Pricing Model: Theory and Evidence*," *Journal of Economic Perspectives*, note that size is a risk factor which must be reflected when estimating the ROE:

...the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market returns and are priced separately from market betas. (Exhibit B2-7, PMA-5, p. 14)

Based upon this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect of size on the rate of return on common equity.

Marc Reinganum, "*A Possible Explanation of the Small Firm Effect*," *The Journal of Finance*:

While the OLS estimates seem to understate the betas of small firms, the excess returns not explained by the misestimation could easily exceed twenty percent per year on average. Thus, one can conclude with confidence that the small firm effect is still a significant economic and empirical anomaly. (Exhibit B2-6, PMA-6, p. 9)

From her academic research, Ms. Ahern concludes that:

- The specific, unique risks of the investment (e.g. utility) must be reflected in the rate of return; and
- The size of an investment (e.g. size of the utility) is one of those unique risk factors for which investors must be compensated. (Exhibit B2-7, pp. 10-11)

7.2.4 Empirical Evidence for the Risk Effects of a Company's Size on the Investor's Required Rate of Return

Studies on small size and returns have quantified the impact of a firm's small size on the required return based on an analysis of the relationship between betas and historical returns for companies of different sizes. Ms. McShane and Ms. Ahern state the analyses indicate that small companies tend to exhibit higher betas than larger companies. Two empirical studies reviewed by Ms. Ahern are:

Morningstar/Ibbotson Size Premium Study (Firm Size and Return)

Ibbotson SBBI – 2012 Valuation Yearbook

This study constructs decile (10) portfolios of the companies contained in the NYSE, AMEX and NASDAQ. Ms. Ahern suggests that the study can be used to determine the approximate risk premium due to size for a specific utility over the benchmark utility return. This is done by comparing the size premium appropriate for the decile in which the benchmark utility would fall based on the estimated market capitalization with the size premium appropriate for the decile in which the specific utility would fall based on market capitalization.

	Decile	Market Capitalization (\$Millions)	Size Premium (%)
Benchmark Utility	5	2,246 (average)	1.74
Micro-Cap	10	92	6.10
Size Premium			4.36%

(Exhibit B2-6, PMA-8, Table 7-1 and 7-5)

Duff & Phelps Size Study and Risk Study

The Size Study analyzes the relationship between equity returns and company size in a similar manner as the Morningstar Study. It could also be used to determine the magnitude of any necessary risk premium due to the size of a specific utility relative to the benchmark. In addition to presenting risk premia and size premia for 25 size-ranked portfolios using the traditional market

capitalization measure, this study also considers seven other measures of company size, including book value of equity, 5-year average net income, market value of invested capital, total assets, 5-year average EBITDA, sales and number of employees. (Exhibit B2-7, PMA-9, p. 30)

The Risk Study is an extension of the Size Study. The main difference is that while the Size Study analyzes the relationship between size and return, the Risk Study analyzes the relationship between fundamental risk measures (based on accounting data) and return. These are called “fundamental” measures of a company risk to distinguish these risk measures from a stock market-based measure of equity risk such as betas. (Exhibit B2-7, PMA-9, p. 65)

Corix provided a calculation of the size risk premium for micro utilities over the benchmark based on the Duff & Phelps Study. This resulted in a 3.89 percent risk premium as opposed to the 4.36 percent size premium based on the Morningstar Study. (Exhibit B2-8, Attachment to BCPSO 1.1)

7.2.5 Regulatory Support for Size Premium

Ms. Ahern provided only one example of a jurisdiction which has adopted the size premium concept. She cites the Florida Public Service Commission (FL PUC), which adds for small water utilities a bond yield differential, a 50 bps private placement premium and a 50 bps small utility risk premium to the ROE based upon the index of natural gas utilities. Regardless, Ms. Ahern recommends that the size risk of each utility be measured in accordance with the Morningstar/Ibbotson and the Duff & Phelps studies. Specifically, Ms. Ahern states “all of these risk premium spreads should then be averaged and through the exercise of informed expert judgement, a determination of the appropriate risk premium to be added to the benchmark utility return on equity to reflect the size risk of the utility/project relative to the benchmark utility.” (Exhibit B2-9, BCUC 1.12.1; Exhibit B2-8, BCPSO 1.2.1)

In responses to IRs and during cross-examination, Ms. Ahern made it clear that she is not recommending any particular amount of a size premium to be adopted by the BCUC but is simply providing testimony for the purpose of establishing a framework. (T6:1128) Similarly, Ms. Ahern states the 4.36 percent risk premium shown in the example would only represent the upper limit of a size premium above the allowed benchmark ROE due to small size. Where in the 10th decile, Corix or any of its projects fall needs to be evaluated to determine the exact risk premium it would

propose. Corix stated it has not yet undertaken a comprehensive study of the appropriate size risk premium above the benchmark for each of its projects and indicated that such a study will be conducted in the next phase of the GCOC proceeding. (Exhibit B2-9, BCUC 1.13.2)

Ms. Ahern acknowledged that based on her experience the regulatory support for a specific size premium has been minimal and that ultimately any risk premium, whether it is linked to business risk in general or size specifically, is a matter of informed expert judgment. (T7:1278-1284) Further, Ms. Ahern could provide only seven cases out of over 200 regulatory proceedings where she has been involved that resulted in an allowed size adjustment. Yet, in a response to an undertaking, it appears that only two of those seven cases *specifically* reference “size” in the determination of the overall ROE and only one case granted a specific size premium. (Exhibit B2-14) Furthermore, the Panel notes that Ms. Ahern had recommended only modest size adjustments in the range of 25-50 bps in all those seven cases.

Ms. McShane concludes the empirical study findings indicate that small size is a factor that both debt and equity investors are concerned with, and which should be taken into account when evaluating ROEs and capital structures of individual utilities in British Columbia. (Exhibit B1-9, Appendix F, p. 136)

Commission Determination

Stand-Alone Principle

The Panel reaffirms the long history and importance of the stand-alone principle in Canadian utility regulation. The determinations on the benchmark ROE and capital structure in this Decision are based on this principle. Therefore, there is no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility. These projects can represent either a “new” utility with a greenfield operation and no historical performance data or an existing facility being developed into a TES project. Each project needs to be considered individually and independently.

The Size Premium

The Panel has considered the evidence on record regarding the academic literature on the size effect as well as the empirical evidence for the risk effects of a company's size on the required rate of return. Noteworthy is the lack of regulatory support for the recognition of a small size risk premium. Finally, the Panel notes the requirement for on-going exercise of informed judgment by both the Commission and experts retained by the utilities, which was acknowledged by Ms. Ahern.

As a result, the Panel recognizes the academic literature and empirical studies seem to support the importance of size in explaining returns. At the same time, however, the evidence presented does not indicate how adjustment for size should be implemented.

Accordingly, the Panel determines that the small size factor should be further considered in the Stage 2 proceeding, but only as one of the many business and financial risks small utilities or projects are exposed to. Utilities are encouraged to use other methodologies or approaches to justify their risk differential in relation to the benchmark. The Panel has not been sufficiently persuaded to put any weight to the empirical studies reviewed to date.

The Panel notes that the Commission developed a risk matrix that has been used in various small TES utilities proceedings to evaluate overall risk of a given project. The "size" factor is one of the risk factors included in the matrix. **The Panel recommends that the small utilities use this risk matrix attached as Appendix B to Order C-1-13 of the TELUS Garden Decision⁹ in the Stage 2 proceeding and for future projects to justify their case for the appropriate capital structure and risk premium over and above the benchmark ROE.** For convenience, the risk matrix is attached in Appendix E of this decision. Small utilities, other than TES, can modify this matrix to facilitate a similar comparison of their own short and long-term risks to those of FEI.

The Panel is cognizant of the on-going Phase 2 of the Alternative Energy Solutions (AES) Inquiry,¹⁰ which involves development of a regulatory framework for dealing with small TES utilities. This evolving process will further influence the nature and content of future TES applications.

⁹ Certificate of Public Convenience and Necessity Order C-1-13 and Reasons for Decision dated February 5, 2013, regarding FAES Telus Garden Thermal Energy Services

¹⁰ In the Matter of FortisBC Energy Inc. Inquiry into the Offering of Products and Services in Alternative Solutions and Other New Initiatives

7.3 Guiding Principles for Setting Deemed Capital Structure and Deemed Debt

7.3.1 Determination of Deemed Capital Structure

The Commission deems an appropriate common equity ratio for the utility. The resultant debt ratio is simply the residual between 100 percent and the deemed equity ratio. However, the deemed component typically incorporates actual debt issues where rates can be objectively observed and determined. In some cases, the utility manages its actual financing to mirror the deemed debt/equity ratio.

Ms. McShane explains the actual debt issues may consist of issues that have been made directly into public markets; they may be private placement to third party institutions such as bank or insurance companies, or they may be non-arms length issues between a utility and affiliated company. In the latter case, there is a contract between the utility issuer (a legal entity) and the affiliated company, which specifies the terms and conditions of the loan, with rates that are based on market conditions. When the parent company issues debt, the subsidiary can enter into an arrangement with the parent for a specific portion of that debt issue, with the same terms as the third-party issue. Alternatively, the utility may enter into an arrangement with its parent for a debt issue that reflects the utility issuer's risk profile, funding requirements and market conditions at the time the issue is made, but is not tied to a specific third-party issue made by the parent. (Exhibit B-1-9-6, McShane Evidence, Appendix F, p. 121)

7.3.2 Criteria for Setting the Deemed Capital Structure

Ms. Ahern, the Corix expert, states that an appropriate deemed capital structure should:

- be reasonable relative to or consistent with the average capital structure of the particular utility industry;
- reflect the specific utility's unique risks, including its relative size;
- be consistent with bond rating agency metrics; and
- provide the opportunity for the utility to earn a reasonable and fair rate of return, given its unique risks, e.g., size etc.

(Exhibit B2-7, p. 19)

Ms. McShane provides general principles that should be observed when setting the ROE and common equity ratio for utilities, regardless of size:

- The combination of ROE and common equity ratio awarded to each utility in relation to the overall return adopted for the benchmark utility should reflect the level of that utility's business risk relative to that of the benchmark utility;
- The overall return awarded to each utility should be comparable, on a risk adjusted basis, to the overall return awarded to the benchmark utility;
- The capital structure, in conjunction with the ROE, should be adequate to permit the utility, on a stand-alone basis, to achieve investment grade debt ratings, with the caveat that some utilities may not actually have a credit rating; and
- There is a trade-off between equity ratio and ROE. For example, if a utility is not fully compensated for higher business risk than that of the benchmark utility through its common equity ratio, its ROE needs to be higher than the ROE granted to the benchmark utility. (Exhibit B1-9-6, p. 129)

7.3.3 When Is Deemed Debt Appropriate?

The FBCU state the deemed debt is appropriate for small utilities in cases where raising debt is inefficient. For example, a separate division or class of service within a larger regulated utility can contain a stand-alone project. Similarly, a regulated utility subsidiary/affiliate within a larger corporate organization can face circumstances where either:

- (i) The high cost of debt issuance relative to the size of the issue makes the effective debt cost higher than it would be otherwise; or
- (ii) The size of the utility precludes it from accessing appropriate debt terms.

The FBCU further state that the assessment as to whether deemed debt is appropriate and efficient should involve some judgment to ensure that the use of deemed debt is limited to circumstances where it is efficient to do so. Finally, FBCU state "it is reasonably clear that deemed debt would be appropriate for FEW (a separate legal entity), the Fort Nelson Division of FEI, and FAES." (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.1, 1.140.2)

7.3.4 Setting the Appropriate Deemed Debt Rate and Term

The FBCU state that deemed debt rates and duration should reflect the particular circumstances of each utility. Utilities for which a deemed cost of debt might be appropriate may have differing profiles; FEW, for instance, is not the same as one of FAES's TES projects or Corix's UniverCity project. The appropriate term of debt may also vary even among projects with a broadly similar risk profile. (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.2)

Ms. McShane submits as a general proposition that the term should reflect the long-term nature of the assets and offers the following additional considerations:

1. If the specific utility operations are backed by contractual arrangements, the length of the contract would be a relevant consideration in the determination of the term for the debt.
2. The higher the risk of the specific operation, the less their ability would be to obtain "real" debt on a long-term basis; i.e., on terms longer than 10 years. The term of the debt should reasonably reflect the limitations of what would reasonably be available to operations with a similar risk profile.
3. The appropriate term for the deemed debt also depends on the state of the capital markets.

Ms. McShane concludes that the individual utilities' circumstances may differ in terms of risk, the funding requirements and appropriate terms of debt. Accordingly, she recommends that the Commission continue to address the cost of deemed debt for each utility separately, on a case-by-case basis. In her view, there is no "one size fits all" cost mechanism. (Exhibit B1-9-6, pp. 123-124)

Commission Determination

Before addressing the issue of short-term and long-term debt in the deemed capital structure and the methodology for determining a deemed interest rate, the Commission Panel wishes to reaffirm certain principles for the Stage 2 GCOC proceeding framework.

- (i) The general principles and criteria outlined by the Corix and FBCU experts for setting the capital structure for any utility in general and the deemed capital structure specifically for the small utilities are accepted as they are consistent with the principles adopted for setting the benchmark ROE;

- (ii) Deemed debt is appropriate for small utilities in cases where raising debt is inefficient;
- (iii) Deemed debt rates and duration should reflect the particular circumstances of each utility. Accordingly, the Commission should continue to address the cost of deemed debt for each utility separately on a case-by-case basis; and
- (iv) Risk assessment of small utilities, especially the TES projects, must include consideration of rate setting mechanisms, deferral account treatment, length of term and the overall risk/reward equation.

Related to the issue of deemed capital structure and deemed debt are two key questions that the Stage 2 GCOC proceeding must address more comprehensively:

1. Can the combination of the deemed debt/equity ratio and the allowed ROE sufficiently compensate for the unique risks of a particular small utility or project?
2. How important is it to maintain consistency between the risk premium determination and assigning a deemed credit rating for a small utility without third party debt? For instance, would it be reasonable to allow no risk premium over FEI for a TES project while setting the debt rate based on a BBB bond rating?

7.4 Appropriate Portions of Short-Term and Long-Term Debt in the Deemed Capital Structure

In British Columbia, in some of the more recent TES Decisions, the Commission has considered deeming a portion of overall debt to short-term debt. To date no determination has been made to put this into effect. However, the Panel notes that the OEB has officially deemed a standard four percent proportion of short-term debt component for utilities under its jurisdiction for reasons that it outlined in its 2006 Decision:

- (i) All utilities actually use some short-term debt;
- (ii) Short-term debt is generally less expensive than long-term debt and provides greater financing flexibility; and
- (iii) While actual short-term debt percentages may seem to be a more accurate approach, it is administratively challenging given the number of distributors regulated by the OEB.¹¹

¹¹ OEB, Report of the Board on Cost of Capital and 2nd Generation incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, pp. 9-10

In 2009, the OEB reaffirmed this practice for natural gas distributors as well. It also updated its methodology to estimate the deemed short-term debt rate. (Exhibit A2-21, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, EB-2009-0084)

Ms. McShane states there is no single right answer to the question of what proportion of a deemed capital structure should be designated as short-term debt. She notes that annual fluctuations for individual utilities will reflect, among other things, the fact that utilities frequently use short-term debt as a bridge between long-term debt issues. Based on her filed evidence she further states that the average proportion of short-term debt to total capital for rated Canadian utilities has been approximately 1 percent to 2 percent. Her review of 2010 data for Ontario electricity distributors indicated that the average and median actual short-term debt ratios were at 2.9 percent and 0.4 percent respectively. (Exhibit B1-9-6, pp. 125-127)

Ms. Ahern states that conceptually the maturity of the debt capital should match the life of the assets being financed. But when the inclusion of short-term debt is optional, its inclusion should be based upon several criteria:

- If its use is sporadic and hence, volatile, it should not be included in the capital structure. However, if its use is consistent and especially at a significantly high level, it is likely financing rate base and possibly should be included;
- If its use is seasonal and self-liquidating, e.g., financing short-term inventories of natural gas in anticipation of heating season, it probably should not be included;
- If short-term debt is financing working capital, it should be included;
- If it is used as bridge financing until permanent financing can be put in place it should be included at the expected cost rates of that permanent financing; and
- If the short-term debt financing construction projects and if the Construction Work In Progress (CWIP) are included in rate base the short-term debt should be included. (Exhibit B2-7, pp. 23-24)

The FBCU provided information showing actual percentages of short-debt for FEI, FEI – Fort Nelson, FEVI, FEW, and FortisBC Inc. for the 2002-2012 period. While there has been significant fluctuation over the years, the average percentages for the period as a share of capital structure amounted to

5.28 percent, 8.58 percent, 10.77 percent, 13.10 percent and 5.27 percent for each respective utility. (Exhibit B1-24, BCUC 2.189.1, 2.189.2)

Commission Determination

The Commission Panel finds it as an accepted fact that all utilities use some short-term debt financing. The FBCU IR responses clearly support this. While there are varying reasons for its use, the evidence demonstrates that, on average, utilities always carry a small portion of short-term debt in their capital structure. The construction work in progress, due to its nature, is often financed by short-term debt.

Accordingly, the Commission Panel finds it reasonable and prudent to include a deemed component of short-term debt in the capital structure for all small utilities without third-party debt to reflect reality. To establish the percentage of short-term debt to be deemed, the Panel has considered testimony of Ms. McShane, FBCU IR responses and the OEB established practice in Ontario. **While acknowledging that there is no correct amount, the Panel concludes that a four percent component for deemed short-term debt provides a reasonable proxy as it is the midpoint of the range of actual short-term borrowing.**

7.5 Setting the Deemed Interest Rates

7.5.1 Deemed Interest Rate for Long-Term Debt

Parties acknowledge that there are at least three reasonable options for determining the deemed interest rate applicable to a small utility without third-party debt. These options are summarized below.

FBCU Option 1:

Step 1: Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity. The FBCU submit this approach is consistent with the stand-alone principle, and is how FEW has financed the debt component of its capital structure. (Exhibit B1-9, pp. 29-30; Exhibit

B1-20, BCUC 1.141.1, 1.141.5, 1.144.2) A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB (low), with the deemed debt cost set on this basis. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 123; Exhibit B1-20, BCUC 1.147.1)

Step 2: Determine a Government of Canada (GoC) bond yield reflecting the proposed term of debt that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of the two. The selected benchmark should reflect the long-term nature of utility assets, contractual terms and available debt terms. (Exhibit B1-9, p. 30)

Step 3: Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond. (Exhibit B1-9, p. 30; Exhibit B1-24, BCUC 1.141.5.2; Exhibit B1-24, BCUC 2.188.2, 2188.3)

FBCU Option 2:

Ms. McShane identified an alternative approach to use the embedded cost of debt of the issuing entity as the deemed interest rate and allocate the deemed debt and interest rate based on an approved capital structure. Currently, FEI-Fort Nelson debt is deemed and the rate is the embedded cost of debt. (Exhibit B1-20, BCUC 1.141.1, 1.141.6) The FBCU submit that this is an administratively efficient way to allocate debt issued by a single regulated entity, allows the benefits of issuing all debt centrally to be shared, and provides a reasonable degree of assurance that the regulated entity raising the debt will be able to recover its actual incurred cost of debt. (Exhibit B1-20, BCUC 1.148.8)

Corix Option:

Corix supports FBCU's recommendation to apply one benchmark credit spread for small utilities to provide regulatory efficiency. To align with the proposed method, the benchmark credit spread would reflect the spread for BBB and BBB (low) rated debt relative to the underlying 10 year GoC bond yield and would reflect incremental risk of small utilities. Corix states that with the benchmark set for small projects, project stakeholders and interveners can then justify any variances from the benchmark depending on the risk exposure. (Exhibit B2-9, BCUC 1.26.3, 1.27.1, 1.46.5, 1.46.7, 1.46.11)

Commission Staff Option:

This option was raised in order to account for the scarcity of BBB-rated utilities in Canada that can be used as proxy, and for the possibility that utility ratings can be changed.

Step 1: Obtain the yield on an appropriate GoC bond as the benchmark.

Step 2: Assign a credit rating to the stand-alone utility/project based on an assessment of financial and business risk (e.g., BBB, other)

Step 3: Obtain the bond yield (credit) spread between GoC bond and a high grade utility (A or A low) and add it to the rate in Step 1.

Step 4 Add a premium, if required, to the credit spread in Step 3. This premium will be calculated as the credit spread between high grade utility bonds (A or A low) and utility bonds of the credit rating estimated in Step 2. The use of historical data (e.g., two most recent years) to have more data points could be considered. (Exhibit A2-43; Exhibit B1-20, BCUC 1.141.9; Exhibit B1-24, 2.188.6; Exhibit B2-9, BCUC 1.26.6)

The FBCU submits it is generally supportive of the Staff option but raised one concern. Ms. McShane cautioned that for any method involving the use of credit rating proxy companies, care should be taken to employ reasonable credit ratings. She re-emphasized that an appropriate credit for small utilities would be BBB to BBB (low), as the inherent risk of small size would preclude them from achieving higher ratings:. “As it is much more likely that the small utility would be BBB on a standalone basis, it makes sense to use a BBB yield as the benchmark to begin with rather than using A-rated proxies.” (FBCU Final Submission, pp. 164-165; T5: 680-681)

Commission Determination

The evidence and Final Submissions suggest that setting the deemed interest rate is not a very controversial issue. However, each option reviewed has advantages and disadvantages. The Panel also notes that similar approaches have been adopted in number of recent TES Decisions. For example, BBB-rated proxies were used for the Delta School District Number 37 and Tsawwassen Springs projects.

The Commission Panel has already found that the cost of deemed long-term debt (rate and term) for each utility should be addressed separately on a case-by-case basis. Based on this the Panel recommends that on a go-forward basis the FBCU's Option 1 be used as a guideline for setting the deemed debt rate. The Panel is cognizant of the refinement proposed by Commission Staff to account for the scarcity of BBB-rated utilities in Canada that can be used as a proxy. Should this become a major issue in the future, the Commission can consider switching to use the Commission Staff Option as the guideline.

Because the deemed long-term debt by definition is set for a fixed term, the Panel finds that adjustments will not be necessary during the term of the loan. The only reason for a re-opener would be the situation where a small utility actually issues new debt. The impact of the rate change could be considered a subsequent revenue requirement review.

However, to allow some flexibility, the utilities will have an option to apply for a rate adjustment in accordance with the following reopener-criteria:

- **A measurable change in market conditions**
- **A measurable change in actual debt costs**

The Commission will consider each application for a rate adjustment on a case-by-case basis.

7.5.2 Deemed Interest Rate for Short-Term Debt

The FBCU state the basis for determining the deemed interest rate for short-term debt would be similar to that of long-term interest rate determination. It would be based on indicative credit spread quotes from investment dealers or banks using comparable proxy issuers plus a short-term benchmark yield. A common benchmark yield in Canada is the Canadian Dealer Offered Rate (CDOR). CDOR is the quoted benchmark that is used when a company issues short-term Bankers' Acceptances (BAs), which reflect the short-term benchmark rate plus the company's applicable credit spread. (Exhibit B1-9, p. 31) In response to IRs, the FBCU clarified that quotes from banks would be obtained based on indicated credit rating, not by individual proxy issuer. (Exhibit B-20, BCUC 1.44.2, 1.44.3)

Ms. McShane states that three-month BAs are also a common benchmark for establishing the cost of short-term debt for utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 127-128) In response to IRs the FBCU confirm that either the 3-month CDOR or 3-month BA rate is reasonable for setting the short-term rate. Regarding the indicative credit spread quotes, the FBCU state the following approach used by the OEB is reasonable: the OEB obtains up to six quotes from banks. If it obtains six quotes, it discards the highest and the lowest and uses the average of the remaining four. If less than four are obtained, it uses the average of all the quotes obtained. (Exhibit B1-20, BCUC 1.144.4) The FBCU submit that the OEB formulaic approach is an efficient and transparent way of estimating a deemed short-term debt rate. However, the FBCU stress that the OEB methodology is premised on a single debt rating, a short-term debt rating of R1-low, which generally corresponds to long-term credit ratings in the A category; i.e., higher than would be applicable to the small utilities. To overcome this problem, the FBCU suggest using a more reasonable short-term credit rating, one that would correspond to a BBB/BBB (low) on the long-term rating scale. (Exhibit B1-20, BCUC 1.144.5, 1.144.5.1)

Commission Determination

The Commission Panel recommends that small utilities use either the 3-month CDOR or 3-month BA rate as a basis and obtain 3-4 quotes to establish the credit spread for the purpose of setting the deemed short-term interest rate. Because it is highly unlikely that small utilities, especially the TES utilities/projects, will have frequent revenue requirement reviews, the Panel finds that there is no requirement for an annual adjustment mechanism. **The short-term rates are to be reset at the time of the revenue requirement review only.**

8.0 OTHER MATTERS

8.1 Reliance on Less Complex Financial Methodology

Expert witnesses in this proceeding expressed reluctance to use more complex models that could improve understanding and/or estimating the cost of equity. For instance, Ms. McShane states: “I think it’s reasonable to try to capture these other factors. I know that it’s been difficult to have regulators accept the Fama/French type models ...” (T5:721)

In response to a question from Commissioner Giammarino, Dr. Vander Weide expressed similar concerns:

COMMISSIONER GIAMMARINO: “And [Fama/French] suggest that maybe the future is in an inter-tempo CAPM, that has multi factors. And that would allow for changes in the opportunities – the investments that are available to investors. Did you consider that as an alternative?” (T6:1103)

DR. VANDER WEIDE: “That would certainly be an alternative, but from my years in testifying on the cost of capital, I have realized that there are two qualities that make a model present reasonable evidence. One is that it’s -- you can estimate the inputs to the model reasonably well, and two, it has to be reasonably easy to understand. So that one can judge the model in the context where everyone doesn’t have Ph.D.s in finance or economics. And once you get into dynamic capital asset pricing models, to me that’s getting into a level that’s too complicated for discussion in a public forum.” (T6:1103)

Although Dr. Booth added a credit spread adjustment to his CAPM analysis, he also expressed a similar sentiment about adding further factors to his CAPM, as shown by the following exchange:

COMMISSIONER GIAMMARINO: ...there is sort of a well-established set of suspects. You’ve looked at one.

DR. BOOTH: Correct.

COMMISSIONER GIAMMARINO: So why not look at all?

DR. BOOTH: Two reasons. First of all, with all due respect to the Commission, it’s a question of getting things to the Commission in an understandable way through cross-examination. And KISS works. That a simple way of looking at these things, I think, makes sense. The only time,

for example, I saw a company put forward the Fama French model was before the Gaz Métro. And the witness had a real tough time with the more complicated model. And the Régie was very reluctant to adopt a more complicated model.

COMMISSIONER GIAMMARINO: Right.

DR. BOOTH: So when you get down to conditioning, you're absolutely correct. You think about Chandrell and Ross, and you think about economic factors affecting security returns, you can go to more measures. Does the addition of more measures make the testimony more saleable to a Commission? And the answer to that is generally no. It may make it more saleable in an academic seminar but it's easier, I think, to pick on one thing that people can relate to – credit spreads – that was picked up in most of the hearings in 2009, which seems to make sense, and seems to be consistent with the academic literature, than to go through a more complicated model with term structure, yield parameters, dividend yields or other conditioning variables. So, I pick one, the credit spread. (T8:1658-59)

The Commission Panel accepts that evidence should meet some basic criteria. For example, expert witnesses must have confidence in their estimates; and the evidence must be understandable to the Panel, ideally for all parties involved. The Panel is, however, concerned that experts pay undue attention to prior assessments of the limits of what the Commission will understand and/or accept. While evidence put forward should be as helpful as possible to a Panel dealing with the difficult task of determining the appropriate rate of return and capital structure, it should reflect the expert's best judgment about the state-of-the-art methodology, which should in turn be presented in an understandable way.

It is the Commission Panel's opinion that the purpose of a cost of equity model is to provide structure to the discussion of 'what is a fair rate of return.' Models used to fulfill this purpose provide structure and clarity, and in turn provide a basis for determining the truth of any particular assessment. Models are abstractions and, by definition, imperfect representations. As a result, it is up to the Panel to decide how much confidence it should put in various models that have unrealistic assumptions and do not explain returns perfectly. The Panel must also understand where judgment needs to be applied to the output delivered by these models.

Specifically, in Section 5.2.1, the Panel identified some of the weaknesses related to the adjustments to the CAPM. In particular, the experts expressed reluctance to include additional potential extensions to the CAPM because they were perhaps "too complex" to the Panel. This in turn leaves

open what results other extensions could imply. Similarly, in the beginning of Section 5.2 the Panel identified the lack of global perspective in assessing the investor's portfolio. A more clear set of principles, including a definition of FEI's investors' portfolios (i.e., Global, North American, Canadian) would have been valuable. Accordingly, the Panel invites more comprehensive evidence on these topics in the future.

The Commission Panel believes that one of the roles of the expert is to guide the regulator in evaluating the trade-off between the complexities of the structures needed to evaluate arguments versus the reliability of the structures. This trade-off is at the heart of cost of capital hearings. As this trade-off evolves constantly, the testimony should evolve with it.

8.2 FEI - The Benchmark Utility

Based on the evidence related to long and short-term risk before the Commission Panel we are in agreement with describing FEI as the "benchmark utility" rather than a "low-risk benchmark utility." While the Panel has determined that the level of risk is somewhat less in a number of areas than those which existed at the time of the 2009 Decision, there has been little change in many areas. Therefore, we are of the view that describing FEI as low-risk would not be appropriate. Accordingly, for the purposes of Stage 2 of the GCOC, FEI will be referred to as the benchmark utility. **The common equity component and the approved ROE in this Decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.**

The issue as to whether FEI is a pure-play gas distribution received little direct attention beyond the October 4, 2012 procedural conference. However, the Commission Panel has considered the issue in the context of the level of throughput related to alternative energy initiatives. It appears that FEI's forecasted throughput related to alternative energy initiatives is relatively small. Under cross-examination, FBCU witness, Mr. Stout with reference to natural gas transportation initiatives stated:

"...we forecast two and a half to three petajoules in 2017. I think even if you go to some volume that's in the 10 to 15 petajoule range, it's still less than 10 percent of the throughput of the system, say 5 to 10 percent of the total throughput". (T3:317)

Based on Mr. Stout's testimony, the Commission Panel accepts that FEI at this point in time is primarily a pure-play gas distribution utility.

While Stage 1 of the GCOC proceeding has been mainly concerned with determining an appropriate cost of capital for the benchmark utility, Stage 2 will be primarily concerned with business risk assessment relative to the benchmark. More specifically, public utilities will be called upon to provide evidence as to how they differ from FEI with respect to business risk. The Commission Panel considers that it is feasible that a stand-alone public utility may face overall business risks that are either higher, lower or the same as the benchmark utility.

The primary factors that have influenced FEI's long-term risk have been identified and addressed in Section 4.2. In addition, we have further identified and made determinations upon FEI's short-term risk. In Stage 2 of the GCOC, the public utilities, where appropriate, will be required to describe how they differ from the benchmark utility on these and any other risk factor as it relates to them. In addition, in Section 7.2.5 the Commission Panel has described a risk matrix (included in Appendix E) as a tool for the small utilities (especially the TES utilities) to further assist in justifying their case for an appropriate capital structure and risk premium.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

Original signed by:

D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

R. GIAMMARINO
COMMISSIONER

Original signed by:

M.R. HARLE
COMMISSIONER

Original signed by:

L.A. O'HARA
COMMISSIONER

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER G-75-13**

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**IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473**

and

Generic Cost of Capital Proceeding

BEFORE: D.A. Cote, Commissioner/Panel Chair
M.R. Harle, Commissioner May 10, 2013
L.A. O'Hara, Commissioner
R. Giammarino, Commissioner

O R D E R

WHEREAS:

- A. By Order G-20-12 dated February 28, 2012, the British Columbia Utilities Commission (Commission) established a Generic Cost of Capital (GCOC) proceeding to review: (a) the setting of the appropriate cost of capital for a benchmark low-risk utility; (b) the possible return to a Return on Equity Automatic Adjustment Mechanism (ROE AAM) for setting an ROE for the benchmark low-risk utility; and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt;
- B. Appendix C to Order G-20-12 divided public utilities into two categories for the purpose of the proceeding: "Affected Utilities" and "Other Utilities;"
- C. FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc. and FortisBC Inc. (FortisBC)[collectively (FBCU)]; Corix Multi-Utility Services Inc. (Corix); and Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG) registered as Affected Utilities. The British Columbia Hydro and Power Authority (BC Hydro) and the River District Energy (RDE) registered as Other Utilities;
- D. Among the Interveners who registered for the proceeding, the Association of Major Consumers of BC (AMPC), British Columbia Pensioners' and Seniors' Organization (BCPSO), Commercial Energy Consumers (CEC) [collectively B.C. Utility Customers], and the Industrial Customers Group of FortisBC Inc. (ICG) actively participated;
- E. By Order G-47-12 dated April 18, 2012, the Commission issued the Final Scoping Document for the proceeding. The Scoping Document sets out the purpose and the scope of the proceeding. Matters within the scope of the proceeding included, among others, the appropriate cost of capital and its effective date for a benchmark low-risk utility, the establishment of a benchmark ROE, the consideration of an automatic adjustment mechanism, and the deemed capital structure and deemed cost of capital for small utilities without third-party debt;

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- F. By Order G-50-12 dated April 19, 2012, the Commission, among other matters, set out the further procedural matters to be addressed in the proceeding and a Preliminary Minimum Filing Requirements (MFR) for Affected Utilities document. Parties were invited to make submissions on the Preliminary MFR for Affected Utilities by May 3, 2012, and on the allocation of Participant Assistance/Cost Awards (PACA), PACA eligibility, and/or the Draft Preliminary Regulatory Timetable by May 9, 2012;
- G. By Order G-72-12 dated June 1, 2012, the Commission, among other matters, issued the Final Minimum Filing Requirements for Affected Utilities and the Preliminary Regulatory Timetable for the proceeding;
- H. On June 8, 2012, the Commission released "A Survey of Cost of Capital Practices in Canada" prepared by The Brattle Group for the Commission (Brattle Report). Utilities and Interveners were provided with the opportunity to ask Information Requests on the Brattle Report;
- I. By Order G-84-12 dated June 20, 2012, the Commission amended the Preliminary Regulatory Timetable, establishing, among other things, a Procedural Conference for October 2, 2012 and the commencement date for an oral hearing, if required, on December 12, 2012. The Procedural Conference was subsequently rescheduled to October 4, 2012;
- J. At the Procedural Conference the Commission received, among others, submissions on the following items: (1) the appropriate benchmark utility for the determination of the generic cost of capital; (2) whether a Stage 2 for the purpose of determining an appropriate cost of capital for Affected and Other Utilities to immediately follow Stage 1 was desirable; (3) whether an oral phase was required and (4) the proposed timetable going forward;
- K. By Order G-148-12 dated October 11, 2012, the Commission determined that : (1) FEI in its present pre-amalgamation state, would serve as the benchmark for the proceeding and whether FEI in 2012 is a pure play gas distribution utility would be determined following the hearing of further evidence; (2) a Stage 2 would be added to the proceeding with the schedule to be determined prior to the end of Stage 1; and (3) the review of the proceeding would continue by way of an oral hearing commencing on December 12, 2012;
- L. By Order G-187-12 dated December 10, 2012, the Commission ordered that: (1) the current ROE and capital structure for FEI, the designated benchmark utility, and all regulated entities in B.C. that rely on the benchmark utility, except British Columbia Hydro and Power Authority, are to be maintained and made interim, effective January 1, 2013; and (2) any determinations of the premiums on the benchmark ROE and capital structure of regulated utilities that depend on the benchmark utility for rate setting will be made following the decision in Stage 2; M. The oral public hearing took place over a period of seven days between December 12, 2012 and December 21, 2012. A total of eight witness panels from FBCU and Interveners gave evidence;
- N. FBCU, PNG, Corix, AMPC/CEC, ICG and BCPSO filed Final Submissions. FBCU filed a Reply Submission; and
- O. The Commission has considered the evidence and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-75-13

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NOW THEREFORE, the Commission orders as follows:

1. The common equity component appropriate for the benchmark utility, FEI, effective January 1, 2013 is 38.5 percent.
2. A Return on Equity (ROE) for the benchmark utility, FEI, is established at 8.75 percent effective January 1, 2013.
3. An Automatic Adjustment Mechanism (AAM) formula for annually setting the ROE of the benchmark utility between ROE proceedings is adopted commencing January 1, 2014. The AAM formula will operate until December 31, 2015. The implementation of the model will be subject to conditions outlined in the Decision.
4. FEI is directed to file an application for the review of the common equity component and the ROE approved in Paragraphs 1 and 2 of this Order by no later than November 30, 2015.
5. The common equity component and the ROE approved in Paragraphs 1 and 2 of this Order will continue to serve as the Benchmark cost of capital for any other utility in British Columbia that uses a Benchmark Utility to set rates.
6. Within 30 days of the date of this Order, FEI is to file:
 - (a) a document setting out how and when it will implement the change to its capital structure;
 - (b) amended rate schedules in accordance with paragraphs 1 and 2 of this Order as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013.
7. Small utilities without third-party debt are to include a deemed component of short-term debt of 4 percent.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

APPENDIX A

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LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-1	G-20-12 (Feb 28, 2012)	• Stated purpose in establishing the GCOC proceeding • All regulated utilities determined to be applicants in this proceeding. Utilities are divided into “Affected Utilities” and “Other Utilities.” • Issued initial regulatory timetable for registration of Utilities and Interveners and written submissions on the Preliminary Scoping Document
A-3	G-47-12 (April 18, 2012)	• Issued Final Scoping Document
A-5	G-50-12 (April 19, 2012)	• Issued preliminary Minimum Filing Requirements (MFR) • Issued preliminary regulatory timetable for written submissions on the MFR and the cost allocation of Participant Assistance/Cost Awards (PACA) and PACA eligibility
A-6	G-72-12 (June 1, 2012)	• Issued Final MFR • Determined the principles in the allocation of PACA costs and PACA cost eligibility • Considered expansion of the current proceeding by conducting the GCOC proceeding in two stages • Issued preliminary regulatory timetable for a Procedural Conference and Stage 1 of the GCOC proceeding. • Put on the record the terms of reference for the survey Report carried out by The Brattle Group
A-9	Order G-84-12 (June 20, 2012)	• Issued amended preliminary regulatory timetable

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-16 and A-17	Letter L-52-12 (September 13, 2012)	Established the amended date and agenda for the Procedural Conference
A-22	G-148-12 (October 11, 2012)	- Determined that FEI in 2012 in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding - Determined that a Stage 2 will be added to the proceeding - Determined that review will take place by an oral hearing commencing on December 12, 2012
A-30	G-187-12 (December 10, 2012)	Issued Interim Order establishing current ROE and capital structure for the benchmark utility and all regulated entities in B.C. that rely on the benchmark utility as interim, effective January 1, 2013

LIST OF APPEARANCES

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L. Bussoli	Commission Counsel
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T. Ahmed	FortisBC Utilities
M. Cheesman	Corix Multi-Utility Services Inc. (Corix)
J. Kennedy	Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.
R.B. Wallace, Q.C.	Association of Major Power Customers of B.C. (AMPC)
R. Hobbs	Industrial Customers Group of FortisBC Inc. (ICG)
L. Worth	British Columbia Pensioners' and Seniors' Organization (BCPSO)
E. Kung	British Columbia Pensioners' and Seniors' Organization (BCPSO)
T. Braithwaite	British Columbia Pensioners' and Seniors' Organization (BCPSO)
C. Weafer	Commercial Energy Consumers of British Columbia (CEC)
D. Craig	Commercial Energy Consumers of British Columbia (CEC)
J. Christian	British Columbia Hydro and Power Authority (BC Hydro)
B. Hobkirk	British Columbia Hydro and Power Authority (BC Hydro)
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LIST OF PANELS

FORTISBC INC., FORTISBC ENERGY INC., FORTISBC ENERGY (VANCOUVER ISLAND) INC., AND FORTISBC ENERGY (WHISTLER) INC.

PANEL 1 - COMPANY EVIDENCE

Roger A. Dall'Antonia	Vice President, Strategic Planning, Corporate Development and Regulatory Affairs (Panel Chair)
Douglas Stout	Vice President, Energy Solutions and External Relations
Cynthia Des Brisay	Vice President, Energy Supply and Resource Development
Michele Leeners	Vice President, Finance and CFO

PANEL 2 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

Kathleen C. McShane, MBA, CFA	President Foster Associates, Inc.

PANEL 3 - EXPERT OPINION ON AUTOMATIC ADJUSTMENT MECHANISMS

James M. Coyne	Concentric Advisors

PANEL 4 - EXPERT OPINION ON CAPITAL MARKETS

Aaron M. Engen	Managing Director BMO Capital Markets (Energy Infrastructure Group)

PANEL 5 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

James H. Vander Weide, PhD	Duke University

CORIX MULTI-UTILITY SERVICES INC. (CORIX)

Pauline M. Ahern, MBA	Principal AUS Consultants

LIST OF PANELS

THE INDUSTRIAL CUSTOMERS GROUP OF FORTISBC INC. (ICG)

Andrew Safir, PhD	President
	Recon Research Corporation

THE ASSOCIATION OF MAJOR POWER CUSTOMERS (AMPC), THE COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC), THE BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO), COLLECTIVELY THE BC UTILITY CUSTOMERS

Laurence D. Booth, DBA	University of Toronto

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

British Columbia Utilities Commission
Generic Cost of Capital Proceeding (GCOC) Stage 1

EXHIBIT LIST

Exhibit No.	Description
<i>COMMISSION DOCUMENTS</i>	
A-1	Letter Dated February 28, 2012 and Order G-20-12 – Establishing an initial Regulatory Timetable
A-2	Letter Dated April 17, 2012 – Response clarifying Union Gas’s Intervener Status
A-3	Letter dated April 18, 2012 and Order G-47-2012 – Reasons for Decision and Final Scoping Document
A-4	Letter dated April 18, 2012 – Appointment of Panel
A-5	Letter dated April 19, 2012 - Order G-50-12 List of Further Procedural Matters
A-6	Letter dated June 1, 2012 - Order G-72-12 Issuing Preliminary Timetable, PACA costs, Final Minimum Filing Requirements for Affected Utilities
A-7	Letter dated June 6, 2012 - Request for Variance of Regulatory Timetable Order G-72-12
A-8	Letter dated June 8, 2012 – Commission Consultant’s Survey Report
A-9	Letter dated June 20, 2012 – Order G-84-12 - Amended Preliminary Regulatory Timetable
A-10	Letter dated July 27, 2012 – Request for Comments on the Addition of a Panel Member
A-11	Letter dated August 22, 2012 – Appointment of Commissioner Mr. R. Giammarino
A-12	Letter dated August 31, 2012 – Information Request No. 1 to FortisBC Utilities
A-13	CONFIDENTIAL Letter dated August 31, 2012 – CONFIDENTIAL Information Request No. 1 to FortisBC Utilities
A-14	Letter dated August 31, 2012 – Information Request No. 1 to PNG

Exhibit No.	Description
A-15	Letter dated August 31, 2012 – Information Request No. 1 to Corix
A-16	Letter dated September 13, 2012 – L-52-12 Amending Regulatory Timetable
A-17	Letter dated September 27, 2012 – Agenda for Procedural Conference
A-18	Letter dated October 9, 2012 – Information Request No. 2 to FortisBC Utilities
A-19	CONFIDENTIAL Letter dated October 9, 2012 – CONFIDENTIAL Information Request No. 2 to FortisBC Utilities
A-20	Letter dated October 9, 2012 –Information Request No. 2 to Corix
A-21	Letter dated October 11, 2012 – Order G-148-12 and Reasons for Decision
A-22	Letter dated October 24, 2012 - Request to Access Confidential Material
A-23	Letter dated October 31, 2012 - Access to Confidential Material Response
A-24	Letter dated November 1, 2012 – Confidential Material Access to AMPC (Exhibit C6-11)
A-25	Letter dated November 16, 2012– Information Request No. 1 to ICG on Intervener Evidence
A-26	Letter dated November 16, 2012– Information Request No. 1 to AMPC on Intervener Evidence
A-27	Letter dated November 20, 2012 – Request for submissions
A-28	Letter dated December 3, 2012 – Oral Public Hearing Information
A-29	Letter dated December 5, 2012 – Opening Statements Clarification
A-30	Letter dated December 10, 2012 - Commission Order G-187-12 establishing the current ROE and capital structure
A-31	Letter dated February 14, 2013 – Commission Response to request for extension

Exhibit No.	Description
<i>COMMISSION STAFF DOCUMENTS</i>	
A2-1	Letter Dated February 28, 2012 - Commission Staff Filing British Columbia Utilities Commission letter dated November 28, 2011-Preliminary Notification of Initiation of Generic Cost of Capital Proceeding
A2-2	Letter Dated February 28, 2012 - Commission Staff Filing the Terasen Utilities (December 8, 2010) – Automatic Adjustment Mechanism Review
A2-3	Letter dated June 8, 2012 – Commission Staff Filing the Brattle Group Survey of Cost of Capital Practices in Canada
A2-4	Letter dated July 12, 2012 - Commission Staff Filing Response to AMPC Information Request to Commission Consultants
A2-5	Letter dated July 12, 2012 - Commission Staff Filing Response to FEU Information Request on the Consultants Survey Report
A2-6	Letter dated July 12, 2012 - Commission Staff Filing Response to Industrial Customer Group Information Request on the Consultants Survey Report
A2-7	Letter dated July 12, 2012 - Commission Staff Filing Response to BCOAPO Information Request to Consultants Report
A2-8	Letter dated July 12, 2012 - Commission Staff Filing Response to CEC Information Request to Consultants Report
A2-9	Letter dated July 13, 2012 – Commission Staff Filing BCUC Request for Proposal for a Survey of Canadian Cost of Capital Practice Report
A2-10	Letter dated August 31 2012 – Commission Staff Filing Behavior of the Firm under Regulatory Constraint by Harvey Averch and Leland L. Johnson
A2-11	Letter dated August 31 2012 – Commission Staff Filing Extract from Terasen 2005 and 209 ROE CAP Applications
A2-12	Letter dated August 31 2012 – Commission Staff Filing Extract from FEU 2012-13 Revenue Requirements Decision
A2-13	Letter dated August 31 2012 – Commission Staff Filing Extract from Bloomberg News (Report dated August 6, 2012)

Exhibit No.	Description
A2-14	Letter dated August 31 2012 – Commission Staff Filing Capital Structure - A Comparison
A2-15	Letter dated August 31 2012 – Commission Staff Filing Summaries of Reports and Notes from Recent Credit Rating Agencies and Investment Banks on FEI's Risk and Credit Metrics
A2-16	Letter dated August 31 2012 – Commission Staff Filing Extract from Washington Utilities and Transportation Commission Order 08 Decision
A2-17	Letter dated August 31 2012 – Commission Staff Filing Fitch Affirms National Fuel Gas' IDR at 'A'
A2-18	Letter dated August 31 2012 – Commission Staff Filing The City of Vancouver - District Energy Connectivity Standards Information for Developers
A2-19	Letter dated August 31 2012 – Commission Staff Filing City of Surrey – District Energy System By-law, 2012, No. 17667
A2-20	Letter dated August 31 2012 – Commission Staff Filing Extract from BCUC Information Request No. 2 to River District Energy Limited Partnership
A2-21	Letter dated August 31 2012 – Commission Staff Ontario Energy Board Report of the Board on the Cost of Capital for Ontario's Regulated Utilities December 11, 2009
A2-22	Letter dated August 31 2012 – Commission Staff Filing Ontario Energy Board Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012
A2-23	Letter dated August 31 2012 – Commission Staff Filing Summary of Reports from Recent Credit Rating Agencies and Investment Banks on PNG's Risks and Credit Metrics
A2-24	Letter dated October 9, 2012 – Commission Staff Filing Bradshaw et al. - Playing Favorites
A2-25	Letter dated October 9, 2012 – Commission Staff Filing CTA-Risk-Free Rate Determination
A2-26	Letter dated October 9, 2012 – Commission Staff Filing Exhibit A2-26 OEB Cost of Capital Parameter, May 1 2012

Exhibit No.	Description
A2-27	Letter dated November 16, 2012 - Commission Staff Filing Cost of Capital by Sector_NYU_Value Line Database
A2-28	Letter dated November 16, 2012 - Commission Staff Filing Gau, Thompson 2012 Capitalization Rate Study
A2-29	Letter dated November 16, 2012 - Commission Staff Filing Schaeffler and Weber- The Cost of Equity of Network Operators
A2-30	Letter dated November 16, 2012 - Commission Staff Filing TD-Long-Term Returns October 2012
A2-31	Letter dated November 16, 2012 - Commission Staff Filing Ashton et al- Analysts' Optimism in Earnings Forecasts
A2-32	Letter dated November 16, 2012 - Commission Staff Filing Understanding Corporate Bond Spreads Using Credit Default Swaps
A2-33	Submitted at Oral Hearing December 12, 2012 – Commission Staff Filing FEU 2012-2013 Revenue Requirements G-44-12 Compliance Filing
A2-33-1	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing page 1 of letter dated may 1, 2012 to BCUC from FortisBC, with two pages attached
A2-34	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Vancouver Sun Article Natural gas seen as green fuel
A2-35	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Staff Witness Aid
A2-36	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing pages 7 to 10 from Standard & Poors Report
A2-37	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Long-Term Economic Forecast, TD Economics, September 18, 2012
A2-38	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Attachment 8.2(A), page 17 of 18, Results of Differences in Systematic Risk
A2-39	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Extract from Order No. 09-176 from Public Utility Commission of Oregon

Exhibit No.	Description
A2-40	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Rating Report, February 29, 2012 from DBRS
A2-41	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Document Headed Moody's Investors Service, Credit Opinion: FortisBC Energy Inc.
A2-42	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Five-Page Document, First Page Headed Returns on Average Common Stock Equity for Sample of U.S. Utilities
A2-43	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Approaches to Estimating the Deemed Interest Rate for Long Term Debt
A2-44	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Excerpt of FEI Kelowna DES CPCN Application
A2-45	Submitted at Oral Hearing December 17, 2012 – Document Headed Credit Rating and Equity Risk Premium
A2-46	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Weathering the Headwinds to Canada's Economic Growth 21 November 2012
A2-47	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Puget Sound Energy Inc.
A2-48	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Power & Utilities Research, the One-Two Punch: Growth Combined with Attractive Yield
A2-48-1	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Extract from BMO Capital Markets, page 11, Headed Power & Utilities
A2-49	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Ontario Energy Board, Report of Board, December 20, 2006
A2-50	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First
A2-51	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Witness Aid Prepared by Commission Staff Entitled Informed Expert Judgment

Exhibit No.	Description
<i>AFFECTED UTILITIES DOCUMENTS</i>	
B1-1	BC UTILITIES OF FORTIS INC. COMPRISED OF FORTISBC ENERGY INC., FORTISBC ENERGY VANCOUVER ISLAND INC., FORTISBC ENERGY WHISTLER INC. AND FORTISBC INC. (FBCU) Letter Dated March 15, 2012 – Notice of Registration
B1-2	Letter Dated March 21, 2012 – FBCU Submission on the Preliminary Scoping Document
B1-3	Letter Dated May 3, 2012 – FBCU Submission on Minimum Filing Requirements
B1-4	Letter Dated May 9, 2012 – FBCU Submission regarding Order G-50-12 Appendix A
B1-5	Letter Dated June 5, 2012 – FBCU Submitting Request for Variance of Preliminary Regulatory Timetable
B1-6	Letter Dated June 5, 2012 – FBCU Reply Submissions regarding Request for Variance of Preliminary Regulatory Timetable
B1-7	Letter Dated June 22, 2012 – FBCU Submitting Information Request regarding the Commission Consultant Survey Report
B1-8	Letter Dated August 2, 2012 – FBCU Submitting comments regarding the addition of a panel member
B1-9	Letter Dated August 3, 2012 – FBCU Submitting Evidence
B1-9-1	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 1 to 2
B1-9-2	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3A – Debt Investment Analyst Reports for FEI
B1-9-3	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Beacon to Credit Suisse
B1-9-4	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Macquarie to UBS

Exhibit No.	Description
B1-9-5	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 4 to 11
B1-9-6	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendices B to J
B1-9-7	CONFIDENTIAL Letter Dated August 3, 2012 – FBCU Submitting Evidence CONFIDENTIAL Appendices
B1-10	Letter Dated September 24, 2012 – FBCU Submitting Response to BCPSO IR No. 1
B1-11	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – FBCU
B1-12	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – A. Engen
B1-13	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Concentric
B1-14	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Dr. Vander Weide
B1-15	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – K. McShane
B1-16	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – A. Engen
B1-17	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Concentric
B1-18	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Dr. Vander Weide
B1-19	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – K. McShane
B1-20	Letter Dated September 24, 2012 – FBCU Response to BCUC IR No.1
B1-20-1	CONFIDENTIAL Letter Dated September 24, 2012 – FBCU Confidential Response to BCUC IR No.1
B1-21	CONFIDENTIAL Letter Dated September 24, 2012 – FBCU Response to Confidential BCUC IR No.1

Exhibit No.	Description
B1-22	Submitted at Procedural Conference Letter Dated October 3, 2012 – FBCU Counsel's Oral Submissions
B1-23	Letter dated October 26, 2012 – FBCU Response to Confidentiality Request
B1-24	Letter dated October 29, 2012 – FBCU Response to BCUC IR No. 2
B1-25	CONFIDENTIAL Letter dated October 29, 2012 – FBCU Response to BCUC Confidential IR No. 2
B1-26	Letter dated October 29, 2012 – FBCU Response to BCPSO IR No. 2
B1-27	Letter dated November 2, 2012 – FBCU Comments regarding Confidential Material Access
B1-28	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to AMPC/BC Utility Customers on the Evidence of Dr. Booth
B1-29	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to ICG on the Evidence of Dr. Safir
B1-30	Letter Dated November 23, 2012 – FBCU Submission on Interim Rates Jan 1, 2013
B1-31	Letter Dated November 30, 2012 – FBCU Submitting Witness Panels and Direct Testimony
B1-32	Letter dated December 6, 2012 – FBCU Submitting Rebuttal Evidence
B1-33	Letter dated December 10, 2012 – FBCU Submitting Opening Statement
B1-34	Submitted at Oral Hearing December 12, 2012 – FBCU Written Opening Statement of Counsel
B1-35	Submitted at Oral Hearing December 12, 2012 – FBCU Revised: Exhibit B1-9-6, Appendix H, page 51, Figure 34
B1-36	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 1
B1-37	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 2
B1-38	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 3

Exhibit No.	Description
B1-39	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 4
B1-40	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 5
B1-41	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 6
B1-42	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 7
B1-43	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 8
B1-44	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 9
B1-45	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 10
B1-46	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 11
B1-47	Submitted at Oral Hearing December 14, 2012 – FBCU Filing Testimony of Kathleen C. McShane Tab 2
B1-48	Submitted at Oral Hearing December 17, 2012 – FBCU Undertaking No. 12
B1-49	Submitted at Oral Hearing December 18, 2012 – FBCU Filing Testimony Figures Update
B1-49-1	Letter received January 3, 2013 – FBCU Filing Remaining Chart Updates
B1-50	Submitted at Oral Hearing December 19, 2012 – FBCU Filing 104 page Collection of Documents Used in Cross Examination of Dr. Booth
B1-51	Submitted at Oral Hearing December 21, 2012 – FBCU Filing Compendium of Extracts, First Page Entitled Fair Return for Terasen Gas Inc. (TGI) August 2009
B1-52	Letter received January 3, 2013 – FBCU Undertaking No. 13
B1-53	Letter received January 3, 2013 – FBCU Undertaking No. 14
B1-54	Letter received January 3, 2013 – FBCU Undertaking No. 15
B1-55	Letter received January 3, 2013 – FBCU Undertaking No. 16
B1-56	Letter received January 3, 2013 – FBCU Undertaking No. 17
B1-57	Letter received January 3, 2013 – FBCU Undertaking No. 18

Exhibit No.	Description
B1-58	Letter received January 3, 2013 – FBCU Undertaking No. 19
B1-59	Letter received January 3, 2013 – FBCU Undertaking No. 20
B1-60	Letter received January 29, 2013 – FBCU Undertaking No. 21
B1-61	Letter received January 29, 2013 – FBCU Undertaking No. 22
B1-62	Letter received January 29, 2013 – FBCU Undertaking No. 23
B1-63	Letter received January 29, 2013 – FBCU Undertaking No. 24
B1-64	Letter received January 29, 2013 – FBCU Undertaking No. 25
B1-65	Letter received January 29, 2013 – FBCU Undertaking No. 26
B1-66	Letter received January 29, 2013 – FBCU Undertaking No. 27
B1-67	Letter received January 29, 2013 – FBCU Undertaking No. 28
B1-68	Letter received January 29, 2013 – FBCU Undertaking No. 29
B2-1	CORIX MULTI-UTILITY SERVICES INC. (CORIX) Letter Dated March 14, 2012 – Notice of Registration
B2-2	Letter Dated March 21, 2012 – Corix Submission on the Preliminary Scoping Document
B2-3	Letter Dated May 3, 2012 – Corix Submission on Minimum Filing Requirements
B2-4	Letter Dated May 9, 2012 – Corix Submission regarding Order G-50-12 Appendix A
B2-5	Letter Dated June 8, 2012 – Corix Submission on FBCU Request for Variance
B2-6	Letter Dated August 3, 2012 – Corix Submitting Comments Regarding the Addition of a Panel Member
B2-7	Letter Dated August 3, 2012 – Corix Submitting Evidence
B2-8	Letter Dated September 24, 2012 – Corix Submitting Response to BCPSO IR No. 1
B2-9	Letter Dated September 24, 2012 – Corix Submitting Response to BCUC IR No. 1

Exhibit No.	Description
B2-10	Letter Dated October 18, 2012 – Corix Submitting Response to BCUC IR No. 2
B2-11	Letter Dated November 23, 2012 – Corix Submission regarding A-27
B2-12	Submitted at Oral Hearing December 18, 2012 – Corix Filing Opening Remarks of Counsel for Corix Multi-Utility Services Inc., December 12, 2012
B2-13	Submitted December 24, 2012 – Corix Filing Undertaking Document Titled Before the Florida Public Service Commission
B2-14	Submitted December 24, 2012 – Corix Filing Undertaking Document titled Comparison of Business Risk Adjustments in Cost of Capital Testimony Filed by Ms. Pauline M. Ahern
B2-15	Letter received January 3, 2013 - Corix Filing Response to Undertaking
B3-1	PACIFIC NORTHERN GAS LTD. AND PACIFIC NORTHERN GAS N.E. LTD. (PNG) Online Registration Dated March 16, 2012 – Notice of Registration
B3-2	Letter Dated March 21, 2012 – PNG Submission on the Preliminary Scoping Document
B3-3	Letter Dated May 3, 2012 – PNG Submission on Minimum Filing Requirements
B3-4	Letter Dated May 9, 2012 – PNG Submission Regarding Order G-50-12 Appendix A
B3-5	Letter Dated June 8, 2012 – PNG Submission Regarding Variance of the Regulatory Timetable
B3-6	Letter Dated August 3, 2012 – PNG Submitting Comments Regarding the Addition of a Panel Member
B3-7	Letter Dated August 3, 2012 – PNG Submitting Evidence
B3-8	Letter Dated September 24, 2012 – PNG Submitting Response to BCUC IR No. 1
B3-9	Letter Dated September 24, 2012 – PNG Submitting Response to BCPSO
B3-10	Letter Dated September 24, 2012 – PNG Submitting Response to AMPC, BCPSO and CEC
B3-11	Letter Dated November 23, 2012 – PNG Submission Regarding A-27

Exhibit No.	Description
B3-12	Letter Dated November 30, 2012 – PNG Submitting Comments regarding Witness Panels

OTHER UTILITIES DOCUMENTS

B4-1	BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH) Letter Dated March 12, 2012 – Notice of Registration
B4-2	Letter Dated March 21, 2012 – BCH Submission on the Preliminary Scoping Document
B4-3	Letter Dated May 3, 2012 – BCH Submission on Minimum Filing Requirements
B4-4	Letter Dated May 9, 2012 – BCH Submission Regarding Order G-50-12 Appendix A
B4-5	Letter Dated June 8, 2012 – BCH Submission Regarding variance of the Regulatory Timetable
B4-6	Letter Dated August 3, 2012 – BCH Submitting Comments Regarding the Addition of a Panel Member
B4-7	Letter Dated November 23, 2012 - BCH Submission Regarding A-27
B4-8	Letter Dated November 30, 2012 – BCH Submitting Comments Regarding Witness Panels
B5-1	RIVER DISTRICT ENERGY (RDE) Letter Dated March 12, 2012 – Notice of Registration

INTERVENER DOCUMENTS

C1-1	UNION GAS LIMITED (UG) Letter dated March 5, 2012 – Request for Intervener Status by Patrick McMahon
C2-1	CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378) Letter dated March 15, 2012 – Request for Intervener Status by James Quail
C2-1-1	Letter dated March 20, 2012 – COPE 378 Submitting Intervention Supplementary Comments
C2-2	Letter dated April 19, 2012 - COPE 378 Submitting Updating Consultant details
C2-3	Letter dated June 26, 2012 - COPE 378 Submitting Updating Consultant Information

Exhibit No.	Description
C3-1	SENTINEL ENERGY MANAGEMENT (SEM) Online Registration dated March 20, 2012 – Request for Intervener Status by Jim Langley
C4-1	INDUSTRIAL CUSTOMERS GROUP (ICG) Letter dated March 20, 2012 Via Email – Request for Intervener Status by Robert Hobbs and Brian Merwin
C4-2	Letter Dated March 21, 2012 – ICG Submission on the Preliminary Scoping Document
C4-3	Letter Dated May 3, 2012 – ICG Submission regarding the Preliminary Minimum Filing Requirements for Affected Utilities
C4-4	Letter Dated May 9, 2012 – ICG Submission Regarding Order G-50-12 Appendix A
C4-5	Letter Dated June 8, 2012 – ICG Submission regarding Variance of the Regulatory Timetable
C4-6	Letter Dated June 21, 2012 – ICG Submitting Information Request Regarding the Commission Consultant Survey Report
C4-7	Letter Dated August 31, 2012 – ICG Submitting Information Request No. 1
C4-8	Letter Dated October 24, 2012 - ICG Submitting Comments regarding Request for Confidential Information
C4-9	Letter dated November 5, 2012 – ICG Submitting Evidence
C4-10	Letter dated November 6, 2012 – ICG Submitting Confidential Undertakings
C4-11	Letter dated November 30, 2012 – ICG Submitting Responses to Information Request No. 1
C4-12	Letter dated November 30, 2012 – ICG Submission Regarding Exhibit A-27
C4-13	Submitted at Oral Hearing December 12, 2012 – ICG Opening Comments
C4-14	Submitted at Oral Hearing December 14, 2012 – ICG Filing Tab 2 Testimony of Kathleen C. McShane
C4-15	Submitted at Oral Hearing December 17, 2012 – ICG Filing Opening Statement of Dr. Andrew Safir

Exhibit No.	Description
C4-16	Letter dated January 14, 2013 – ICG Submitting Undertakings
C4-17	Letter dated January 25, 2013 – ICG Submitting Dr. Lawrence Booth Undertaking No. 2
C5-1	BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL) (previously BC Old Age Pensioner' Organization <i>et. al.</i>) VIA EMAIL - Letter Dated March 20, 2012 – Request for Intervener Status by Leigha Worth, Tannis Braithwaite and Bill Harper
C5-2	Letter Dated March 21, 2012 – BCOAPO Submission on the Preliminary Scoping Document
C5-3	Letter Dated May 3, 2012 – BCOAPO Submission on Minimum Filing Requirements
C5-4	Letter Dated May 9, 2012 – BCOAPO Submission Regarding Order G-50-12 Appendix A
C5-5	Letter Dated June 8, 2012 – BCOAPO Submission Regarding Variance of the Regulatory Timetable
C5-6	Letter Dated June 22, 2012 – BCOAPO Submitting Information Request Regarding the Commission Consultant Survey Report
C5-7	Letter dated July 23, 2012 – BCOAPO Submitting Notice of Name Change to British Columbia Pensioners' and Seniors' Organization (BCPSO)
C5-8	Letter Dated August 3, 2012 – BCPSO Submitting Comments Regarding the Addition of a Panel Member
C5-9	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to Corix
C5-10	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to FBCU
C5-11	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to PNG
C5-12	Letter Dated October 9, 2012 - BCPSO Submitting Information Request No. 2 to FBCU

Exhibit No.	Description
C5-13	Letter Dated October 9, 2012 - BCPSO Submitting Contact Update
C5-14	Letter Dated November 30, 2012 - BCPSO Submission Regarding Exhibit A-27
C5-15	Submitted at Oral Hearing December 17, 2012 – BCPSO Filing Business Spectator Document
C6-1	ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC) Letter Dated March 20, 2012 – Request for Intervener Status by Richard Stout and Lloyd Guenther
C6-2	Letter Dated May 2, 2012 – AMPC Submitting Contact Update
C6-3	Letter Dated May 3, 2012 – AMPC Submission on Minimum Filing Requirements
C6-4	Letter Dated May 9, 2012 – AMPC Submission Regarding Order G-50-12 Appendix A
C6-5	Letter Dated June 8, 2012 – AMPC Submission Regarding Variance of the Regulatory Timetable
C6-6	Letter Dated June 22, 2012 – AMPC Submitting Information Request Regarding the Commission Consultant Survey Report
C6-7	Letter Dated August 3, 2012 – AMPC Submitting Comments Regarding the Addition of a Panel Member
C6-8	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU
C6-9	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-9-1	Letter Dated September 23, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Corrected Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-10	Letter Dated October 22, 2012 - AMPC Filing a Request for Confidential Information
C6-11	Letter Dated October 31, 2012 - AMPC Submitting Comments regarding Access to Confidential Information
C6-12	Letter dated November 5, 2012 – AMPC Submitting Evidence

Exhibit No.	Description
C6-13	Letter dated November 5, 2012 – AMPC Submitting Confidential Undertakings
C6-14	Letter dated November 30, 2012 – AMPC Submission regarding Exhibit A-27
C6-15	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to BCUC
C6-16	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to FBCU
C6-17	Submitted at Oral Hearing December 12, 2012 – AMPC Filing BC Natural Gas Strategy Fueling BC's Economy for the Next Decade and Beyond
C6-18	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 17d
C6-19	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 21 i
C6-20	Submitted at Oral Hearing December 17, 2012 – AMPC filing Alberta Utilities Commission 2009 Generic Cost of Capital Proceeding Direct Testimony of James M. Coyne
C6-21	Submitted at Oral Hearing December 18, 2012 – AMPC Filing Witness Aid Prepared by BC Utilities Customers
C6-22	Submitted at Oral Hearing December 19, 2012 – AMPC filing Dr. Booth's Opening Statement
C6-23	Letter dated January 18, 2013 – AMPC Submitting Dr. Booth Undertaking No. 1
C6-24	Letter Dated February 14, 2013 – AMPC Submitting Extension Request
C7-1	COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC) Letter Dated March 20, 2012 – Request for Intervener Status by Christopher Weafer
C7-2	Letter Dated May 9, 2012 – CEC Submission Regarding Order G-50-12 Appendix A
C7-3	Letter Dated June 8, 2012 – CEC Submission Regarding variance of the Regulatory Timetable

Exhibit No.	Description
C7-4	Letter dated June 25, 2012 – CEC Submitting Information Request Regarding the Commission Consultant Survey Report
C7-5	Letter Dated August 3, 2012 – CEC Submitting Comments Regarding the Addition of a Panel Member
C7-6	Letter dated November 9, 2012 – CEC Submitting Confidential Undertakings

INTERESTED PARTY DOCUMENTS

D-1	AT BUSINESS CONSULTING (ATB) Online Registration dated May 9, 2012 – Request for Interested Party Status by Anastasios Tsalamandris

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
	Capital structure (debt/equity ratio)	60/40 (actual)	60/40 (actual)	60/40 (actual; proposed)		60/40 (actual)	Deemed 60/40	Deemed 60/40	Deemed 60/40
	Equity Risk Premium	N/A	0 bps (approved)	50 bps (proposed)		50 bps (approved)	50 bps (approved)	100 bps (approved)	50 bps (approved)
1	Technology risk/system performance risk associated with chosen technologies	Natural Gas: proven technology	Geo-exchange loop field system and heat recovery with high efficiency natural gas boilers equipment	Recovered waste heat from TELUS Data Centre with peaking and redundant backup heat supplied by Centre Heat Distribution Ltd.: low risk	Slightly higher for PCI / TG than FEI NG	High efficiency condensing boilers: proven technology; Ground source heat pumps; less established technology	Natural gas boilers proven technology	Biomass Gasification innovative technology; Natural Gas boilers; proven technology (while DGE not yet on biomass, the Commission approved the technology)	Natural Gas: boiler: proven technology

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
2	Fuel Risk cost and availability	Natural gas: Low- medium	Low risk: free energy from ground and heat recovery, but cost risk for electricity used to operate heat pumps and TES equipment, and for natural gas for supplementary heat and peaking	Data Centre that supplies waste heat is assumed to be available throughout the 20 year term of the analysis: low risk Data Centre ceases operation	Lower for PCI / TG than FEI NG	Natural gas and electricity: Low- medium; Heat from ground: low (some energy cost risk in electricity costs to operate GSHPs)	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant	Biomass: medium- high; natural gas; low-medium	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant
3	Customer Base (e.g., diversity, certainty, growing, declining)	Established and diverse customer base but very slow growth	Greenfield utility four types of customers	Not large customer base or significant diversity: low risk	Higher for PCI / TG than FEI NG (NG has much greater diversity)	Established customer: low risk	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out
4	Default risk of customer	Minimal	Minimal	Minimal	Similar for PCI / TG as for FEI NG	Minimal as SD has budget constraints as well	Minimal	Minimal	Minimal

**ORDER C-1-13
ATTACHMENT B**

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
5	Property development risk	Medium to high: there are competing energy options	Low risk: all customers bound by agreement	Majority of tenants committed but customers can still leave: low risk	Lower for PCI / TG than FEI NG	None, as not a new development	Low: phased approach to capital deployment	High: build first approach to capital deployment	Low: phased approach to capital deployment
6	Developer / customer connection risk	Medium to high: due to building stock changes and competitive energy sources	Low Risk: customers will connect on occupancy	Low Risk: customers will connect on occupancy	Lower for PCI / TG than FEI NG	Low, as one known customer with existing sites	Low: mandatory connection	Low: mandatory connection	Low: mandatory connection
7	Load Forecast Uncertainty	Minimal in the short term, as mature utility with deferral account; somewhat higher in the long term	Inherent uncertainty in load forecast	FAES proposes to take forecast risk on actual energy throughput versus forecast for 5 year period: Low-medium	Higher for PCI / TG than FEI NG	Low, as established energy load	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast

**ORDER C-1-13
ATTACHMENT B**

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
8	Utility size	Large and mature utility	Project is carried out by a separate corporate entity, Small development specific utility.	Project is carried out by separate corporate entity, Small development specific utility.	Higher for PCI / TG than FEI NG	Project is carried out by separate corporate entity	Small development specific utility	Small development specific utility	Small development specific utility
9	Initial construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
10	Future Construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
11	Operating cost risk	Minimal as revenue requirement application to recover costs	Minimal as mechanism in place to recover costs	Low-medium risk: as deferral accounts do not cover all O&M variances between forecast and actual	Higher for TG, similar for PCI relative to FEI NG	Minimal as mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
12	Public Acceptance Risk	Medium as natural gas is an established and widely used technology but public perceives it as less than clean	Low as seen as green alternative	Low	Lower for PCI / TG than FEI NG	Low as seen as green alternative	Low as seen as a green alternative	Low as gasification technology part of approval process for the development and already selected at the time of the CPCN application	low as seen as a green alternative
13	Fixed/Variable rate design	15% fixed/85% variable	~~400% variable~~ Rate Design Not Approved	100% variable (volume rate)	Higher for TG, relative to FEI NG PCI Rate Design not Approved	100% variable	60% fixed/40% variable	50% fixed/50% variable	66% fixed / 34% variable

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14	Levelized approach to rates	No	~~Only in first three years then transition to cost of service~~ Rate Design not Approved	The rates charged for the first five years have been mutually agreed upon using a benchmark based on BC Hydro RIB Step 1 and Step 2	Slightly higher for TG, relative to FEI NG PCI Rate Design Not Approved	No, transitional market rate and deferral account	Yes	Yes	Yes
15	Financial risk	Low-medium: appropriate standalone financing structure for capital markets	Medium (similar to DSD)	Forecast risk and rates fixed for first five years (other than one-time adjustment for GCOC changes) impacts financial risk: medium risk justifies 50 bps on FEI utility benchmark	Higher for PCI / TG than FEI NG	Medium	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility

**ORDER C-1-13
ATTACHMENT B**

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
16	Competitive challenges	Competitive with electricity and competition from alternative energy providers	Other TES providers and electricity	Other TES providers and electricity	Lower for PCI / TG than FEI NG	Other TES providers and electricity	Other utilities and electricity	Other utilities and electricity	Other utilities and electricity
17	Provincial climate change and energy policies	Encourage reduction of fossil fuels usage to reduce GHG emissions and lower energy use.	Favourable government policies	Favourable government policies	Lower for PCI / TG than FEI NG	Favorable govt. policies	Favourable govt. policies	Favourable govt. policies	Favourable govt. policies
18	Regulatory uncertainty	Low to medium: uncertainty exists for service offerings within the natural gas class of service.	Medium risk: New, uncertainty, scrutiny and not streamlined Rate Design Denied as Applied	Medium risk: New, uncertainty, scrutiny and not streamlined	Higher for PCI / TG than FEI NG	Medium risk: new, uncertainty, scrutiny and not streamlined	Medium risk: New, uncertainty, scrutiny, alternative energy centre not yet approved	Medium risk: New, uncertainty, scrutiny	Medium risk: New, uncertainty, scrutiny

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ATTACHMENT B**

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
19	Business Development Risk	Minimal	Low – deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1.) [Shareholder ultimately at risk for the TESDA]	FAES has agreed to purchase the TGTES from the Partnership upon commissioning for actual construction cost of \$7.9 million up to a maximum of 30% above the \$7.9 million estimate.	Higher for PCI / TG than FEI NG	Low: deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1) (Shareholder ultimately at risk for the TESDA)	High as part of overhead cots	High as part of overhead cots	High as part of overhead cots

COST OF CAPITAL ESTIMATION MODELS AND KEY INPUTS

DISCOUNTED CASH FLOW MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
McShane	Constant Growth	12 US utilities	4.9% - Average of consensus earnings forecasts from Bloomberg, Reuters, ValueLine and Zacks.	9.3	McShane Evid, Table 30, p. 113; App. C, and Schedule 19
	Constant Growth	5 Can utilities (incl. Fortis Inc.)	7.5% - Reuters L-T EPS forecasts	11.0	McShane Evid, Table 30, p. 113 and Schedule 22
	Sustainable Growth	12 US Utilities	4.4% - Avg of sustainable growth rates for US utilities derived from Value Line forecasts of ROEs, earnings retention rates and earnings growth from external financing.	8.7	McShane Evid, Table 30, p. 113 and Schedule 20
	Three Stage Model	5 Can utilities (incl. Fortis Inc.)	Stage 1 (yrs 1-5) - Reuters L-T EPS forecasts: 7.5% Stage 2 (yrs 6-10)- Avg of stages 1 and 3: 5.9% Stage 3 (yrs 11+)-GDP growth: 4.3%	8.6	McShane Evid, Table 30, p. 113 App. C and Schedule 23
	Three Stage Model	12 US utilities	Stage 1 (yrs 1-5) - Avg of all EPS forecasts: 4.9% Stage 2 (yrs 6-10) - Avg of stages 1 and 3: 4.9% Stage 3 (yrs 11+) - GDP growth: 4.9%	9.2	McShane Evid, Table 30, p. 113 and Schedule 21
	Mid-point of range	Canadian sample		9.8	McShane Evid. p. 113
	Mid-point of range	Both samples		9.4	McShane Evid. p. 113
			Bare bones Cost of Equity estimated at 9.4% and add Financing Flexibility Adjustment of 0.5%	9.9	

...DCF MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Vander Weide	Quarterly DCF model	Comprehensive group of 32 US utilities	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.8	VdW Evid, p. 28 – 30 and Exhibit 6
		Small group of 19 US utilities (subset of large group)	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.5	VdW Evid, p. 28 – 30 and Exhibit 7
			Bare-bones cost of equity for the Comprehensive Model 9.8% plus Financing Flexibility	10.3	
			Bare-bones cost of equity for the Small Utilities Model 9.5% plus Financing Flexibility	10.0	
			Summary of results from DCF	10.15	
Booth		All of Canadian market	Growth rate range 4.7% - 6.1% based on multiplying corporate Canada ROEs since 1987 times retention rates.	9.3	Booth Evid., p. 94 & App D, p. 9-10
		US market – S&P 500	Growth rate range of 6.79% - 7.97% based on multiplying the average and median values respectively for S&P 500 ROEs since 1977 times the current dividend yield	Calculated range: 8.93-10.01. Adjusted range: 9.5-10.5	Booth Evid., App D, p. 10-13 (Note disc. of analyst forecasts at p. 14-17.)

...DCF MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Safir	Two-stage model	Canadian Sample - 5 Can. utilities (incl. Fortis)	Stage 1 (analyst forecasts)- 7.49%; Stage 2 (GDP growth) – 4.49% Weighted average (33/67): 5.49%	8.99	Safir Evid, p. 24-26, and Schedule 3
	Two-stage model	US Sample – 18 US utilities	Stage 1 (analyst forecasts) - 5.50%; Stage 2 (GDP growth) – 4.57% Weighted average (33/67): 4.88%	8.86	Safir Evid,p. 24-26, and Schedule 4
			ROE Adjusted by Flotation Costs at 5% for Canadian sample	9.46	Safir Evid. p. 26
			ROE Adjusted by Flotation Costs at 5% for US sample	9.33	Safir Evid. p. 26

CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	See her Risk-Adjusted Equity Risk Premium Model					
Vander Weide	N/A – Vander Weide recommends placing no weight on CAPM results	2.95% forecast yield to maturity on L-C bonds	6.6% - Ibbotson SBBI estimate of risk premium on market portfolio – diff. between arithmetic mean return on S&P 500 vs. income return on 20-year Treasury bonds. (1937-2012)	0.73 – Average Value Line beta for his large proxy US utility group.	8.27 (including financial flexibility)	Vander Weide Evid, pp. 38-44; Exhibits 12 to 15
				0.92 – historical ratio of the average utility risk premium to the S&P risk premium	9.52 (including financial flexibility)	
Booth	Simple CAPM estimate	3.00% (Base adjusted LTC forecast)	Range: 5.0 – 6.0%	Range: 0.45-0.55	Range: 5.75-6.80, including 0.50 flotation cost allowance	Booth Evid, p. 74 & 75; App. B (MRP), p. 16, App. C (beta est), pp. 10-14
	Adjusted CAPM (Simple CAPM plus 0.40 for credit spread and 0.80 for Operation Twist.	3.80% (Base adjusted LTC forecast)	Same as above	Same as above	Range: 6.95 to 8.00 (2013) 7.00 -8.00 Including flotation cost allowance	Booth Evid, p. 85, 93-94 (adjustments); other values same as above.
				Point estimate for CAPM	7.5	Booth Evid. p. 95

...CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
Safir	Canadian CAPM	4.00%	5.96% (Total mkt. return minus the est annual long bond income return (both 1924-2010))	Adjusted beta: 0.36 (weighted 0.67 raw + 0.33 mkt tendency) Calculated raw beta (Sched 1): 0.25 Long-run mkt tendency beta (Schaeffler & Weber survey): 0.58	6.15	Safir Evid. p. 12-15 and Schedule 1
	US CAPM	4.50%	6.62% (Total mkt. return minus the est annual long bond income return (both 1926-2011))	Adjusted beta: 0.48 (weighted 0.67 raw + 0.33 market tendency) Calculated raw beta (Schedule 2): 0.43 Long-run market tendency beta (Schaeffler & Weber survey): 0.58	7.68	Safir Evid. p. 18 and Schedule 2
				Adjusted by flotation cost allowance of 0.32% for the Canadian ROE estimate	6.47	Safir Evid. p. 12
				Adjusted by flotation cost allowance of 0.40% for the US ROE estimate	8.08	Safir Evid. p. 18

EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	Risk-adjusted ERP (variant of CAPM)	4.0% (forecast 30 yr Long-Can bond yield)	7.25-7.5% (based on bond income returns < 8.0%; table 12, pp. 82, 98 of her evid)	0.65-0.70 adjusted (0.65 based on Bloomberg adjusted betas for 5 Can utilities or raw beta for TSX utilities index adjusted per Bloomberg (.67 raw+0.33; see McShane evid. p. 97. For upper end of range see table 21, p. 98)	Range: 8.9-9.1% Est. 9.0%	McShane Evidence, p. 98
	<i>DCF Based ERP Models: 1998-2012 Q1 US Sample</i>					
	Constant Growth – Single variable (L-C bond rate)	4.0% (forecast 30 yr L-C yield)	5.7% at 4.0% risk free rate (see table 22, p. 100)	N/A	9.7%	McShane evid. p. 99-101
	3-stage growth - single variable	4.0%	5.7 or 5.8% at 4.0 risk free rate (apparent inconsistency between tables 24 and 25)	N/A	9.7	McShane evid p. 99-105
	Constant Growth – two variable (L-C bonds and 30 year A-rated utility yield spreads)	4.0%	5.5%	N/A	9.5	McShane evid at pp. 102-105, esp. table 25.
(cont....)	3-stage growth – two variable	4.0%	5.6%	N/A	9.6	McShane evid at pp. 102-105, esp. table 25.

...EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane (cont. from previous page)	<i>DCF Based ERP Models: 1998-2012Q1 US Sample (continued from previous page)</i>					
	Quarterly US utility ROE's as proxy for utility cost of equity – single variable	4.0%	6.2%		10.2 (McShane gives no weight)	McShane evid at pp. 102-105, esp. table 25
	Quarterly US utility ROE's – two variable	4.0%	6.1%		10.1 (no weight)	McShane evid at pp. 102-105, esp. table 25
	Constant Growth over A-rated bond	5.35% (4.0% L-C bond yield + 135 bp)	4.0		9.4	McShane evid at p. 105, table 26
	3-stage growth over A-rated bond	5.35% (as above)	4.2		9.6	McShane evid at p. 105, table 26
	Allowed ROEs over A-rated bond	5.35% (as above)	4.8		10.2 (no weight)	McShane evid at p. 105, table 26
	Summary of results DCF based results	4.0%% (f'cast L-C bond yields) or 5.35% (A-rated utility bond yields)	Range of regression results		9.4 – 9.7	McShane Evid. p. 106
(cont...)			Bare bones Cost of Equity (mid-point)		9.6	

...EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Equity Returns	Bond Inc. Returns	Utility Risk Premium	Change in Bond Yield/Ret	Change in Util Risk Pr.	Utility Equity Risk	ROE est. (%)	References
McShane (cont. from previous page)	Historic Utility ERP- Can utilities (1956-2011)	4.0%	12.1%	7.3%	4.8%	-3.3%	+1.6%	6.4%	10.5 (based on all 3 Historic Utility ERP tests)	McShane Evid. pp. 106-108
	Historic Utility ERP- US Gas Utilities (1947-2011)	4.0%	11.9%	5.9%	6.0%	-1.9%	+1.0%	7.0%		McShane Evid. pp. 106-108
	Historic Utility ERP- US Elec Utilities (1947-2011)	4.0%	11.0%	5.9%	5.1%	-1.9%	+1.0%	6.2%		McShane Evid. pp. 106-108
	Summary of All Risk Premium Tests	Risk-Adjusted Equity Market							9.0	McShane Evid p. 109, table 29
		DCF-based							9.6	
		Historic Utility							10.5	

Vander Weide (cont...)			Stock Returns	Avg Bond Yields	Risk Premium	Expected bond yield		
	Ex-Post Risk Premium	S&P/TSX Utilities: 1956-2011	11.99%	7.33%	4.7%	N/A	N/A	Vander Weide Evid, pp. 32-35, 44; and Exhiibits 8 & 9
		BMO Utilities: 1983-2011	16.01	7.24	8.8%	N/A	N/A	
		Average risk premium of the two samples				6.7%	2.95%	
							10.15 (rounded to 10.2% (incl. 0.5% flotation	

...EQUITY RISK PREMIUM MODELS

Analyst	Model sub-Type	Sample Group and Period	DCF Growth rate	Risk Prem.	Risk Free Rate	Roe est. (%)	References
Vander Weide (cont. from previous page)	Ex-Ante Risk Premium	Natural Gas group selected from S&P nat. gas companies	DCF growth rate and analysis by individual company from I/B/E/S forecast of earnings growth for each month. (Exhibits 10 & 11)	8.0%	2.95%	11.5 (incl flotation)	Vander Weide Evid. pp. 35-38 and App. 3, Exhibits 10, 11 and 24
		Moody's group of 24 Electric utilities.		7.5%	2.95%	11.0 (incl flotation)	
Booth	N/A						
Safir	N/A						

COMPARABLE EARNINGS TESTS

Analyst	Model sub-Type	Sample Group and Period	ROE est. (%)	References
McShane	Book-value based	21 Canadian unregulated companies: 2004-2011 (incl downward adjustments of 125 to 150 bps)	Range: 11.0-12.0 Est: 11.5	McShane Evid, pp. 113-117, 119 and App E.
Vander Weide	N/A		N/A	
Booth	Book-value based	Corporate Canada (Statistics Canada reported earnings): 1987-2011, and TSX composite for the same period	Market ret: 9.3	Booth Evid. p. 93 and App. E, Schedule 2
Safir	Market-value based	Canadian sample: same 21 Canadian Companies as used by McShane: 2004-2011	6.85	Safir Evid. pp. 28-35 and Schedules 5 and 6
	Market-value based	US Sample: 31 US companies in the consumer goods, industrial goods or service sectors using same selection criteria as McShane used for her Canadian sample: 2004-2011.	5.81	
	Weighted average giving Canadian results twice the weight of the US results		6.50	

SUMMARY OF ROE RECOMMENDATIONS

Analyst	Method	Model Sub-Type	'Bare-bones' Cost of Equity"	Financing Flexibility Adjustment	ROE est. (%)	References
McShane	DCF		9.4%	0.50%	9.9	McShane Evid. pp. 6 and 119
	Risk Premium	Risk-Adj Equity Mkt	9.0%	0.50%	9.5	
		DCF-based	9.6%	0.50%	10.1	
		Historic Utility	10.5%	0.50%	11.0	
	Comp. Earning		N/A	N/A	11.5	
VanderWeide	DCF		9.5%	0.5%	10.15	Vander Weide Evid. p. 44 and Exhibit 7
	CAPM	Calculates ROEs (incl. flotation allowance) of 8.27% and 9.52% but gives the CAPM results no weight			N/A	Vander Weide Evid. p. 44 and Exhibits 12 and 13
	Risk Premium	Ex-Post RP	9.65%	0.50%	10.15 (10.2)	Vander Weide Evid. pp. 35, 38 and 44, and Exhibits 8, 9, 10, 11 and 24
		Ex-Ante RP (average of Natural Gas and Elec. Samples	10.75%	0.50%	11.25	
Booth	Discounted Cash Flow	All of Canadian market	9.28% for the market as a whole		N/A	Booth Evid. p. 93-94 and App. D, pp. 9-10
		US market – S&P 500	9.5% - 10.5% for the US market		N/A	
	CAPM	Adjusted for credit spread and Operation Twist	6.95-7.50%	0.50%	7.50	Booth Evid. pp. 93-94
	Comp. Earning	Market Returns	9.3% for Corporate Canada (StatsCan)		N/A	Booth Evid, p. 93-94; App. E, pp. 2-7
Safir	DCF	Canadian Sample	8.99%	0.47%	9.46	Safir Evid, p. 26
		US Sample	8.86%	0.47%	9.33	
	CAPM	Canadian Sample	6.15%	0.32%	6.47	Safir Evid. p. 12
		US Sample	7.68%	0.40%	8.08	Safir Evid. p. 18
		Weighted average	N/A	N/A	7.01	Safir Evid, p. 19
	Comp Earning	Market value based results; wighted avg of Can and US results			6.50	Safir Evid. p. 33

LIST OF ACRONYMS

AAM	Automatic Adjustment Mechanism
AECO	Alberta's gas trading price
AES	Alternative Energy Services
AMPC	Association of Major Power Consumers
AUB	Alberta Utilities Commission
B	Beta
BA	Bankers' Acceptances
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCUC	British Columbia Utilities Commission
BC Utility Customers	Collectively AMPC, BCPSO, CEC
bps	Basis points
CAPM	Capital Asset Pricing Model
CDOR	Canadian Dealer Offered Rate
CEC	Commercial Energy Consumers of B.C.
CEA	Clean Energy Act
Concentric	Concentric Economic Advisers
CPCN	Certificate of Public Convenience and Necessity
DCF	Discounted Cash Flow
ERP	Equity Risk Premium
FRS	Fair Return Standard
FBCU	FortisBC Utilities
FI PUC	Florida Public Service Commission

LIST OF ACRONYMS

GCOC	Generic Cost of Capital
GJ	Gigajoule
ICG	Industrial Customers Group of FortisBC Inc.
LCBF	Long Canada Bond Forecast
NEB	National Energy Board
O&M	Operation and Maintenance
PBR	Performance Based Ratemaking
PNG	Pacific Northern Gas
PRMP	Price Risk Management Plan
OEB	Ontario Energy Board
ROE	Return on Equity
r_m	Expected return on the market
r_f	Risk free rate
$r_m - r_f$	Market risk premium
r_e	Opportunity cost of equity
Régie	Régie de l'Énergie
TES	Thermal Energy Services
Terasen, TGI	Terasen Utilities, Terasen Gas Inc.
UCA	Utilities Commission Act
UPC	Use Per Customer



British Columbia
Utilities Commission

IN THE MATTER OF

FortisBC Energy Inc.

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

DECISION

and Order G-129-16

August 10, 2016

Before:

K. A. Keilty, Commissioner/Panel Chair

D. A. Cote, Commissioner

N. E. MacMurchy, Commissioner

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EXECUTIVE SUMMARY

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

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

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

Contextual issues

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

Dealing with uncertainty

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

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

- Sensitivity of the DCF model to growth rate assumptions.

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

Fair Return Standard

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

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

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

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

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

Automatic Adjustment Mechanism

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

FEI as the benchmark utility

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

1.0 INTRODUCTION

1.1 Overview of the application

On October 2, 2015, FortisBC Energy Inc. (FEI) filed an application for a review of its common equity component and return on equity (ROE) for 2016 (Application) pursuant to the British Columbia Utilities Commission (Commission) decision in the 2012 Generic Cost of Capital (GCOC) Stage 1 proceeding. In the Application, FEI requests approval of a capital structure of 40 percent equity and 60 percent debt and a return on common equity of 9.5 percent for 2016.¹ This compares to FEI's currently allowed ROE of 8.75 percent and common equity component of 38.5 percent.

1.2 Background

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

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

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

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

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

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

¹ Exhibit B-1, p. 1.

² British Columbia Utilities Commission Generic Cost of Capital Stage 1 (2013 GCOC), Decision dated May 10, 2013, Order G-75-13.

³ FortisBC Energy Inc. Annual Review of 2016 Delivery Rates, Order G-193-15 with Reasons for Decision dated December 7, 2015.

1.3 Purpose and scope of the proceeding

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

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

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

1.4 Regulatory process

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

Six parties registered as interveners in this proceeding:

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

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

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

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

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

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

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

1.5 Approach to the decision

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

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

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

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

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

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

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

2.0 APPLICATION OF THE FAIR RETURN STANDARD

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

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

- a) The comparable investment requirement;
- b) The financial integrity requirement; and
- c) The capital attraction requirement.

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

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

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

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

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

⁵ FEI Final Submission, pp. 8–10.

⁶ FEI Final Submission, p. 12.

⁷ AMPC/BCOAPO Final Submission, p. 13.

⁸ 2013 GCOC Decision, p. 100.

⁹ *Utilities Commission Act*, RSBC 1996, Chapter 473, section 59(5).

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

3.0 CONTEXTUAL ISSUES

3.1 Determinations in the 2013 Generic Cost of Capital Decision

3.1.1 Key determinations in the 2013 GCOC Decision

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

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

- a) Weighting of the models – it was determined that the two most compelling frameworks for assessing the cost of equity are the discounted cash flow (DCF) model and the capital asset pricing model (CAPM). These two models were given equal weight when determining the allowed ROE.¹¹
- b) Relevance of US data - it was determined that it was appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the AAM (2006 TGI ROE) Decision and again in the 2009 Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. Return on Equity and Capital Structure (2009 TGI ROE) Decision. However, the Commission did not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities. It was of the view that the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which might exist.¹²
- c) Comparability with other Canadian jurisdictions - the Commission took the view that it is important to consider the methodologies, approaches and regulatory principles related to other jurisdictions’ decision. However, it did not accept that results and values from other jurisdictions could be used for the purposes of determining the ROE and common equity component requirements for utilities in BC.¹³
- d) Relevance of disparity between allowed and actual ROE¹⁴ - as part of assessing the relevance of the disparity between “allowed” and “actual” ROE, the Commission considered the question of whether FEI faced any short-run risks with respect to its ability to annually earn its allowed ROE given its strong track

¹⁰ 2013 GCOC Decision, p. 8.

¹¹ 2013 GCOC Decision, p. 80.

¹² 2013 GCOC Decision, pp. 19–20.

¹³ 2013 GCOC Decision, p. 20.

¹⁴ The Commission approves a ROE that meets the Fair Return Standard. Based on the approved ROE, a revenue requirement is calculated and rates are set and approved by the Commission at levels that are judged to allow the utility the opportunity to earn its approved ROE. The utility may earn more than its approved ROE or less, depending on the efficiency of its operations and on the economic circumstances it encounters. The term “allowed ROE” or “approved ROE” means the ROE found by the Commission that meets the Fair Return Standard. The term “actual ROE” or “realized ROE” refers to the ROE that the utility ends up achieving.

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

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

3.1.2 Relevance to current proceeding

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

3.2 **Changes in economic and global market conditions since 2012**

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

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

Generally, current capital market conditions are not dissimilar to what they were in June 2012. Capital markets continue to recover from the global economic crisis of 2008-2009, but at a slower than expected pace and have shown little change from when FEI last filed its GCOC evidence in 2012. Bond yields have remained low and utility bond spreads have remained somewhat elevated, with no significant movements since June 2012.¹⁷

...Though financial markets have reflected more optimism in valuations, recent financial market volatility indicates that optimism may be waning and uncertainty persists in today's financial markets, as it did in June 2012, as the pace of recovery proves slower than expected and the impact of China's economic slowdown has yet to be fully realized on the global economy. Though it is difficult to predict what will unfold, I would not characterize the global economy as appreciably improved today from where it stood in its recovery in June 2012, and accordingly, I would not expect investors to view current capital market conditions as dissimilar to those in June 2012.¹⁸

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

¹⁵ 2013 GCOC Decision, p. 22.

¹⁶ 2013 GCOC Decision, p. 80.

¹⁷ Exhibit B-1, Appendix B, p. 22.

¹⁸ Exhibit B-1, Appendix B, p. 24.

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

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

FEI describes the current Canadian environment as continuing to be dominated by uncertainty and as “not materially different from 2012 levels.”²⁰

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

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

Intervener submissions

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

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

FEI reply submission

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

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

¹⁹ Exhibit C7-7-2, pp. 2–3.

²⁰ Exhibit B-1, p. 13.

²¹ Exhibit B-1, Appendix B, p. 19.

²² Exhibit B-9, BCUC IR 32.2.

²³ Exhibit C7-7-2, pp. 34–45.

²⁴ CEC Final Submission, p. 10.

²⁵ AMPC/BCOAPO Final Submission p. 37.

²⁶ FEI Final Submission, p. 32.

Panel discussion

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

3.3 Consideration of other jurisdictions

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

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

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

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

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

4.0 CAPITAL STRUCTURE

4.1 Assessing business risks

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

²⁷ FEI Reply Submission, pp. 13–14.

²⁸ Oral Hearing Transcript Volume 3, pp. 581–595; FEI Final Submission p. 77.

²⁹ 2013 GCOC Decision, p. 24.

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

4.1.1 Establishing a framework for assessing risk

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

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

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

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

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

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

³⁰ 2013 GCOC Decision, p. 24.

³¹ Exhibit B-1, Appendix B, p. 61.

³² Exhibit C7-7-2, p. 64.

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

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

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

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

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

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

³³ Exhibit B-1, Appendix B, p. 61.

³⁴ Exhibit C7-7-2, pp. 64–65, 69.

³⁵ AMPC/BCOAPO Final Submission, pp. 18–19.

³⁶ CEC Final Submission, pp. 59–60.

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

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

Commission determination

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

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

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

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

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

³⁷ FEI Final Submission, p. 51.

³⁸ FEI Reply Submission, p. 36.

³⁹ 2013 GCOC Decision, p. 23.

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

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

4.1.3 Impact of amalgamation

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

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

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

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

⁴⁰ British Columbia Utilities Commission Generic Cost of Capital, Stage 2 (2014 GCOC), Decision dated March 25, 2014.

⁴¹ Exhibit B-1, pp. 2-3; Exhibit B-1, Appendix C, p. 1.

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

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

Commission determination

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

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

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

4.2 Assessment of FEI's business risks

4.2.1 Background

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

⁴² Exhibit B-1, Appendix B, pp. 96, 99.

⁴³ Exhibit C7-7-2, p. 2.

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

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

4.2.2 2016 assessment of business risks

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

⁴⁴ Exhibit B-1, p. 17.

⁴⁵ Exhibit B-1, Appendix C, p. 2.

Table 4.1: Change in Business Risk since 2012 and Business Risk Ranking⁴⁶

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

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

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

⁴⁶ Ibid., pp. 3-4.

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

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

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

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

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

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

4.2.3.1 Impact of PBR

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

⁴⁷ Exhibit B-1, pp. 12–14; Exhibit B-1, Appendix C, Tab 2, pp. 4–6.

⁴⁸ Oral Hearing Transcript Volume 2, p. 347; FEI Final Submission, p. 50.

⁴⁹ Exhibit B-1, Appendix B, pp. 74–76.

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

Intervener submissions

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

FEI reply submission

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

Commission determination

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

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

⁵⁰ FEI Final Submission, p. 50.

⁵¹ FEI Reply Submission, pp. 32–33.

⁵² CEC Final Submission, pp. 108–109.

⁵³ FEI Reply Submission, pp. 32–33.

⁵⁴ FEI Application for Approval of 2015 Delivery Rates pursuant to the Multi-Year Performance Based Ratemaking Plan approved for 2014 through 2019 by Order G-138-14, Exhibit B-1, p. 4; FEI Annual Review of 2016 Delivery Rates, Exhibit B-1, p. 4.

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

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

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

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

4.2.3.2 Political risk—recent provincial and municipal activities

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

i) Local governments

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

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

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

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

ii) Provincial government policies and legislation

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

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

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

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

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

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

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

⁵⁶ Exhibit B-1, Appendix C, pp. 64–69; Exhibit B-4, CECIR 44.1.

⁵⁷ Exhibit B-1, Appendix C, Tab 9, pp. 59–63.

⁵⁸ FEI Final Submission, p. 49; Exhibit B-4, CECIR 45.1; Exhibit B-9, BCUCIR 51.1.

⁵⁹ Exhibit B-1, Appendix B, pp. 76–77.

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

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

Intervener submissions

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

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

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

ICG states there is no evidence local government green initiatives have significantly impacted FEI's operations and no material change to throughput can be attributed to municipally owned district energy systems. In addition, ICG asserts the steps taken by the COV are not recent and FEI was aware that both COV and local governments were considering the use of mandatory connections in 2012. ICG also asserts COV was considering the use of an investor owned utility prior to 2012.⁶⁴

⁶⁰ Exhibit C7-7-2, pp. 79–80.

⁶¹ FEI Final Submission, pp. 53–54.

⁶² AMPC/BCOAPO Final Submission, p. 32.

⁶³ CEC Final Submission, pp. 111–113.

⁶⁴ ICG Final Submission, pp. 1–2.

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

FEI reply submission

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

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

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

Commission determination

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

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

⁶⁵ ICG Final Submission, pp. 3–4.

⁶⁶ FEI Reply Submission, p. 22.

⁶⁷ FEI Reply Submission, p. 23.

⁶⁸ FEI Reply Submission, p. 24.

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

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

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

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

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

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

4.2.3.3 Political risk—First Nations

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

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

Intervener submissions

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

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

FEI reply submission

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

Commission determination

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

⁶⁹ Exhibit B-1, Appendix C, Tab 9, p. 72; FEI Final Submission, p. 49.

⁷⁰ Exhibit B-1, Appendix B, p. 63.

⁷¹ AMPC/BCOAPO Final Submission, pp. 32–33.

⁷² CEC Final Submission, p. 113.

⁷³ FEI Reply Submission, p. 26.

4.2.3.4 Energy price risk

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

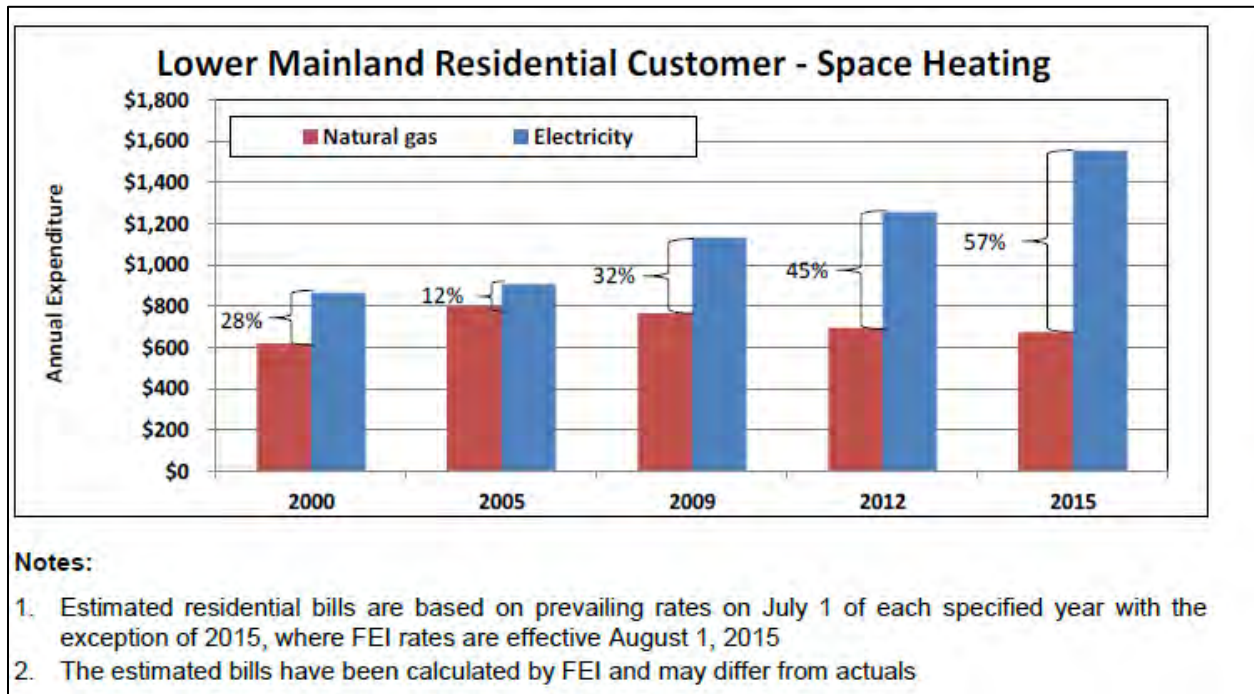
FEI acknowledges commodity prices are reduced from 2012 but have outlined a number of factors to help explain why the impacts of changes in commodity prices do not translate directly to changes in overall risk. In support of its position, FEI makes the following points:

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

Intervener submissions

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

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

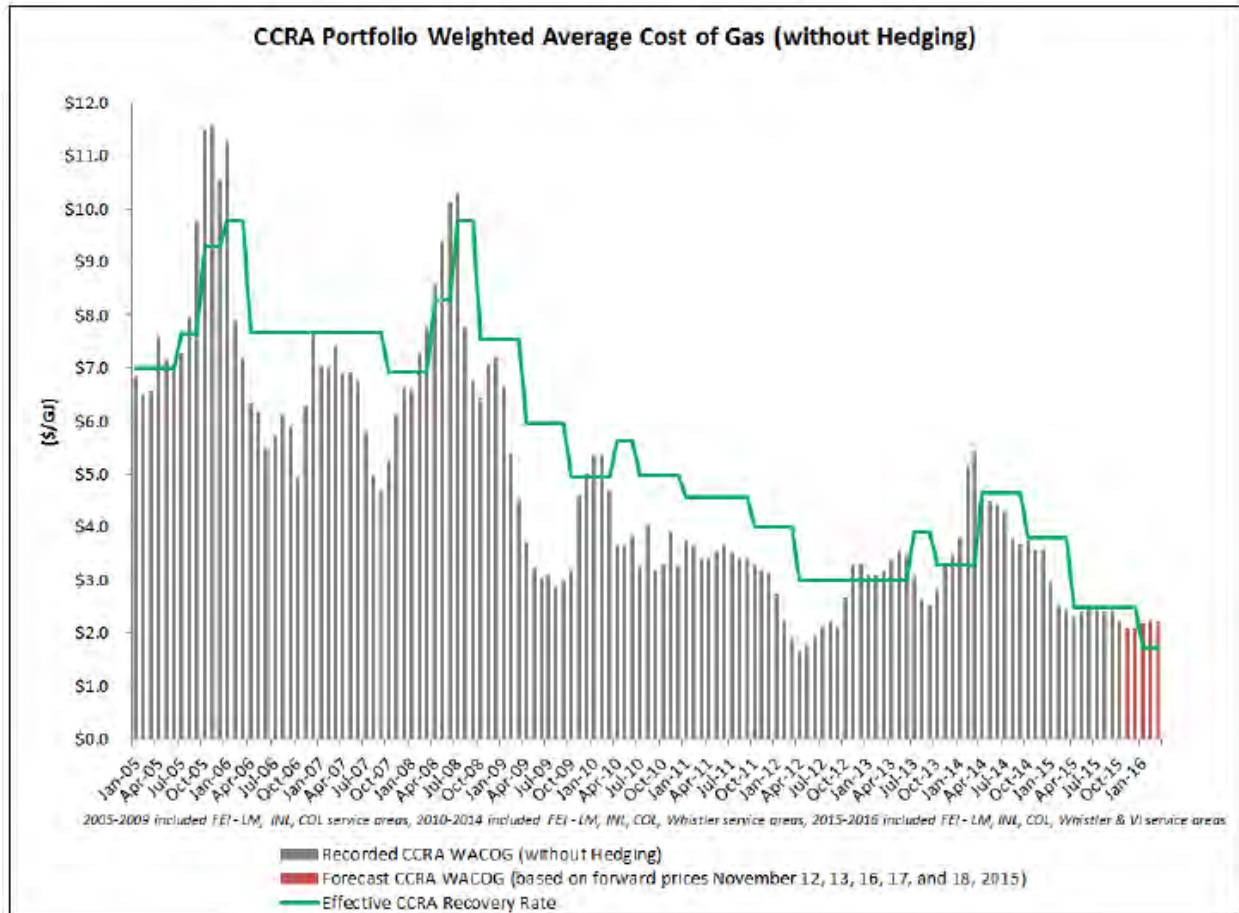
Figure 4.1: Space Heating Price Comparison⁷⁵

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

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

⁷⁵ Exhibit B-7, AMPC IR 2.12.

⁷⁶ AMPC/BCOAPO Final Submission, pp. 21-25.

Figure 4.2: Weighted Average Cost of Gas⁷⁷

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

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

⁷⁷ Exhibit B-9, BCUCIR 27.1.

⁷⁸ AMPC/BCOAPO Final Submission, pp. 21–22.

⁷⁹ CEC Final Submission, pp. 79–88.

FEI reply submission

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

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

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

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

Commission determination

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

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

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

⁸⁰ FEI Reply Submission, pp. 26–27.

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

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

4.2.3.5 Energy supply risk

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

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

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

Intervener submissions

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

⁸¹ Exhibit B-1, Appendix C, p. 46, pp. 51–56; FEI Final Submission, p. 45.

⁸² Exhibit B-1, p. 66.

⁸³ Exhibit C7-7-2, pp. 70–71.

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

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

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

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

FEI reply submission

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

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

FEI rejects CEC's argument that any increase in amalgamated FEI's security of supply is offset by proposed or approved integrity and sustainment projects pointing to their response to BCUC IR 50.2⁸⁷ where it was stated that the projects were needed to operate the gas system in a safe and reliable manner.⁸⁸

⁸⁴ AMPC/BCOAPO Final Submission, pp. 29–30.

⁸⁵ CEC Final Submission, pp. 67–69.

⁸⁶ CEC Final Submission, pp. 71–72.

⁸⁷ Exhibit B-10, BCUC IR 50.2.

⁸⁸ FEI Reply Submission, pp. 33–35.

Commission determination

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

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

4.2.4 Other risk areas

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

Operating risk

Operating risk covers any physical risks to the utility system arising from technical and operational factors which includes items like asset concentration, technologies employed to service, geography in the service area and weather. FEI states that since 2012, there has been no change to the level of operating risk of facilities in the mainland service area. FEI also states the amalgamation of FEI with FEVI and FEW has posed no additional operational risk. FEI has focused its assessment on three areas; infrastructure integrity, third party risks and unexpected events. FEI has assessed its infrastructure integrity and although two-thirds of the current assets will need to be replaced over the next 40 years, acknowledges this was understood in 2012 and the risk remains similar for the amalgamated utility. The incidence of third party damage has been decreasing since 2006 and FEI notes this trend was understood in 2012 and has assessed the risk to the amalgamated utility to be similar to that faced by FEI in 2012. The incidence of natural events is one of the higher operating risks to FEI but remain materially unchanged from what existed in 2012.⁸⁹

Neither AMPC/BCOAPO nor CEC take issue with FEI's assessment of its operational risk and both agreed there was no change since last reviewed in 2012.⁹⁰ ICG provided no specific submissions with respect to operating risk.

⁸⁹ Exhibit B-1, Appendix C, pp. 57–58.

⁹⁰ AMPC/BCOAPO Final Submission, p. 33; CEC Final Submission, p. 66.

Market shift risk

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

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

Economic conditions

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

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

Commission determination

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

4.3 Other items impacting capital structure

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

⁹¹ Exhibit B-1, Appendix C, pp. 39–50.

⁹² AMPC/BCOAPO Final Submission, p. 25; CEC Final Submission, p. 96; ICG Final Submission, p. 3.

⁹³ Exhibit B-1, Appendix C, p. 15.

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

4.3.1 Credit ratings and access to capital

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

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

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

Table 4.2: FEI's Credit Metrics from 2011 to 2014⁹⁶

	FEI's Score	A3 - Rating Threshold ⁹⁴	2011	2012	2013	2014
CFO pre-WC + Interest / Interest	Ba	4.5x	2.3x	2.5x	2.7x	2.8x
CFO pre-WC / Debt	Baa	19.0%	11.2%	14.5%	15.1%	14.4%
CFO pre-WC - Dividends / Debt	Baa	15.0%	6.6%	9.6%	8.0%	10.3%
Debt / Capitalization ⁹⁵	A	50.0%	47.4%	44.0%	43.6%	45.2%

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

FEI stated that it has not been rated below A3 since 2011 and in 2013, Moody's changed FEI's credit outlook to negative due to the reduction in ROE and common equity ratio in the 2013 GCOC Decision. FEI also indicated that its Moody's rating was eventually amended back to stable in June 2014.⁹⁸

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

⁹⁴ FEI Final Submission, p. 56.

⁹⁵ Exhibit B-1, Application, Appendix A, Moody's Investor Services, Credit Opinion: FEI (Moody's Credit Opinion), dated July 20, 2015.

⁹⁶ Exhibit B-1, p. 25.

⁹⁷ Exhibit B-1, p. 25.

⁹⁸ Exhibit B-9, BCUCIR 8.1.

⁹⁹ Exhibit B-1, pp. 24-25.

¹⁰⁰ Exhibit B-9, BCUCIR 8.3.

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

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

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

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

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

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

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

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

¹⁰¹ Exhibit B-9, BCUCIR 9.1.

¹⁰² Exhibit B-1, Application, Appendix A, Moody's Credit Opinion, p. 3; Exhibit B-9, BCUCIR 8.3.

¹⁰³ Exhibit B-1, Appendix B, p. 97.

¹⁰⁴ Exhibit B-1, Appendix A, Moody's Credit Opinion, p. 3, the report states that Moody's does not expect the rating to go down.

¹⁰⁵ Exhibit B-1, Appendix A, Moody's Credit Opinion, p. 3.

¹⁰⁶ Exhibit B-1, Appendix B, p. 97.

¹⁰⁷ Exhibit B-1, Appendix B, pp. 97-98.

¹⁰⁸ Exhibit B-1, Appendix A, Moody's Credit Opinion, p. 3.

¹⁰⁹ Exhibit C7-7-2, p. 35.

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

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

FEI submits:

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

Intervener submissions

AMPC/BCOAPO make the following points in their submission:

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

¹¹⁰ Exhibit C7-7-2, p. 81.

¹¹¹ Exhibit C7-7-2, p. 82.

¹¹² Exhibit B-16, p. 9.

¹¹³ FEI Final Submission, p. 4.

¹¹⁴ FEI Final Submission, pp. 56–58.

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

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

FEI reply submission

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

Commission determination

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

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

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

¹¹⁵ AMPC/BCOAPO Final Submission, pp. 65–67.

¹¹⁶ CEC Final Submission, pp. 51–53.

¹¹⁷ FEI Reply Submission, pp. 39–40.

¹¹⁸ Exhibit B-1, Appendix A, Moody’s Credit Opinion, p. 3.

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

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

4.3.2 Trust indenture issuance test

With respect to its Trust Indenture, FEI states:

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

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

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

¹¹⁹ Exhibit B-1, p. 27.

¹²⁰ Exhibit B-1, pp. 27–28.

Table 4.3: Scenario Analysis of ROE and Equity on Issuance Capacity under the Trust Indenture¹²¹

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

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

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

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

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

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

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

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

Table 4.4: FEI's Total Capital Expenditure and Financing 2016-2018¹²⁴

	2016	2017	2018
Approved Major Capital Projects	130,000	160,000	205,000
Potential Growth Projects ³	-	525,000	525,000
Expected Total Capital Expenditures²	130,000	685,000	730,000
Debt Financing ¹	80,000	420,000	450,000
Equity Financing	50,000	265,000	280,000

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

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

3 - Relates to Tilbury 1B expansion and Woodfibre

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

¹²¹ Exhibit B-1, p. 30.

¹²² Exhibit B-1, p. 30.

¹²³ Exhibit B-9, BCUCIR 11.1.

¹²⁴ Exhibit B-9, BCUCIR 11.3.

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

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

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

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

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

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

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

Dr. Booth's evidence includes the Royal Bank of Canada's (RBC) forecast for the 2017 30-year long Canada bond yield of 3.65 percent¹²⁹ and notes FEI recently issued bonds at an approximate 1.35 percent over equivalent maturity long Canada bonds.¹³⁰ Further, Dr. Booth does not expect the Canada bond yield to exceed 3.8 percent over the next three years.¹³¹

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

¹²⁵ Exhibit B-1, Appendix B, p. 41.

¹²⁶ Exhibit B-1, Appendix B, pp. 19–21.

¹²⁷ Exhibit C7-7-2, p. 2.

¹²⁸ Exhibit C7-7-2, p. 85.

¹²⁹ Exhibit C7-7-2, p. 23.

¹³⁰ Exhibit C7-7-2, p. 1.

¹³¹ Exhibit C7-7-2, p. 2.

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

FEI submits:

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

FEI reply submission

FEI submits that AMPC/BCOAP0 cannot rely on Dr. Booth's evidence on the Trust Indenture and since Dr. Booth did not have a proper understanding of the Trust Indenture, he would not have been able to assess his recommended ROE and common equity ratio against the capital attraction element of the Fair Return Standard. FEI also refers to its rebuttal evidence highlighting how its debt issuance capacity may be significantly constrained in a period of higher debt capital requirements if Dr. Booth's recommended ROE and deemed equity were to be adopted.¹³⁵

Commission determination

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

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

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

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

¹³² Exhibit B-16, p. 11.

¹³³ FEI Final Submission, p. 62.

¹³⁴ FEI Final Submission, p. 63.

¹³⁵ FEI Reply Submission, p. 45.

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

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

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

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

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

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

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

Table 4.6: Canadian Peer Group Comparative Risk Analysis and Authorized Equity Ratio¹³⁶

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

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

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

In his rebuttal evidence, Mr. Coyne states he agrees with Dr. Booth that Gaz Métro is slightly riskier than FEI. Mr. Coyne considers Gaz Métro to be FEI's closest comparator and notes it has the same common equity ratio as FEI of 38.5 percent as well as an allowed 7.5 percent deemed preferred equity at a return of 5.95 percent. In Mr. Coyne's opinion, this is equivalent to roughly 43.5 percent equity at Gaz Métro's current authorized return of 8.90 percent¹³⁹ which puts Gaz Métro's allowed equity component above that being requested by FEI in this proceeding. Mr. Coyne considers this appropriate given Gaz Métro's relative risk to FEI.

¹³⁶ Exhibit B-1, Appendix B, p. 101.

¹³⁷ Exhibit B-1, Appendix B, p. 102.

¹³⁸ Exhibit C7-7-2, p. 78.

¹³⁹ Exhibit B-16, Prepared Rebuttal Testimony of Mr. Coyne, p. 39, Mr. Coyne's calculation supporting the equivalent equity ratio of 43.5% is calculated as follows: $((5.95\% \times 7.5\%) + (38.5\% \times 8.90\%)) / 8.9\%$.

With respect to its main Canadian comparators, FEI submits:

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

Intervener submissions

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

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

FEI reply submission

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

Panel discussion

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

¹⁴⁰ FEI Final Submission, p. 4.

¹⁴¹ FEI Final Submission, p. 60.

¹⁴² AMPC/BCOAPO Final Submission, p. 10.

¹⁴³ AMPC/BCOAPO Final Submission, pp. 63–64.

¹⁴⁴ CEC Final Submission, p. 48.

¹⁴⁵ FEI Reply Submission, p. 43.

¹⁴⁶ Oral Hearing Transcript Volume 3, p. 372.

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

4.3.3.1 Introducing preferred shares to FEI's capital structure

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

Intervener submissions

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

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

FEI reply submission

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

Commission determination

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

¹⁴⁷ Exhibit C7-7-2, p. 86.

¹⁴⁸ AMPC/BCOAPO Final Submission, pp. 63–64.

¹⁴⁹ AMPC/BCOAPO Final Submission, pp. 66–67.

¹⁵⁰ AMPC/BCOAPO Final Submission, p. 67.

¹⁵¹ FEI Reply Submission, p. 45.

4.4 Appropriate capital structure

Commission determination

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

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

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

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

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

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

5.0 RETURN ON EQUITY

5.1 Overview of issues

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

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

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

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

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

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

- i) Should the decision be informed by use of multiple financial models and other indicators of investor expectations?
- ii) In the development of the models, is the selection of the proxy group and the weight placed on US data appropriate?
- iii) With respect to both the CAPM and DCF estimates, are the model inputs used by the experts reasonable and how much weight should be given to each of these models and the resulting estimates?
- iv) In applying the Panel's judgment to the totality of information, what is a fair return on equity for FEI?

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

¹⁵³ 2013 GCOC Decision, p. 56.

5.2 Key differences in views related to ROE

5.2.1 Use of multiple financial models

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

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

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

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

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

Final submissions

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

¹⁵⁴ Exhibit B-1, Appendix B, pp. 34–37.

¹⁵⁵ Exhibit B-1, Appendix B, pp. 104–106.

¹⁵⁶ Oral Hearing Transcript Volume 1, p. 20; Exhibit B-1, Appendix B, pp. 104–106.

¹⁵⁷ Oral Hearing Transcript Volume 1, p. 22.

¹⁵⁸ Oral Hearing Transcript Volume 3, p. 503.

¹⁵⁹ Exhibit C7-7-2, p. 8.

¹⁶⁰ Exhibit C7-7-2, p. 41.

¹⁶¹ Exhibit C7-7-2, p. 50.

¹⁶² Exhibit C7-7-2, p. 56.

¹⁶³ Exhibit C7-7-2, p. 40.

¹⁶⁴ Exhibit C7-7-2, pp. 56–57.

¹⁶⁵ Oral Hearing Transcript Volume 3, p. 659.

¹⁶⁶ FEI Final Submission, p. 65.

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

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

Panel discussion

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

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

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

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

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

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

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

¹⁶⁷ AMPC/BCOAPO Final Submission, p. 38.

¹⁶⁸ CEC Final Submission, p. 13.

¹⁶⁹ Oral Hearing Transcript Volume 3, pp. 581–595; FEI Final Submission, p. 77.

5.2.2.1 Selection and use of US proxy companies

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

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

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

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

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

¹⁷⁰ FEI Final Submission, p. 77.

¹⁷¹ Exhibit B-1, Appendix B, Evidence of Mr. Coyne, p. 87.

¹⁷² Oral Hearing Transcript Volume 3, pp. 586–587.

¹⁷³ Exhibit B-8, AMPC IR 4.2.

¹⁷⁴ Exhibit B-8, AMPC IR 4.5.

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

US Proxy Company	Differences in Regulatory Practice Compared to FEI
Atmos Energy Corporation*	(Comments are related to Texas where 70% of Atmos' regulatory assets are located) - Some capital additions may be brought into rates without prior regulatory approval¹⁷⁵ - Elected regulators who receive political donations from Atmos¹⁷⁶ - Test year determined on a historical basis¹⁷⁷
South Jersey Resources Corp.*	Partially forecast test year¹⁷⁸
Northwest Natural Gas*	Oregon - Partially to fully forecast test year - No interim rates Washington - Historical test period - Interim rates allowed under emergency circumstances¹⁷⁹
Piedmont Natural Gas*	- Historical test period in North and South Carolina - Formula rate plan (annual rate mechanism) in Tennessee and North Carolina¹⁸⁰
New Jersey Industries, Inc.	- Partially forecast test year - Interim rates allowed on an emergency basis - Company retains 100% of the first \$7.8 million of margins associated with off-system sales, interruptible sales, and interruptible transportation activities. Margins beyond this are allocated 85% to ratepayers and 15% to the company¹⁸¹
Southwest Gas Corporation*	- Historical test year - Interim rates not allowed in Nevada, allowed on an emergency basis in California¹⁸²

¹⁷⁵ Oral Hearing Transcript Volume 2, pp. 408–410.¹⁷⁶ Oral Hearing Transcript Volume 2, pp. 413–414.¹⁷⁷ Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-59.¹⁷⁸ Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-64.¹⁷⁹ Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-68.¹⁸⁰ Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-72.¹⁸¹ Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-76.¹⁸² Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, p. A-81.

WGL Holdings Inc.*	• Historical test year with some items forecast in Washington, DC • Historical test year in Virginia and Maryland • Interim rates are rarely requested in Maryland and generally not requested in Washington, DC¹⁸³

* Also used as a proxy company by Dr. Booth

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

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

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

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

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

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

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

¹⁸³ Exhibit B-1, Appendix B, Evidence of Mr. James Coyne, Appendix A, pp. A-86-A-87.

¹⁸⁴ Oral Hearing Transcript Volume 2, p. 413.

¹⁸⁵ Oral Hearing Transcript Volume 2, p. 415.

¹⁸⁶ FEI Final Submission, p. 78.

¹⁸⁷ FEI Final Submission, p. 78.

¹⁸⁸ Exhibit C7-7-2, Appendix D, p. 14.

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

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

5.2.2.2 Canadian proxy companies

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

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

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

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

¹⁸⁹ Exhibit C7-7-2, Appendix D, pp. 14–16.

¹⁹⁰ Exhibit C7-7-2, Appendix D, p. 14.

¹⁹¹ Exhibit C7-7-2, Appendix C, p. 9.

¹⁹² Oral Hearing Transcript Volume 3, pp. 662–663.

¹⁹³ CEC Final Submission, pp. 15–16.

¹⁹⁴ Exhibit B-1, Appendix B, Evidence of Mr. Coyne, Appendix A, pp. A-16 to A-51.

¹⁹⁵ Exhibit B-1, Appendix B, p. 33.

¹⁹⁶ Exhibit B-1, Appendix B, p. 29.

¹⁹⁷ Exhibit C7-7-2, Evidence of Dr. Booth, Appendix C, p. 8.

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

Commission determination

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

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

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

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

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

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

¹⁹⁸ Exhibit B-1, Appendix B, p. 31.

¹⁹⁹ Exhibit B-1, Appendix B, p. 29.

²⁰⁰ Exhibit B-1, Appendix B, Appendix A, pp. A-57 to A-87.

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

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

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

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

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

5.2.3 CAPM/risk premium model

5.2.3.1 Overview of the CAPM estimates and model

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

- i) Risk free rate of return;

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

- ii) Return for the market as a whole or the market risk premium (MRP); and
- iii) Beta of an individual security or the measure of covariance between the return on a specific security and the market.²⁰²

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

Issues with the CAPM model

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

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

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

- i) The approach is sensitive: the method of calculating the risk premium, the selection of a security for the risk free rate, the use of forward-looking or historical data and the determination of whether adjustments to Beta are appropriate;
- ii) The model assumes that: (1) all investors will behave in an efficient manner and manage their portfolios to diversify risk and will make investment decisions considering the impact of a security on the portfolio; and (2) the market is well functioning; and
- iii) The problems of the CAPM are exacerbated in the current market environment where risk free rates remain near all-time lows²⁰⁵ and consistent with the views of Dr. Booth, result in the need to modify the traditional CAPM assumptions to achieve a reasonable ROE recommendation.²⁰⁶

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

²⁰² Exhibit B-1, Appendix B, p. 40.

²⁰³ Exhibit C7-7-2, p. 36.

²⁰⁴ Exhibit A2-3, p. 4.

²⁰⁵ Exhibit B-1, Appendix B, pp. 35–36.

²⁰⁶ Oral Hearing Transcript Volume 1, p. 21.

²⁰⁷ Exhibit C7-7-2, p. 36.

²⁰⁸ Exhibit C7-7-2, pp. 41–42.

²⁰⁹ Exhibit C7-7-2, p. 42.

Comparison of CAPM estimates

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

Table 5.2: Comparison of CAPM Estimates

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

²¹⁰ Exhibit B-1, Appendix B, Exhibit JMC-5.

²¹¹ Exhibit B-1, Appendix B, Table 5, p. 41. $3.68 = [(2.1+3.2+3.6)/3]+0.71$.

²¹² Exhibit B-1, Appendix B, Table 7, p. 49. The Canadian MRP is a range of 5.6 to 9.8 and the US MRP is a range of 7.0 to 8.1 based on historical and forward-looking estimates and 7.6 is the average of the Canadian and US estimates.

²¹³ Exhibit B-1, Appendix B, Table 6, p. 44.

²¹⁴ Exhibit B-1, Appendix B, Evidence of Mr. Coyne, pp. 40–41. $3.68 = [(2.1+3.2+3.6)/3]+0.71$; although Mr. Coyne presented 4.29 percent as the US risk-free rate, his US proxy group CAPM calculations in Exhibit JMC-5 Schedules 1 and 2 actually used the 3.68 percent Canadian risk-free rate to arrive at an estimate of 10.08 percent.

²¹⁵ Exhibit B-1, Appendix B, Table 7, p. 49. The Canadian MRP is a range of 5.6 to 9.8 and the US MRP is a range of 7.0 to 8.1 based on historical and forward looking estimates and 7.6 is the average of the Canadian and US estimates.

²¹⁶ Exhibit B-1, Appendix B, Table 6, p. 44.

²¹⁷ Exhibit B-1, Appendix B, Table 21, p. 104.

²¹⁸ Exhibit C7-7-2, p. 23, the average of the March and December Consensus Economics forecasts which is a proxy for the average for the year as a whole and consistent with the application to an average forward test year rate base, is 2.75%.

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

- i) The adjustments needed to the risk free rate to compensate for the abnormal conditions in the bond markets resulting from the impact of global bond buying programs.
- ii) The use of income or total returns in the derivation of the historical MRP.
- iii) The methodology to calculate and necessity of using a forward looking MRP to reflect the current expectation of investors.
- iv) Testing reasonableness of MRP estimates.
- v) The appropriate adjustment to beta.

5.2.3.2 Estimate of risk free rate and adjustment for abnormal conditions

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

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

Table 5.3: Mr. Coyne's Calculation of Risk Free Rate Adjusted for Abnormal Conditions²²⁷

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

Mr. Coyne selected the 2016 to 2018 period to match the period he expects FEI's rates are most likely to be in effect²²⁸ and explained his use of a three-year forecast in the current abnormal market conditions:

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

²¹⁹ Exhibit C7-7-2, p. 39.

²²⁰ Exhibit C7-7-2, p. 41.

²²¹ Exhibit C7-7-2, p. 41, $5.50 = (5.0 \times .45) + 2.75 = 2.25 + 2.75 = 5.0 + 0.5 \text{ flotation} = 5.50$; and $6.55 = (6 \times .55) + 2.75 + 0.5 \text{ flotation} = 6.55$.

²²² Exhibit C7-7-2, p. 44.

²²³ Exhibit C7-7-2, p. 50, the Risk Premium Estimate is the CCAPM adjusted for an estimate of Operation Twist and is a range of 7.25% to 8.30%.

²²⁴ Exhibit C7-7-2, p. 50.

²²⁵ Exhibit C7-7-2, p. 50.

²²⁶ Exhibit B-1, Appendix B, pp. 40-41.

²²⁷ Exhibit B-1, Appendix B, p. 41.

²²⁸ Exhibit B-1, Appendix A, p. 40.

what looks like a return to something that's in equilibrium. Just as this commission did in 2012, it made a determination that there should be a floor of the risk-free rate, on a judgment that needed to be something that at least looked like an equilibrium risk-free rate, in order for it to be sensible for a cost of equity determination.

So that's the very same logic here. The difference is that I am not trying to estimate it myself. I am looking at this consensus forecast and I am looking at the shape of it. Because it flattens out once you get to 2018. So it tells me that in that range it gets you to something that looks like equilibrium or more normalized level of risk free bond yield. So, that's the logic. I'm not trying to pinpoint one year, or three years for that matter.²²⁹

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

In the 2012 GCOC proceeding, Dr. Booth placed the impact of Operation Twist on the Canadian bond market at approximately 80 bps from August 2011 through to May 2013.²³² In the 2013 GCOC Decision, the Commission accepted Dr. Booth's adjustment.²³³

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

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

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

²²⁹ Oral Hearing Transcript Volume 1, pp. 186–187.

²³⁰ Exhibit C7-7-2, p. 23.

²³¹ Exhibit C7-7-2, p. 48.

²³² Exhibit C7-7-2, p. 48.

²³³ 2013 GCOC Decision, p. 60.

²³⁴ Exhibit C7-7-2, p. 49; Exhibit C7-9, BCUC IR 12.1.

²³⁵ Exhibit C7-7-2, pp. 48–49.

²³⁶ Oral Hearing Transcript Volume 3, p. 538.

²³⁷ Oral Hearing Transcript Volume 3, p. 542.

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

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

Intervener submissions

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

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

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

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

FEI reply submission

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

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

²³⁸ FEI Final Submission, p. 92.

²³⁹ AMPC/BCOAPO Final Submission, pp. 45, 53.

²⁴⁰ CEC Final Submission, p. 23.

²⁴¹ CEC Final Submission, p. 23.

²⁴² CEC Final Submission, p. 24.

²⁴³ CEC Final Submission, p. 40.

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

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

Commission determination

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

- Rely on Consensus Economics forecasts of the 30-year Government of Canada bond yield as the risk-free rate;
- Are very close in their estimates of 10-year and 30-year yield spreads; and
- Agree on the need to add an additional adjustment to the CAPM to compensate for abnormal conditions in the bond markets resulting from the impact of global bond buying programs.

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

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

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

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

²⁴⁴ FEI Reply Submission, pp. 52–55.

²⁴⁵ FEI Reply Submission, pp. 17–18.

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

5.2.3.3 Market risk premium (MRP)

Estimate of market risk premium

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

Table 5.4: Market Risk Premium Values²⁴⁶

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

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

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

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

Mr. Coyne determines his ex-post MRP based on the arithmetic average of historical risk premia: for Canada using Morningstar Direct from 1919 through 2011 and Duff and Phelps thereafter and for the US using Duff & Phelps from 1926 onwards.²⁴⁹ Mr. Coyne uses estimates of the total return on equities over the income return on bonds²⁵⁰ consistent with the Ibbotson® SBBI® Valuation Yearbook since in his view, this represents the truly risk free rate.²⁵¹

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

²⁴⁶ Exhibit B-1, Appendix B, p. 49.

²⁴⁷ Exhibit B-1, Appendix B., p. 49.

²⁴⁸ Exhibit C7-7-2, pp. 39–40.

²⁴⁹ Exhibit B-1, Appendix B, pp. 45–46.

²⁵⁰ Oral Hearing Transcript Volume 1, p. 195.

²⁵¹ Oral Hearing Transcript Volume 1, p. 198.

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

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

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

Intervener submissions

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

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

FEI reply submission

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

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

5.2.3.3.2 Use of a forward-looking MRP estimate

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

²⁵² Exhibit C7-9, BCUCIR 11.1.

²⁵³ Exhibit C7-8, FEI IR 11.3.

²⁵⁴ Exhibit C7-8, FEI IR 10.3.

²⁵⁵ AMPC/BCOAPO Final Submission, p. 8.

²⁵⁶ CEC Final Submission, p. 31.

²⁵⁷ FEI Reply Submission, pp. 56–57.

²⁵⁸ Exhibit B-1, Appendix B, p. 47.

²⁵⁹ Exhibit B-1, Appendix B, p. 47.

In his ex-ante MRP, Mr. Coyne uses a constant growth DCF methodology to determine the implied expected market return using the S&P/TSX Composite Index for Canada and for the S&P 500 index for the US²⁶⁰ and he subtracts his forecast risk free rate from the derived expected market returns to arrive at his forward-looking equity risk premia results of 9.78 percent and 8.08 percent, respectively, for Canada and the US²⁶¹ In his view, these results “suggest that a pure historical estimate is too low in today’s low interest rate environment.”²⁶²

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

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

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

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

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

Intervener submissions

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

²⁶⁰ Exhibit B-1, Appendix B, pp. 45–46.

²⁶¹ FEI Final Submission, p. 93.

²⁶² Exhibit B-1, Appendix B, p. 48.

²⁶³ Exhibit B-4, Appendix B, Exhibit JMC-4, Schedule 1 and 2.

²⁶⁴ Oral Hearing Transcript Volume 3, pp. 486–488.

²⁶⁵ Exhibit C7-9, BCUCIR 11.1.

²⁶⁶ FEI Final Submission, p. 93.

²⁶⁷ AMPC/BCOAPO Final Submission, pp. 52–53.

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

FEI reply submission

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

5.2.3.3.3 Methods to test the reasonableness of MRP estimates

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

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

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

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

Intervener submissions

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

²⁶⁸ CEC Final Submission, p. 30.

²⁶⁹ FEI Reply Submission, p. 58.

²⁷⁰ Exhibit B-1, Appendix B, p. 49.

²⁷¹ Exhibit B-1, Appendix B, p. 50.

²⁷² Exhibit B-12, CEC IR 46.1.

²⁷³ Exhibit B-12, CEC IR 46.8.1.

²⁷⁴ Exhibit C7-7-2, pp. 39-40.

²⁷⁵ FEI Final Submission, p. 94.

markets. AMPC/BCOAPO also submit that Dr. Booth's results are comparable to independent and credible forecasts including TD Economics, AON Hewitt and Mercer²⁷⁶ and the estimates used by Mr. Coyne calculating his MRP exceed the expectations of each of the independent forecasters for the market as a whole.²⁷⁷

CEC endorses Dr. Booth's conclusions on the MRP²⁷⁸ and raises additional issues with Mr. Coyne's evidence as follows:

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

FEI reply submission

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

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

Commission determination

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

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

²⁷⁶ AMPC/BCOAPO Final Submission, pp. 50–51.

²⁷⁷ AMPC/BCOAPO Final Submission, p. 52.

²⁷⁸ CEC Final Submission, p. 38.

²⁷⁹ CEC Final Submission, p. 32.

²⁸⁰ CEC Final Submission, p. 32.

²⁸¹ CEC Final Submission, p. 34.

²⁸² FEI Reply Submission, pp. 58–60.

²⁸³ FEI Reply Submission, p. 60.

a) Use of income or total returns

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

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

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

b) Use of forward-looking MRP estimates

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

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

While Dr. Booth estimates the MRP of common equities over long-term Canada bonds at 5.0-6.0 percent using historical Canadian capital market history, the Panel takes note of Dr. Booth's constant growth DCF estimates for the market as a whole as set out in Table 5.5, where he estimates an average of 8.75 percent for the Canadian market as a whole and 9.6 percent for the US market as a whole based upon his estimates of sustainable growth

rates. Dr. Booth's sustainable growth rates average 5.25 percent and 6.91 percent for Canada and US markets, respectively. In comparison, Mr. Coyne's constant growth DCF estimates for the market as a whole using a constant growth model are 10.02 percent for the Canadian market and 9.66 percent for the US market. The Panel considers a reasonable forward-looking growth rate to be somewhere between the estimates of the two experts. **Therefore, with the application of judgement, the Panel accepts 6.5 to 7.5 percent as a reasonable range of estimates for a forward-looking MRP.**

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

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

c) Methods used to test whether MRP estimates were reasonable

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

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

5.2.3.4 Beta and beta adjustments

Beta estimates

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

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

- (1) Value Line for the US gas distribution proxy group which reports historical beta based on five years of weekly stock returns and uses the New York Stock Exchange as the market index.
- (2) Bloomberg for the Canadian proxy group which Mr. Coyne set to five years of weekly returns on the S&P 500 or S&P/TSX Composite Index.

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

Based on his analysis, Dr. Booth judges the relative risk of Canadian regulated utilities to be 45 to 55 percent of the market as a whole.²⁸⁵ Dr. Booth uses five years of monthly data and estimates each beta using the standard formula covariance (Y, X) divided by Population variance (X).²⁸⁶ He states that the recent history of the beta coefficients of Canadian utilities is in the approximate range of 0.30 to 0.45 and attributes the higher end of this range to the post-financial crisis and the internet bubble.²⁸⁷ In Dr. Booth's view, as interest rates increase back to normal levels, he expects their betas to revert back to their long-run average of 0.45 to 0.55.²⁸⁸

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

5.2.3.4.1 The appropriate adjustment to beta

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

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

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

²⁸⁴ Exhibit B-1, Appendix B, p. 42.

²⁸⁵ Exhibit C7-7-2, p. 40.

²⁸⁶ Exhibit C7-7-2, Appendix C, p. 6, Schedule 2.

²⁸⁷ Exhibit C7-7-2, p. 40.

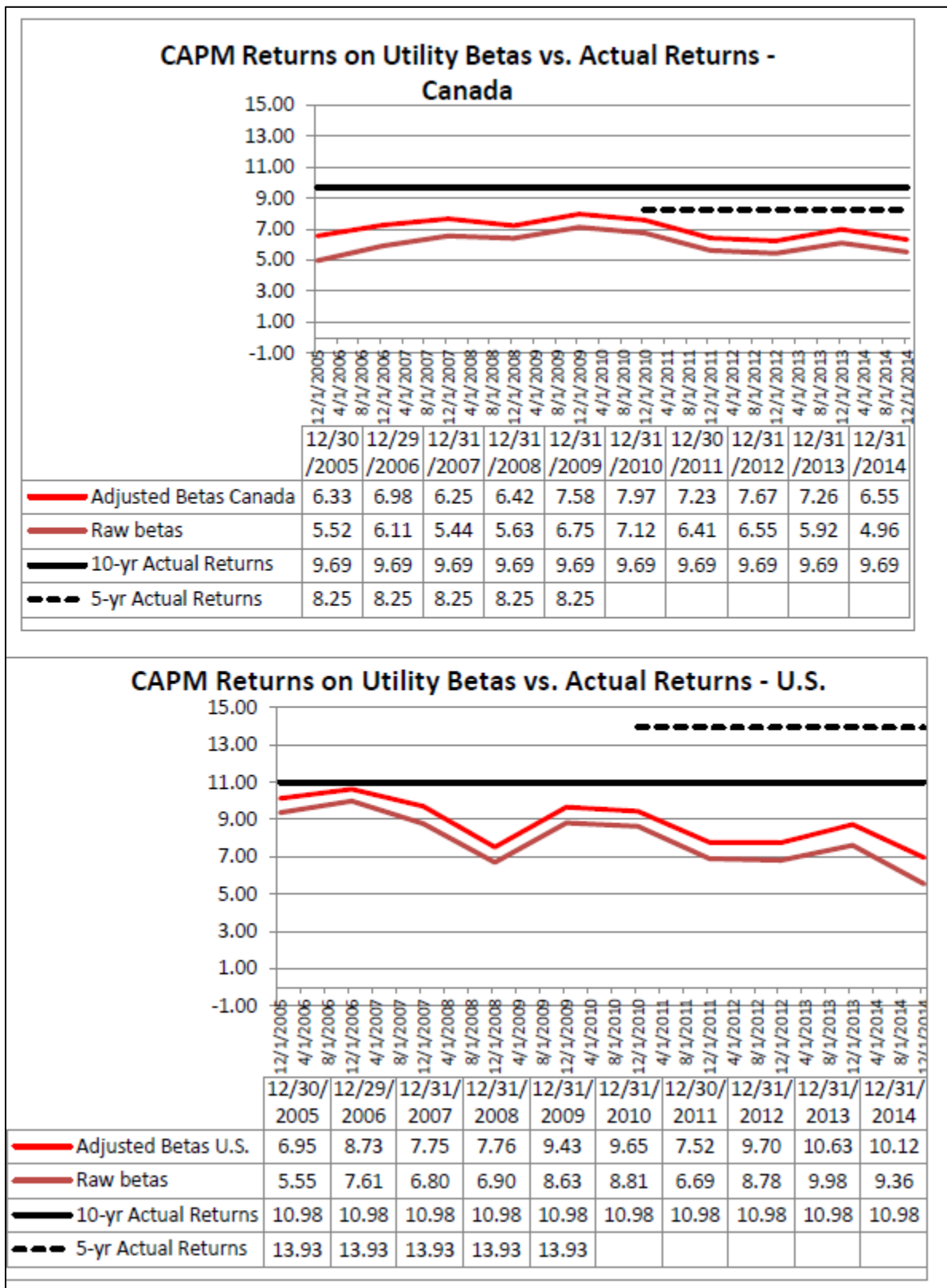
²⁸⁸ Exhibit C7-7-2, Appendix C, p. 6.

²⁸⁹ Exhibit C7-7-2, Appendix C, p. 8.

²⁹⁰ Exhibit C7-7-2, Appendix C, p. 10.

²⁹¹ Exhibit C7-7-2, Appendix C, p. 6.

²⁹² Exhibit B-1, Appendix B, pp. 42-43.

Figure 5.1: Comparison of CAPM Returns on Utility Betas vs. Actual Returns²⁹³²⁹³ Exhibit B-8, AMPC-Concentric IR 5.4.

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

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

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

With respect to adjusted betas, in Dr. Booth’s view, utility witnesses frequently adjust toward the overall market average of 1.0 which is the level recommended by Blume for the “whole universe of stocks.” He states that low beta estimates for utilities “do not mean they are under-estimates, since utility betas are perennially low due to their low risk”²⁹⁹ and that there is no evidence of these estimates going towards 1.0.³⁰⁰ Dr. Booth also discusses the work of Gombola and Kahl who he states demonstrate that utility betas are better mechanically adjusted to their grand mean of around 0.50. Dr. Booth finds that such an adjustment makes very little difference to his estimates. Recognizing that betas need to be adjusted, Dr. Booth prefers to “use judgement constrained by the actual historic evidence.”³⁰¹

With respect to the use of Merrill Lynch and Value Line to provide adjusted betas, Dr. Booth notes these are US data providers and companies in Canada such as the Financial Post, RBC and the Globe & Mail do not adjust betas and this approach enables the user to apply judgment. He stated he has no issue with adjusting betas but has a problem with adjusting them towards 1.0.³⁰²

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

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

²⁹⁴ Exhibit B-8, AMPC-Concentric IR 5.4.

²⁹⁵ Exhibit A2-3, Brattle Group Report, May 31, 2012, pp. 15–16.

²⁹⁶ Oral Hearing Transcript Volume 2, pp. 228–230.

²⁹⁷ Exhibit B-16, Rebuttal Evidence of Mr. Coyne, p. 28.

²⁹⁸ Exhibit B-16, Rebuttal Evidence of Mr. Coyne, p. 28.

²⁹⁹ Exhibit C7-7-2, Appendix C, p. 7.

³⁰⁰ Oral Hearing Transcript Volume 3, p. 577.

³⁰¹ Exhibit C7-7-2, Appendix C, pp. 8–9; T3:572, 580.

³⁰² Oral Hearing Transcript Volume 3, pp. 691–692.

³⁰³ FEI Final Submission, pp. 96–98.

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

Intervener submissions

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

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

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

FEI reply submission

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

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

³⁰⁴ AMPC/BCOAPO Final Submission, pp. 46–49.

³⁰⁵ CEC Final Submission, pp. 28–29.

³⁰⁶ FEI Reply Submission, pp. 67–72.

- (d) the Fernandez studies;
 - (e) the standard adjustment methodology employed by Value Line, Bloomberg and Merrill Lynch for equity return calculations;
 - (f) Mr. Coyne's own study results confirm that raw betas, and even Blume -adjusted betas, are understated;
 - (g) a list of additional studies that Mr. Coyne was asked to provide by way of undertaking;
 - (h) Mr. Coyne's evidence that Blume adjusted betas are widely used and accepted by regulators; and
 - (i) The betas used in the pension reports relied on by Dr. Booth as support for his MRP.
- The riskiness of utility stocks relative to the market should not be used as a basis for determining betas and the lower volatility of these stocks only suggests that betas should be less than one. Further, one would expect raw betas to be below adjusted betas for low beta stocks and the fact that the betas are lower is not an indication of whether raw betas need to be adjusted.

Commission determination

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

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

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

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

³⁰⁷ AMPC/BCOAPO Final Submission, p. 48.

With respect to the use of the Blume adjustment, the Panel notes Mr. Coyne's evidence presented in Figure 5.1 above which in his view, shows that unadjusted betas do a poor job of estimating expected returns and Blume adjusted betas still understate the actual return but the result is closer than using raw betas. The Panel is of the view that this analysis confirms, consistent with the Fernandez beta study Mr. Coyne refers to in his rebuttal evidence, the beta calculated using historical data is not a good approximation of a company's beta. In the Panel's view, this analysis confirms that an adjustment is needed but does not provide evidence of what the adjustment to beta should be. The Panel is also concerned that given the disruption in the capital markets during the period presented and recent merger and acquisition activity³⁰⁸ in the industry there may be confounding factors impacting the results of the analysis.

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

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

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

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

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

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

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

³⁰⁸ Oral Hearing Transcript Volume 3, pp. 584–585.

³⁰⁹ Exhibit A2-3, Brattle Group Report, pp. 15–16. (Emphasis added)

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

5.2.3.5 Dr. Booth's credit spread adjustment

In his evidence, Dr. Booth analyzed the volatility indices and the spread between corporate debt and Canada bonds and concludes that the increase in A credit spread to 191 bps from the typical average for the normal business cycle of 100 bps was caused partially by liquidity problems which have to be disentangled.³¹⁰ Dr. Booth recommends 50 percent adjustment to changes in credit spreads or 0.45 percent³¹¹ to adjust the current market effect. Dr. Booth regards this sort of adjustment as converting the CAPM into a conditional CAPM (CCAPM) where the CAPM holds conditional upon the state of the financial markets.³¹²

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

Intervener submissions

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

Commission determination

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

5.2.3.6 Appropriate CAPM estimate

Commission determination

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

³¹⁰ Exhibit C7-9, BCUCIR 13.2.

³¹¹ 91 basis point (191-100) with 50 percent adjustment.

³¹² Exhibit C7-9, BCUCIR 13.3.

³¹³ Exhibit B-18, Mr. Coyne Rebuttal, p. 33.

³¹⁴ AMPC/BCOAPO Final Submission, p. 53.

³¹⁵ CEC Final Submission, p. 40.

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

- i) A risk free rate plus an adjustment for abnormal conditions in the range of 3.8 to 4.0 percent. This is based on both experts agreeing that an adjustment to the risk free rate is necessary in the current market conditions and that both experts' end up with similar estimates.
- ii) MRP in the range of 6.3 to 7.0 percent based on:
 - a) Acceptance of Mr. Coyne's historical MRP of 6.3 including the use of income returns as opposed to total returns. This is based on third party evidence supporting his view as well as giving equal weight to Canadian and US historical MRP.
 - b) Consideration of forward-looking MRP estimates while placing more weight on historical because of the use of largely untested growth estimates in the forward-looking calculations and the Panel's view that forward-looking data is less reliable than historical estimates.
- iii) Beta estimate of approximately 0.6. The Panel considers the views of the parties that an upward adjustment to raw historical betas is necessary but given the lack of empirical evidence supporting their positions, the Panel places no reliance on the adjustment methods used by the experts. Consistent with the 2013 GCOC Decision, the Panel bases its determination on the range of estimates presented with an intermediate value of approximately 0.6.

5.2.4 Discounted cash flow estimates

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

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

- i) The value of the constant growth versus a multi-stage approach to using the DCF model.
- ii) Guidance the Panel can take from the submissions given the difference in approach to DCF taken by Dr. Booth and Mr. Coyne.
- iii) The appropriate weight to place on analyst estimates.

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

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

5.2.4.1 Constant growth and multi-stage DCF model variants

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

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

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

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

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

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

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

³¹⁷ Exhibit B-1, Appendix B, p. 51.

³¹⁸ Exhibit A2-3, Brattle Group Report, pp. 9, 26–27.

³¹⁹ Exhibit A2-3, Brattle Group Report, pp. 27–30. (emphasis in original)

³²⁰ Exhibit A2-3, Brattle Group Report, p. 30.

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

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

Table 5.5: Summary of DCF Estimates

Mr. Coyne		
DCF model type	Specification	DCF Estimates³²¹
Constant growth model ³²²	- Seven US and five Canadian proxy companies; - Earnings growth rates taken from SNL Financial, ValueLine, Zacks and First Call for each company in the Canadian and US proxy group.	Canada: 12.20% ³²³ US: 9.18% ³²⁴ Average: 10.69%
Multi-stage model (selected) ³²⁵	- Same companies and growth data source as constant growth model above; - Estimated company growth for Years 1 to 5; declining to long-term growth in Years 6-10; nominal GDP growth in Year 10+	Canada: 9.32% ³²⁶ US: 8.39% ³²⁷ Average: 8.86%
Dr. Booth		
DCF model type	Specification	DCF Estimates
Constant growth model ³²⁸	- Whole Canadian market - Sustainable growth rate range of 4.72 to 5.77%	Approximately 8.75% ³²⁹
Constant growth model ³³⁰	- US S&P 500 firms - Sustainable growth rate 6.91% (average)	Range: 9.04% to 10.14% ³³¹

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

³³² Exhibit C7-7-2, Direct Testimony of Dr. Booth, Appendix D, pp. 13-14.

³³³ Forecast growth rate 4% to 7%; Current dividend yield range from 2.29% to 4.02%. Average: 3.21% and median: 3.2%; Current (November 18, 2015) dividend yield: 1.98%.

³³⁴ Exhibit B-1, Appendix B, pp. 5-6, 58-59.

³³⁵ Exhibit C7-7-2, pp. 50-51, 58; Appendix D, pp. 6-17.

³³⁶ Exhibit C7-7-2, Appendix D, pp. 6-17; Ibid., pp. 50-51, 58.

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

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

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

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

Intervener submissions

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

³³⁷ Exhibit B-16, Rebuttal Testimony of Mr. Coyne, p. 36.

³³⁸ Exhibit B-16, pp. 35–37.

³³⁹ FEI Final Submission, pp. 89–90; T3:501.

³⁴⁰ FEI Final Submission, p. 90; T3:625–626.

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

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

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

FEI reply submission

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

5.2.4.2 Analyst estimates

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

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

³⁴¹ AMPC/BCOAPO Final Submission, p. 56; T3:601.

³⁴² AMPC/BCOAPO Final Submission, p. 58.

³⁴³ CEC Final Submission, pp. 19, 41.

³⁴⁴ FEI Reply Submission, p. 76.

³⁴⁵ Exhibit A2-3, Brattle Group Report, p. 29.

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

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

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

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

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

Intervener submissions

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

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

³⁴⁶ Exhibit B-1, Appendix B, pp. 55–56.

³⁴⁷ Exhibit C7-7-2, Appendix D, pp. 14–15.

³⁴⁸ FEI Final Submission, pp. 86–88.

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

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

FEI reply submission

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

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

AMPC/BCOAPO sur-reply

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

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

Commission determination

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

³⁴⁹ CEC Final Submission, pp. 18, 41.

³⁵⁰ FEI Reply Submission, pp. 73-74.

³⁵¹ AMPC/BCOAPO Sur-Reply, pp. 2-3.

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

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

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

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

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

Dr. Booth also introduced a version of the sustainable growth rate DCF approach asserting that a median ROE of 7.02 percent results when applied against his US proxy group of eight utilities. Dr. Booth did not provide evidence as to the level of adoption of this approach in Canada and the US although Mr. Coyne pointed out that FERC has moved away from any reliance on sustainable growth rates, a point the Panel notes was not contested. The Panel observes that Dr. Booth took into account only internally generated funds and neglected to take into account externally generated funds such as the issuance of new equity. This concern was raised by Mr. Coyne and AMPC/BCOAPPO responded to this by stating Dr. Booth’s explanation is FEI has provided no evidence it will dilute its capital stock by an amount that is non negligible and thus the $s \times v$ is effectively zero. While FEI does not issue equity to the public, the Panel notes FEI’s equity financing requirements of \$594 million related to expected capital expenditures in 2016-2018 (see Table 4.4) will likely require the shareholder to make equity injections to maintain FEI’s approved equity structure. In addition, Dr. Booth’s sustainable growth model is applied to his proxy group, not FEI, and therefore whether FEI is to issue new equity is irrelevant given they were not part of the proxy group. The Panel is of the view that the lack of consideration of the potential for proxy

companies to issue equity is important and could have resulted in a different set of outcomes. **Therefore, the Panel finds that no weight can be placed on Dr. Booth's sustainable growth rate model for his US proxy group as it is not based on a more robust and comprehensive version of this model.** Moreover, the Panel remains unpersuaded as to whether it is valid to apply the sustained growth rate model itself. There has been limited evidence in this proceeding on the model, its variations and the level of adoption in other jurisdictions. Given these limitations, the Panel views any results attributed to the use of this model with caution.

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

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

c) Analyst's Estimates

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

Given these considerations, the Panel finds that caution must be exercised with analyst estimates due to the potential for optimism bias but is not persuaded the evidence supports the need to adjust analyst forecasts related to the utility industry.

³⁵² Oral Hearing Transcript Volume 2, p. 422.

³⁵³ 2013 GCOC Decision, p. 71.

³⁵⁴ 2012 GCOC proceeding, Exhibit B-26, p. 21.

5.2.4.3 Appropriate DCF estimate

Commission determination

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

5.2.5 Financing flexibility adjustment

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

Both Mr. Coyne and Dr. Booth agree that 50 bps is a reasonable financing flexibility adjustment³⁵⁷ and Mr. Coyne is of the view an adjustment of 50 bps is common regulatory practice in Canada.³⁵⁸

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

CEC submits 50 bps is reasonable.³⁶⁰

Commission determination

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

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

³⁵⁵ 2013 GCOC Decision, p. 80.

³⁵⁶ 2013 GCOC Decision, p. 79.

³⁵⁷ Exhibit B-1, Appendix B, p. 60.

³⁵⁸ Exhibit B-9, BCUC IR 39.1.

³⁵⁹ FEI Final Submission, pp. 99–100.

³⁶⁰ CEC Final Submission, p. 14.

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

5.2.5.1 FEI’s ROE relative to other Canadian utilities

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

Table 5.6: Canadian Peer Group Comparative Risk Analysis and Authorized ROE³⁶²

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

Panel discussion

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

³⁶¹ Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism (2006 TGI ROE), Decision dated March 2, 2006, pp. 54–55.

³⁶² Exhibit B-1, Appendix B, p. 101.

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

5.3 Appropriate return on equity

Commission determination

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

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

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

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

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

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

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

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

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

6.0 AUTOMATIC ADJUSTMENT MECHANISM

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

An AAM based on changes to long-term Canada bond rates was first implemented by the Commission in 1994³⁶³ but in 2009, by Order G-158-09, it was eliminated. In eliminating the AAM in 2009, the Commission stated, "in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the Fair Return Standard."³⁶⁴ In the 2013 GCOC Decision, the AAM was reinstituted on the basis that it "better meets the FRS than giving no consideration to market changes over the period between ROE proceedings." The Commission in this instance addressed some of the concerns with previous mechanisms and established a two variable model taking into account utility bond spreads as well as long-term Canada Bond yields. However, in recognition of the effect of monetary policy on bond rates, the Commission directed any implementation of this mechanism be subject to an actual long-term Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula would not apply unless the long Canada bond yield was below 3.8 percent.³⁶⁵ The Canada long-term bond yield has remained below the 3.8 percent threshold since 2013 and therefore, the AAM was not applied to FEI's ROE during the period since the 2013 GCOC Decision.³⁶⁶

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

³⁶³ 2013 GCOC Decision, p. 81.

³⁶⁴ Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure (2009 TGI ROE), Decision dated December 16, 2009.

³⁶⁵ Ibid., pp. 90–91.

³⁶⁶ Exhibit B-1, p. 32.

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

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

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

Intervener submissions

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

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

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

³⁶⁷ Exhibit B-1, pp. 32–33; FEI Final Submission, p. 101.

³⁶⁸ FEI Final Submission, pp. 101–102.

³⁶⁹ Exhibit B-1, Appendix B, p. 103.

³⁷⁰ Exhibit B-16, p. 10.

³⁷¹ AMPC/BCOAPO Final Submission, p. 69.

³⁷² Exhibit C7-7-1, p. 63.

³⁷³ Exhibit C7-7-1, p. 63.

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

Commission determination

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

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

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

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

7.0 FEI AS THE BENCHMARK UTILITY

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

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

³⁷⁴ CEC Final Submission, p. 117.

³⁷⁵ Order G-148-12, Reasons for Decision, p. 4.

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

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

Commission determination

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

³⁷⁶ Exhibit B-1, pp. 34–35.

³⁷⁷ CEC Final Submission, p. 118.

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

Original Signed By

K. A. KEILTY
PANEL CHAIR / COMMISSIONER

Original Signed By

D. A. COTE
COMMISSIONER

Original Signed By

N. E. MACMURCHY
COMMISSIONER



ORDER NUMBER
G-129-16

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

and

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

BEFORE:

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

on August 10, 2016

ORDER

WHEREAS:

- A. On October 2, 2015, FortisBC Energy Inc. (FEI) filed an application for a review of its common equity component and return on equity for 2016 (Application) pursuant to the British Columbia Utilities Commission (Commission) decision in the Generic Cost of Capital Stage 1 proceeding;
- B. In its Application, FEI submits that the amalgamated FEI (the amalgamation of three affiliated entities: the former FortisBC Energy Inc., FortisBC Energy [Whistler] Inc. and FortisBC Energy [Vancouver Island] Inc.) continues to be the logical choice to serve as the benchmark utility for the purpose of determining the cost of capital for other utilities;
- C. By Order G-177-15 dated November 9, 2015, the Commission established a proceeding to review the Application. The regulatory review was by way of a limited scope oral hearing and included two rounds of information requests (IRs) to FEI and one round of IRs on intervenor evidence;
- D. Six parties registered as intervenors in this proceeding. Among those registered, the most active were the Commercial Energy Consumers of British Columbia, the British Columbia Old Age Pensioners' Association *et al.* and the Association of Major Power Customers of BC (AMPC): collectively, the "Utility Customers";
- E. On December 7, 2015, the Commission issued Order G-193-15 in the FEI Annual Review of 2016 Delivery Rates Decision setting interim delivery rates for all non-bypass customers effective January 1, 2016 and approving FEI's existing capital structure and return on equity on an interim basis effective January 1, 2016, pending the outcome of this cost of capital proceeding;
- F. On December 15, 2015, the Commission issued Order G-204-15 and ordered, among other things, that FEI's existing common equity component and return on equity would remain the benchmark on an interim basis, effective January 1, 2016;

- G. On January 26, 2016, the Utility Customers filed intervenor evidence of their expert witness, Dr. Laurence Booth;
- H. The oral hearing took place from March 9, 2016 to March 11, 2016;
- I. The argument phase of the proceeding took place from April 3, 2016 to April 28, 2016. On May 5, 2016, AMPC sought leave to file two narrow sur-reply submissions;
- J. By Order G-68-16 dated May 13, 2016, the Commission, after considering comments from FEI and other interveners, allowed the sur-reply to remain on record; and
- K. The Commission has reviewed and considered all of the evidence and submissions on record for the proceeding.

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

- 1. FortisBC Energy Inc.'s common equity component is set at 38.5 percent, effective January 1, 2016.
- 2. FortisBC Energy Inc.'s return on equity is set at 8.75 percent, effective January 1, 2016.
- 3. The use of the Automatic Adjustment Mechanism formula is suspended indefinitely.
- 4. The common equity component and return on equity approved for FortisBC Energy Inc. in the decision issued concurrently with this order will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.
- 5. The common equity component and return on equity will remain in effect until otherwise determined by the Commission.
- 6. FortisBC Energy Inc.'s interim rates set by Order G-193-15 are approved as permanent, effective January 1, 2016. FortisBC Energy Inc. is to file, within 15 working days from the date of this order, updated final rate schedules in accordance with Directives 1 and 2 of this order.

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

BY ORDER

Original Signed By:

K. A. Keilty
Commissioner

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

LIST OF ACRONYMS

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

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

LIST OF APPEARANCES

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

E. Cheng	Commission Staff
L. Cheung	Commission Staff

S. Allen	Consulting Staff

Allwest Reporting Ltd.	Court Reporters

LIST OF PANELS

FORTISBC ENERGY INC.

Expert Opinion on a Benchmark Fair Return

James M. Coyne

ConcentricAdvisors

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

Laurence D. Booth, DBA

University of Toronto

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

and

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

EXHIBIT LIST

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

- A-13 Letter dated March 3, 2016 – Oral Hearing information
- A-14 Letter dated May 6, 2016 – Request for Submissions on AMPC’s request to file sur-reply submissions
- A-15 Letter dated May 13, 2016 – Commission Order G-68-16 with reasons for decision on AMPC’s request for leave to file sur-reply

COMMISSION STAFF DOCUMENTS

- A2-1 Letter dated November 25, 2015 – Commission staff filing FortisBC Energy Inc. – Price Risk Management Workshop Summary Report (October 27, 2015)
- A2-2 Letter dated January 12, 2016 – Commission staff filing Morningstar Australasia Pty Ltd. – Morningstar Stock Sector Structure (2011)
- A2-3 Letter dated January 13, 2016 – Commission staff filing The Brattle Group – Survey of Cost of Capital Practices in Canada (May 31, 2012)
- A2-4 Submitted at Oral Hearing March 10, 2016 - NEW JERSEY RESOURCES, INVESTOR FACT SHEET, DATED NOVEMBER 13, 2015
- A2-5 Submitted at Oral Hearing March 10, 2016 - THREE-PAGE EXCERPT FROM STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES DECISION, "EXHIBIT P-1"
- A2-6 Submitted at Oral Hearing March 10, 2016 - TWO-PAGE EXCERPT FROM STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES DECISION, RE: EVIDENCE OF PAUL R. MOUL
- A2-7 Submitted at Oral Hearing March 10, 2016 - EXCERPTS FROM ATMOS ENERGY CORPORATION 2014 SUMMARY ANNUAL REPORT, "INVESTING FOR SAFETY"
- A2-8 Submitted at Oral Hearing March 10, 2016 - DALLAS MORNING NEWS ARTICLE DATED AUGUST 19, 2013
- A2-9 Submitted at Oral Hearing March 10, 2016 - EXCERPT FROM FORTISBC WEBSITE, "SWITCH TO NATURAL GAS AND SAVE"
- A2-10 Submitted at Oral Hearing March 10, 2016 - EXCERPTS FROM WRITTEN EVIDENCE OF JAMES H. VANDER WEIDE

APPLICANT DOCUMENTS

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

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

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

INTERVENER DOCUMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- C7-11 Letter dated March 9, 2016 – AMPC submitting Booth Opening Statement
- C7-12 Submitted at Oral Hearing March 9, 2016 - AMPC BOOK OF DOCUMENTS
- C7-13 Submitted at Oral Hearing March 10, 2016 - FEI 2016 ROE AMPC WITNESS AID

INTERESTED PARTY DOCUMENTS

- D-1 **UNION GAS LIMITED (UNION GAS)** Letter Dated November 16, 2015 – Request change to Interested Party from Intervener Status by Patrick McMahon
- D-2 **CORIX MULTI-UTILITY SERVICES INC. (CORIX)** Letter Dated November 18, 2015 – Request for Interested Party Status by Ian Wigington
- D-2-1 Letter Dated December 4, 2015 – Corix Submission on interim order
- D-3 **PACIFIC NORTHERN GAS LTD. (PNG)** Letter Dated November 23, 2015 – Request for Interested Party Status by Janet Kennedy, Verlon Otto and Anwar Chaudry
- D-3-1 **PACIFIC NORTHERN GAS LTD.** Letter dated December 3, 2015 - Submission regarding Interim Order Exhibit A-5
- D-4 **CREATIVE ENERGY (CE)** Letter Dated November 23, 2015 – Request for Interested Party Status by Michelle McLarty
- D-5 **SENTINEL ENERGY MANAGEMENT INC. (SENTINEL)** Letter Dated December 7, 2015 – Request for Late Interested Party Status by Jim Langley

LETTERS OF COMMENT

- E-1 **RIVER DISTRICT ENERGY** Letter dated December 1, 2015 - Submission regarding Interim Order Exhibit A-5
- E-2 **FORTISBC ALTERNATIVE ENERGY SERVICES INC. (FAES)** Letter dated December 3, 2015 - Submission regarding Interim Order Exhibit A-5
- E-3 **FORTISBC INC. (FBC)** Letter dated December 3, 2015 - Submission regarding Interim Order Exhibit A-5
- E-3-1 Letter Dated December 9, 2015 – FBC Reply Submission regarding Interim Order